NorthWestern® Energy

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

DOCKET NO. D2016.9.68

Application for Authority to Change and Establish Natural Gas Delivery Service and Production Rates

Revenue Requirement (Phase One)

Allocated Cost of Service and Rate Design (Phase Two)

TESTIMONY AND EXHIBITS (PHASE ONE)

VOLUME I

September 30, 2016

September 30, 2016

Mr. Will Rosquist
Administrator, Regulatory Division
Montana Public Service Commission
1701 Prospect Ave.
PO Box 202601
Helena MT 59620-2601

RE: Docket No. D2016.9.68 – Application for Approval to Change and Establish Natural Gas Delivery Service and Production Rates.

Dear Mr. Rosquist:

NorthWestern Energy ("NorthWestern") hereby submits this request to the Montana Public Service Commission ("MPSC" or "Commission") for authority to increase Natural Gas Delivery Service and Production Rates, and place the Bear Paw (NFR) and South Bear Paw (Devon) Natural Gas Production Properties in rate base ("Application").

NorthWestern is a Delaware corporation providing electric and natural gas utility services in Montana and is subject to the jurisdiction of the Commission. NorthWestern makes this Application pursuant to §§ 69-3-301 through 69-3-330, MCA, regarding the rates of public utilities; §§ 2-4-101 through 2-7-711, MCA, regarding administrative proceedings; and Administrative Rules of Montana ("ARM") 38.5.101 through 38.5.195 regarding this Commission's rules for minimum rate case filing standards for public utilities. The filed cost of service includes the information required in ARM 38.5.103 through 38.5.175, 38.5.179 through 38.5.183, and 38.5.190. The Commission has granted NorthWestern bifurcation of the revenue requirement from the allocated cost of service and rate design as required under ARM 38.5.176 and ARM 38.5.177. The allocated cost of service and rate design portion of this filing will be submitted by NorthWestern by April 1, 2017.

For NorthWestern's Natural Gas Utility, this filing addresses the transmission, distribution, storage, and production cost of service for serving MPSC jurisdictional natural gas customers.

APPLICATION

Natural Gas Utility Cost of Service

NorthWestern's Natural Gas Utility delivery services' revenue deficiency is $7,371,955. This revenue deficiency is calculated for the test period, which is the 12-months-ended December 2015, adjusted for normalized and known and measurable changes in accordance with ARM 38.5.106.

NorthWestern's Natural Gas Utility total production revenue deficiency is $3,520,483. This revenue deficiency is made up of $13,382 for Battle Creek, $1,513,065 for Bear Paw (NFR), and $1,994,036 for South Bear Paw (Devon). The revenue deficiency for the Natural Gas Utility production is calculated for the test period, which is also the 12-months-ended December 2015, adjusted for normalized and known and measurable changes in accordance with ARM 38.5.106. In addition, prior to this filing, shared administrative costs were allocated to transmission, distribution, and storage. With this filing, shared administrative costs are also allocated to production.

NorthWestern acquired the Bear Paw (NFR) and South Bear Paw (Devon) Natural Gas Production Properties subsequent to filing its application to place Battle Creek Natural Gas Production Properties in rate base. Since the November 2012 Bear Paw (NFR) acquisition and the December 2013 South Bear Paw (Devon) acquisition, both have been included in the natural gas supply tracker on an interim basis. This filing includes a request that the revenue recovery be trued-up to actual costs for the prior periods when interim rates were in effect.

In Order No. 7282d, Consolidated Docket Nos. D2013.5.34 and D2014.5.47, the Commission ordered NorthWestern to make a comprehensive filing no later than October 6, 2016 that included data to consider rates for production assets under a range of regulatory approaches. NorthWestern is including that required filing with this Application and is proposing to true-up the Natural Gas production assets cost of service rates on an annual basis in the future.

DOCUMENTS SUBMITTED WITH THIS APPLICATION

The following materials are submitted with this Application:

1. The Application with current base rates[1] and proposed Natural Gas service rates attached in summary as Appendix A;

[1] Rates exclude the tax tracker deferred balance from Order No. 7451a in Docket No. D2015.10.81.

2. Appendix B summary of the residential customer bill impact of the proposed rates;

3. A proposed Notice of Interim Rate Adjustment Request, a Certificate of Service of Notice of Interim Rate Adjustment Request to the media, and the Interim Rate workpapers;

4. Prefiled direct testimony and exhibits of NorthWestern's witnesses;

5. All material required by the Commission's filing requirements, ARM 38.5.101 through 38.5.175, 38.5.179 through 38.5.183, and 38.5.190.

6. Information supporting final true-up of historical Bear Paw (NFR) and South Bear Paw (Devon) Natural Gas production assets fixed costs of service; and

7. All material required by Order No. 7282d in Consolidated Docket Nos. D2013.5.34 & D2014.5.47.

SERVICE

An original and eleven copies of the above are submitted with this filing, and three copies are being provided to the Montana Consumer Counsel ("MCC"). One copy of this filing is also being mailed to each of the parties on the service list from Docket No. D2012.9.94, NorthWestern Energy's last general rate filing.

All of the above materials will be available for public inspection at the following locations:

The Montana Public Service Commission
1701 Prospect Avenue
Helena, Montana 59620-2601

Montana Consumer Counsel
111 North Last Chance Gulch, Suite 1B
Helena, Montana 59620-2601

NorthWestern Energy
11 East Park
Butte, Montana 59701

NorthWestern requests that the Commission publish legal notice to inform the public that this Application has been made.

While electronic information is not required by the Commission rules, nor is it standard practice to provide this data at this stage of a filing, electronic spreadsheet versions of exhibits, statements, electronic data supporting tables

and charts included in testimony, and electronic supporting workpapers are being compiled and will be provided on CD as soon as possible.

EFFECT ON CUSTOMERS

The estimated number of natural gas delivery service customers whose cost of service will be affected, and the annual amounts of the increase on a uniform percentage basis to each class of customers, are as follows:

Customer Classification	Average No. Customers	Annual Increase Delivery Service Cost of Service	Annual Increase Production Cost of Service	Total Cost of Service
Residential	166,071	$3,904,061	$2,295,033	$6,199,094
General Service	23,359	$2,047,268	$1,182,336	$3,229,604
Utility	4	$21,261	$43,114	$64,375
DBU – Transportation	224	$155,219		$155,219
TBU – Transportation	32	$830,026		$830,026
Storage	N/A	$226,695		$226,695
DBU – Interruptible Trans.	N/A	$2,218		$2,218
TBU – Interruptible Trans.	N/A	$157,279		$157,279
Rounding		$27,928		$27,928
Total		$7,371,955	$3,520,483	$10,892,438

The total Natural Gas service increase represents an overall percentage change in delivery services and production of 7.96%, totaling $10,892,438. However, the overall bill impact to individual customer classes depends upon the type of customer. For a typical residential customer using 100 therms per month of natural gas, the total bill impact will be approximately $4.81 per month or 6.77%.

NORTHWESTERN CONTACTS

The NorthWestern employee responsible for answering questions concerning this rate change request or for inquiries to the appropriate members of the utility staff is:

Mr. Patrick R. Corcoran, Vice President
Government and Regulatory Affairs
NorthWestern Energy
11 East Park
Butte, Montana 59701
pat.corcoran@northwestern.com

NorthWestern's attorney in this matter is:

Al Brogan
NorthWestern Energy
208 N. Montana, Suite 205
Helena, Montana 59601
Tel. (406) 443-8903
Fax (406) 443-8979
al.brogan@northwestern.com

NorthWestern asks that the names of Patrick Corcoran, Connie Moran, Al Brogan, and Joe Schwartzenberger appear on all service lists in this proceeding.

INTERIM RATE ADJUSTMENT

Pursuant to ARM 38.5.501 through 38.5.508 and as shown in the Interim section of this filing, NorthWestern is also requesting interim increases for uniform changes to the adjusted natural gas delivery service rates and interim decreases for uniform changes to the Battle Creek fixed production rates. The requested interim revenue requirement increase in delivery service for Natural Gas Utility customers is $5,596,577 or a 4.88% increase; the requested interim revenue requirement decrease for the fixed Battle Creek production rates is ($22,455) or (0.95%).

Pursuant to ARM 38.5.503, notice has been served on the MCC as part of this filing and on all parties on the service list in Docket No. D2012.9.94, NorthWestern's last general rate case filing. Notice has also been mailed to the media for general dissemination throughout NorthWestern's natural gas service area. The rates that would generate the requested interim revenue increases for the Natural Gas Utility are also included in the Interim section of this filing.

In contrast to the request for final rate approval, the interim rates for the Natural Gas Utility have been calculated based on the 9.80% cost of equity resulting from Docket No. D2012.9.94, which results in an overall Natural Gas Rate of Return on rate base of 7.08%. Finally, the interim request includes several other adjustments, which are detailed in the Interim workpapers.

Respectfully Submitted,

Patrick R Corcoran BY JS.

Patrick R. Corcoran
Vice President Government and Regulatory Affairs

Enclosures

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Attorney for NorthWestern Energy

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER OF NorthWestern Energy's Application for Approval to Change and Establish Natural Gas Delivery Service and Production Rates	))))	REGULATORY DIVISION DOCKET NO. D2016.9.68

APPLICATION

NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern" or "Applicant") by and through its undersigned counsel, respectfully submits this Application for Approval to Change and Establish Natural Gas Delivery Service and Production Rates ("Application") to the Montana Public Service Commission ("Commission") in the above-captioned docket. In support thereof, NorthWestern states as follows:

I.

Applicant's full name and address are:

NorthWestern Energy
11 East Park Street
Butte, MT 59701

II.

Applicant is a Delaware corporation doing business as NorthWestern Energy in the states of Montana, South Dakota, and Nebraska as a public utility.

III.

The following described tariff sheets are the Natural Gas service tariff sheets impacted by the proposals in this Application that are presently in effect in Montana and on file with the Commission. All other rate schedule gas tariff sheets remain as previously approved by the Commission:

Natural Gas Rates:

Schedule	Description	Sheet No.
D-RG-1	Residential Natural Gas Service	10.1
D-RGCA-1	Residential Gas Core Aggregation Service	11.1
D-GSG-1	General Natural Gas Service	20.1
D-GSGCA-1	General Service Gas Core Aggregation	21.1
D-FTG-1	Firm Transportation Natural Gas Service	25.1
D-ITG-1	Interruptible Transportation Natural Gas Service	27.1
T-FUGC-1	Firm Utility Gas Contract Service	30.1
T-FTG-1	Firm Transportation Natural Gas Service	80.1
T-ITG-1	Interruptible Transportation Natural Gas Service	85.1
T-FSG-1	Firm Storage Natural Gas Service	90.1
GTC-1	General Terms and Operating Conditions	95.3 through 95.26 (inclusive)
AGTC-1	Aggregation General Terms and Conditions	96.2 through 96.6 and 96.8 through 96.21 (inclusive)

The applicable rates and rate changes for these tariff sheets, except for the language changes for Schedules GTC-1 and AGTC-1, are summarized in Appendix A (attached hereto).

IV.

NorthWestern's currently authorized rates for Natural Gas delivery service and production are no longer just and reasonable rates as they do not allow NorthWestern to recover its costs of providing Natural Gas delivery service and production nor do they provide NorthWestern an opportunity to earn a fair and reasonable return on its investments. For example, NorthWestern's Natural Gas transmission, distribution, and storage rate base has increased 16.4% since the Commission's final order in the previous general rate case, Docket No. D2012.9.94.

V.

NorthWestern has prepared, and files concurrently with this Application, its cost of providing Natural Gas Utility service in Montana based upon a 2015 test year, adjusted for known and measurable changes. The filed cost of service includes the information required in the Commission's Minimum Rate Case Filing Standards, ARM 38.5.103 through 38.5.175, 38.5.179 through 38.5.183, and 38.5.190. On September 13, 2016, the Commission granted NorthWestern's Motion to Bifurcate this Rate Case ("Motion"). Pursuant to the Motion, NorthWestern will file Phase II (Allocated Cost of Service/Rate Design) on or before April 1, 2017.

VI.

The cost of service filed concurrently with this Application establishes that NorthWestern has a revenue deficiency for its Natural Gas Utility of $10,892,438 ($7,371,955 for delivery service and $3,520,483 for production). Attached as Appendix A are summaries of current base[1] rates and proposed new base rates for Natural Gas Utility delivery service and production. These summaries include all Natural Gas service proposed base rate changes for each tariff listed in paragraph III above. (The proposed changes to Schedules GTC-1 and AGTC-1 are not rate changes.) Attached as Appendix B are summaries of the typical bill impact of the proposed rates for a residential customer using 100 therms per month. These proposed base rates are just and reasonable; the Commission should approve them.

[1] Rates exclude the tax tracker deferred balance from Order No. 7451a in Docket No. D2015.10.81.

VII.

In addition to filing its cost of service in support of this Application, NorthWestern files concurrently all necessary prefiled direct testimony, exhibits, and workpapers.

VIII.

Pursuant to § 69-3-304, MCA, and ARM 38.5.101 through 38.5.508, NorthWestern requests an interim increase of $5,596,577 in its Natural Gas base transmission, distribution, and storage rates and an interim decrease of $22,455 in its Natural Gas fixed production rates for the Battle Creek Natural Gas production assets. Support for the interim rate changes is set forth in the Interim Section of this filing.

WHEREFORE, Applicant respectfully requests that the Commission:

1. After hearing as provided by law, issue an order approving as authorized final rates, the rates set for Natural Gas delivery service and production set forth in Appendix A;

2. Approve an interim general rate increase in Natural Gas delivery rates in the amount of $5,596,577 and an interim rate decrease in Battle Creek Natural Gas fixed production rates of $22,455.

3. Approve inclusion of the Bear Paw (NFR) and South Bear Paw (Devon) Natural Gas production assets in rate base;

4. Approve final true-up to historical Bear Paw (NFR) and South Bear Paw (Devon) Natural Gas production assets fixed costs of service;

5. Approve NorthWestern's proposal to true-up the Natural Gas production assets cost of service rates on an annual basis going forward; and

6. Approve the tariff revisions to Schedules GTC-1 and AGTC-1 as described in this filing.

Respectfully submitted this 30th day of September, 2016.

NorthWestern Energy

By: _____

Al Brogan
Attorney for Applicant

	A	B	C	D	E	F
1	**NorthWestern Energy**					
2	**Natural Gas Utility**					
3	**Proposed Tariff Rates**					
4						
5	NorthWestern Energy					
6						
7						
8						
9	**CORE SALES SERVICE**	Docket No. D2015.10.81 Order No. 7451a Without Tax Deferred		Increase		Proposed Rates
10						
11	**Residential Natural Gas Service**					
12	D-RG-1 Rate Schedule					
13	Monthly Service Charge per Meter	$ 7.29		$ 0.46		$ 7.75
14	Commodity Charges:					
15	Distribution	$ 0.2098629		$ 0.0135144		$ 0.2233773
16	Transmission	$ 0.1242724		$ 0.0080027		$ 0.1322751
17	Storage	$ 0.0378218		$ 0.0024356		$ 0.0402574
18	Gas Supply Charge	$ 0.2544100		$ 0.0194723		$ 0.2738823
19	Total Commodity Charge (Therms)	$ 0.6263671				$ 0.6697921
20						
21						
22	**Residential Gas Core Aggregation Service**					
23	D-RGCA-1 Rate Schedule					
24	Monthly Service Charge per Meter	$ 7.29		$ 0.46		$ 7.75
25	Commodity Charges:					
26	Distribution	$ 0.2098629		$ 0.0135144		$ 0.2233773
27	Transmission	$ 0.1242724		$ 0.0080027		$ 0.1322751
28	Storage	$ 0.0378218		$ 0.0024356		$ 0.0402574
29	Total Commodity Charge (Therms)	$ 0.3719571				$ 0.3959098
30						
31						
32	**General Natural Gas Service**					
33	D-GSG-1 Rate Schedule					
34	Monthly Service Charge per Meter					
35	0 to 300	$ 18.94		$ 1.21		$ 20.15
36	301 to 1,000	$ 24.99		$ 1.61		$ 26.60
37	1,001 to 2,000	$ 40.26		$ 2.59		$ 42.85
38	2,001 to 5,000	$ 67.59		$ 4.36		$ 71.95
39	5,001 to 10,000	$ 83.05		$ 5.35		$ 88.40
40	10,001 to 30,000	$ 131.25		$ 8.50		$ 139.75
41	> 30,000	$ 159.48		$ 10.32		$ 169.80
42	Commodity Charges:					
43	Distribution	$ 0.2028941		$ 0.0130657		$ 0.2159598
44	Transmission	$ 0.1201183		$ 0.0077352		$ 0.1278535
45	Storage	$ 0.0364751		$ 0.0023489		$ 0.0388240
46	Gas Supply Charge	$ 0.2544100		$ 0.0194723		$ 0.2738823
47	Total Commodity Charge (Therms)	$ 0.6138975				$ 0.6565196
48						
49	**General Service Gas Core Aggregation**					
50	D-GSGCA-1 Rate Schedule					
51	Monthly Service Charge per Meter					
52	0 to 300	$ 18.94		$ 1.21		$ 20.15
53	301 to 1,000	$ 24.99		$ 1.61		$ 26.60
54	1,001 to 2,000	$ 40.26		$ 2.59		$ 42.85
55	2,001 to 5,000	$ 67.59		$ 4.36		$ 71.95
56	5,001 to 10,000	$ 83.05		$ 5.35		$ 88.40
57	10,001 to 30,000	$ 131.25		$ 8.50		$ 139.75
58	> 30,000	$ 159.48		$ 10.32		$ 169.80
59	Commodity Charges:					
60	Distribution	$ 0.2028941		$ 0.0130657		$ 0.2159598
61	Transmission	$ 0.1201183		$ 0.0077352		$ 0.1278535
62	Storage	$ 0.0364751		$ 0.0023489		$ 0.0388240
63	Total Commodity Charge	$ 0.3594875				$ 0.3826373

	A	B	C	D	E	F
1		**NorthWestern Energy**				
2		**Natural Gas Utility**				
3		**Proposed Tariff Rates**				
4						
5	NorthWestern Energy					
6						
7						
8						
9	**CORE SALES SERVICE**	Docket No. D2015.10.81 Order No. 7451a Without Tax Deferred		Increase		Proposed Rates
64						
65						
66	**Firm Utility Gas Contract Service**					
67	T-FUGC-1 Rate Schedule					
68	Monthly Service Charge per Meter					
69	10,001 to 30,000	$ 127.78		$ 8.27		$ 136.05
70	> 30,000	$ 329.40		$ 21.30		$ 350.70
71						
72	Transmission Charges:					
73	Reservation Rate (MDDQ)	$ 0.6220535		$ 0.040058		$ 0.6621116
74	Transmission Commodity Rate (Therms)	$ 0.0074147		$ 0.000478		$ 0.0078922
75						
76	Storage Charges:					
77	Reservation Rate (MDDQ)	$ 0.4947281		$ 0.0318588		$ 0.5265869
78	Storage Commodity Rate (Therms)	$ 0.0017897		$ 0.0001153		$ 0.0019050

	A	B	C	D	E	F
1	**NorthWestern Energy**					
2	**Natural Gas Utility**					
3	**Proposed Tariff Rates**					
4	NorthWestern Energy					
5						
6						
7						
8	**NONCORE: TRANSPORTATION SERVICE**	Docket No. D2015.10.81 Order No. 7451a Without Tax Deferred		Increase		Proposed Rates
9						
10						
11	***Distribution Business Unit:***					
12	**Firm Transportation Natural Gas Service**					
13	D-FTG-1 Rate Schedule					
14						
15	Monthly Service Charge per Meter					
16	Distribution Level Meter Charges:					
17	2,000 to 5,000	$ 122.34		$ 7.91		$ 130.25
18	5,001 to 10,000	$ 139.80		$ 9.05		$ 148.85
19	10,001 to 30,000	$ 192.19		$ 12.41		$ 204.60
20	> 30,000	$ 223.22		$ 14.43		$ 237.65
21						
22	Distribution Charge: ($/MDDQ)					
23	Monthly Reservation Rate/Trans. MDDQ	$ 0.7739992		$ 0.0498428		$ 0.8238420
24						
25						
26	**Interruptible Transportation Natural Gas Service**					
27	D-ITG-1 Rate Schedule					
28						
29	Monthly Service Charge per Meter					
30	Distribution Level Meter Charges:					
31	2,000 to 5,000	$ 122.34		$ 7.91		$ 130.25
32	5,001 to 10,000	$ 139.80		$ 9.05		$ 148.85
33	10,001 to 30,000	$ 192.19		$ 12.41		$ 204.60
34	> 30,000	$ 223.22		$ 14.43		$ 237.65
35						
36	Distribution Charge: ($/MDDQ)					
37	Commodity Charge - Maximum	$ 0.0254495		$ 0.0016389		$ 0.0270884
38						
39						
40	***Transportation Business Unit:***					
41	**Firm Transportation Natural Gas Service**					
42	T-FTG-1 Rate Schedule					
43						
44	Monthly Service Charge per Meter					
45	Transmission Level Meter Charges:					
46	5,001 to 10,000	$ 119.71		$ 7.74		$ 127.45
47	10,001 to 30,000	$ 172.08		$ 11.12		$ 183.20
48	> 30,000	$ 381.83		$ 24.67		$ 406.50
49						
50	Transmission Charge:					
51	Monthly Reservation Rate/Trans. MDDQ	$ 0.9784615		$ 0.0630095		$ 1.0414710
52	Commodity Charge - Maximum	$ 0.0074147		$ 0.0004775		$ 0.0078922
53						

	A	B	C	D	E	F
1	**NorthWestern Energy**					
2	**Natural Gas Utility**					
3	**Proposed Tariff Rates**					
4	NorthWestern Energy					
5						
6						
7						
8	**NONCORE: TRANSPORTATION SERVICE**	Docket No. D2015.10.81 Order No. 7451a Without Tax Deferred		Increase		Proposed Rates
54						
55	**Interruptible Transportation Natural Gas Service**					
56	T-ITG-1 Rate Schedule					
57						
58	Monthly Service Charge per Meter					
59	Transmission Level Meter Charges:					
60	5,001 to 10,000	$ 119.71		$ 7.74		$ 127.45
61	10,001 to 30,000	$ 172.08		$ 11.12		$ 183.20
62	> 30,000	$ 381.83		$ 24.67		$ 406.50
63						
64						
65	Transmission Charge:					
66	Commodity Charge - Maximum	$ 0.0395798		$ 0.0025488		$ 0.0421286
67						
68						
69	**Firm Storage Natural Gas Service**					
70	T-FSG-1 Rate Schedule					
71						
72	Monthly Rate:					
73	T-FSG-1 Rate Schedule					
74	Withdrawal Reservation Charge	$ 0.4675642		$ 0.0301095		$ 0.4976737
75	Capacity Commodity Charge	$ 0.0022955		$ 0.0001478		$ 0.0024433
76	Injection Commodity Charge	$ 0.0024163		$ 0.0001556		$ 0.0025719
77	Withdrawal Commodity Charge	$ 0.0024163		$ 0.0001556		$ 0.0025719

NorthWestern Energy

Residential Services - Typical Bill Amount

	A	B	C	D	E	F	G	H	I	J	K
7				Final Order No. 7451a Adjusted			Proposed Rates Uniform Basis				
10	**Usage in therms**	**100**		**1-Sep-16**	**Total Bill**			**Total Bill**		**Bill**	**Percentage**
11				**Rate**	**Amount**		**Rate**	**Amount**		**Change**	**Change**
12	Monthly Service Charge per Meter		[1]	$ 7.29	$ 7.29		$ 7.75	$ 7.75		$ 0.46	6.31%
13											
14	Commodity Charges: (Monthly $/Therm)										
15	Distribution Charge		[1]	$ 0.2098629	$ 20.99		$ 0.2233773	$ 22.34		$ 1.35	6.43%
16	Transmission Charge		[1]	$ 0.1242724	$ 12.43		$ 0.1322751	$ 13.23		$ 0.80	6.44%
17	Storage Charge		[1]	$ 0.0378218	$ 3.78		$ 0.0402574	$ 4.03		$ 0.25	6.61%
18	Gas Supply Charge			$ 0.2544100	$ 25.44		$ 0.2738823	$ 27.39		$ 1.95	7.67%
19	DBU GTAC Amortization			$ 0.0000203	$ -		$ 0.0000203	$ -		$ -	0.00%
20	TBU GTAC Amortization			$ (0.0014935)	$ (0.15)		$ (0.0014935)	$ (0.15)		$ -	0.00%
21	Storage GTAC Amortization			$ -	$ -		$ -	$ -		$ -	0.00%
22	USBC			$ 0.0127763	$ 1.28		$ 0.0127763	$ 1.28		$ -	0.00%
23	Total Commodity			$ 0.6376702	$ 63.77		$ 0.6810952	$ 68.12		$ 4.35	6.82%
24											
25	Total Bill (Price per therm Incl. Service Charge)				$ 71.06			$ 75.87		$ 4.81	6.77%
29	[1]Rates exclude the tax tracker deferred balance from Order 7451a.										

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of NorthWestern Energy's Application for Authority to Change and Establish Natural Gas Delivery Service and Production Rates in Docket D2016.9.68 has been hand delivered to the Montana Public Service Commission and Montana Consumer Counsel and also e-filed with the Montana Public Service Commission this date. It has also been served upon the following persons by postage prepaid via first class mail as follows:

Robert Nelson
Montana Consumer Counsel
PO Box 201703
Helena MT 59620-1703

Pat Corcoran
NorthWestern Energy
11 East Park
Butte MT 59701

Joe Schwartzenberger
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Butte MT 59701

Charles Magraw
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Helena MT 59601

Thorvald A. Nelson
Holland & Hart
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Helena MT 59601

Terry Wisner
Jefferson Energy Trading LLC
65 E. Broadway Suite 303
Butte MT 59701

Amy Gold
Shell Energy North America (US) L.P.
1000 Main Street, Level 12
Houston TX 77002

DATED this 30th day of September 2016.

Connie Moran

Connie Moran
Administrative Assistant

MARKED-UP TARIFFS

Schedule No. D-GSGCA-1

DISTRIBUTION BUSINESS UNIT
GENERAL SERVICE GAS CORE AGGREGATION

APPLICABILITY: Applicable to commercial, industrial, multiple apartment buildings containing two or more dwelling units served through one meter, and other nonresidential core service, being served under the Core Aggregation Gas Transportation Program (Program) in all territory served by the Utility Distribution Business Unit (Utility).

AVAILABILITY: Available to general service customer loads, aggregated in accordance with Rate Schedule No. AGCT-1 and as is administratively feasible for the Utility.

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour			Per Meter Charge	
0	to	300	~~$ 19.15~~	$ 20.15
301	to	1,000	~~$ 25.25~~	$ 26.60
1,001	to	2,000	~~$ 40.70~~	$ 42.85
2,001	to	5,000	~~$ 68.30~~	$ 71.95
5,001	to	10,000	~~$ 83.95~~	$ 88.40
10,001	to	30,000	~~$ 132.65~~	$ 139.75
>30,000			~~$ 161.20~~	$ 169.80

PLUS:

Commodity Charges (Monthly $/Therm)	All Therms @	
Distribution Charge	~~$ 0.2050814~~	$ 0.2159598
Transmission Charge	~~0.1214186~~	0.1278535
Storage Charge	~~0.0368699~~	0.0388240
DBU GTAC Amortization		0.0000215
TBU GTAC Amortization		(0.0015870)
Storage GTAC Amortization		0.0000000
Total Rate	~~$ 0.3618044~~	$ 0.3810718

PLUS:

OTHER APPLICABLE CHARGES: All charges contained on other applicable rate schedules approved by the Public Service Commission of Montana.

(continued)

Schedule No. D-FTG-1

DISTRIBUTION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

APPLICABILITY: Applicable to Shippers for firm transportation service on the Utility Distribution System under the terms of a Gas Transportation Service Agreement (Agreement) between the Utility Distribution Business Unit (Utility) and Shipper and as subject to Rate Schedule General Terms and Operating Conditions (Rate Schedule GTC-1).

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge
2,000 to 5,000	~~$ 123.65~~ $ 130.25
5,000 to 10,000	~~$ 141.30~~ $ 148.85
10,001 to 30,000	~~$ 194.20~~ $ 204.60
>30,000	~~$ 225.60~~ $ 237.65

PLUS:

Distribution Charge: ($/MDDQ)	Maximum
Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	~~$ 0.7821585~~ $ 0.8238420
GTAC Amortization (MDDQ)	$ 0.0001412

MINIMUM BILL: Per respective contracts.

PAYMENT: Billed amounts shall be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate Schedule No. SGS-1.

APPLICATION OF RATES:

Monthly Bill Components: Each month, Shipper's bill shall consist of a Monthly Service Charge and a Reservation Charge.

I. Monthly Service Charge: The Monthly Service Charge shall be the product of the number of delivery meters at Shipper's facility times the applicable Meter Charge(s) set forth above under RATES. If Shipper receives service under more than one rate schedule through a single meter, only one Service Charge per meter per month shall apply.

(continued)

Schedule No. D-ITG-1

DISTRIBUTION BUSINESS UNIT
INTERRUPTIBLE TRANSPORTATION NATURAL GAS SERVICE

APPLICABILITY: Applicable to Shippers for interruptible transportation service on the Utility Distribution System under the terms of an Interruptible Gas Transportation Service Agreement (Agreement) between the Utility Distribution Business Unit (Utility) and Shipper and as subject to Rate Schedule General Terms and Operating Conditions (Rate Schedule GTC-1).

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge	
2,000 to 5,000	~~$ 123.65~~	$ 130.25
5,000 to 10,000	~~$ 141.30~~	$ 148.85
10,001 to 30,000	~~$ 194.20~~	$ 204.60
>30,000	~~$ 225.60~~	$ 237.65

PLUS:

Distribution Charge: (Monthly Rate per Therm):	Maximum	Minimum
Distribution Commodity Rate	~~$ 0.0257178~~ $ 0.0270884	$ 0.0017935

MINIMUM BILL: Per respective contracts.

PAYMENT: Billed amounts shall be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate Schedule No. SGS-1.

APPLICATION OF RATES:

Monthly Bill Components: Each month, Shipper's bill shall include a Monthly Service Charge and an Interruptible Distribution Commodity Charge for the actual quantities of natural gas delivered for Shipper.

1. Monthly Service Charge: The Monthly Service Charge shall be the product of the number of delivery meters at Shipper's facility times the applicable Meter Charge(s) set forth above. If Shipper receives service under more than one rate schedule through a single meter, only one service charge per meter per month shall apply.

2. Commodity Charge: The Monthly Commodity Charge shall be the produce of the actual monthly quantities of gas delivered to Shipper at Shipper's Point(s) of Delivery times the Maximum Distribution Commodity Rate set forth above, unless otherwise negotiated between the Utility and Shipper.

(continued)

Schedule No. T-FUGC-1

TRANSPORTATION BUSINESS UNIT
FIRM UTILITY GAS CONTRACT SERVICE

APPLICABILITY: Applicable to natural gas utilities receiving service as of November 1, 1991 for Firm Utility Gas Contract Sales Service provided under terms and conditions of contracts with the Utility Transportation Business Unit (Utility) as approved by the Montana Public Service Commission.

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge
10,001 to 30,000	~~$ 129.15~~ $ 136.05
>30,000	~~$ 332.85~~ $ 350.70

PLUS:
Transmission Charges:

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	~~$ 0.6286104/MDDQ~~ $ 0.6621116/MDDQ
Transmission Commodity Rate	~~$ 0.0074928/Therm~~ $ 0.0078922/Therm
GTAC Amortization	$ (0.0014680)/Therm

PLUS:
Storage Charges:

Maximum Monthly Reservation Rate for Maximum Storage (MDDQ)	~~$ 0.4999428/MDDQ~~ $ 0.5265869/MDDQ
Storage Commodity Rate	~~$ 0.0018085/Therm~~ $ 0.0019050/Therm
Storage GTAC Amortization	$ 0.0000000/MDDQ

PLUS:
Gas Supply Charges:

Gas Supply Charge	~~$ 0.2544100/Therm~~ $ 0.2738823/Therm
Deferred Gas Cost Amortization	$ 0.0000000/Therm

PLUS:

OTHER APPLICABLE CHARGES: All charges contained on other applicable rate schedules approved by the Public Service Commission of Montana.

(continued)

Schedule No. T-FTG-1

TRANSPORTATION BUSINESS UNIT
FIRM TRANSPORTATION NATURAL GAS SERVICE

APPLICABILITY: Applicable to Shippers for firm transportation service on the Utility Transmission System under the terms of a Firm Gas Transportation Service Agreement (Agreement) between the Utility Transportation Business Unit (Utility) and Shipper and as subject to Rate Schedule General Terms and Operating Conditions (Rate Schedule GTC-1).

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge
5,001 to 10,000	~~$ 120.95~~ $ 127.45
10,001 to 30,000	~~$ 173.90~~ $ 183.20
>30,000	~~$ 385.85~~ $ 406.50

PLUS:

Transmission Reservation Rate (Monthly Rate per MDDQ):

Maximum Monthly Reservation Rate for Maximum Daily Delivery Quantity (MDDQ)	~~$ 0.9887752~~ $ 1.0414710

Transmission Commodity Rate (Monthly Rate per Therm):

Maximum	~~$ 0.0074928~~ $ 0.0078922
Minimum	$ 0.0017935
GTAC Amortization	$ (0.0007528)
Balancing Penalty Rate	Higher of $25.00/ Dekatherm Or 150% of Market Price

PLUS:

OTHER APPLICABLE CHARGES: All charges contained on other applicable rate schedules approved by the Public Service Commission of Montana.

GAS TRANSPORTATION ADJUSTMENT CLAUSE: Pursuant to MPSC Order the above GTAC Amortization shall be in effect until the balance is extinguished.

MINIMUM BILL: Per respective contracts.

(continued)

Schedule No. T-ITG-1

TRANSPORTATION BUSINESS UNIT
INTERRUPTIBLE TRANSPORTATION NATURAL GAS SERVICE

APPLICABILITY: Applicable to Shippers for interruptible transportation service on the Utility Transmission System under the terms of an Interruptible Gas Transportation Service Agreement (Agreement) between the Utility Transportation Business Unit (Utility) and Shipper and as subject to Rate Schedule General Terms and Operating Conditions (Rate Schedule GTC-1).

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour	Per Meter Charge
5,001 to 10,000	~~$ 120.95~~ $ 127.45
10,001 to 30,000	~~$ 173.90~~ $ 183.20
>30,000	~~$ 385.85~~ $ 406.50

PLUS:

Transmission Charge: (Monthly Rate per Therm):	Maximum	Minimum
Transmission Commodity Rate	~~$ 0.0392441~~ $ 0.0421286	$ 0.0017935
Balancing Penalty Rate	Higher of $25.00/dekatherm or 150% of Market Price.	
Unauthorized System Use Rate	$ 25.00	$ 25.00

MINIMUM BILL: Per respective contracts.

PLUS:

OTHER APPLICABLE CHARGES: All charges contained on other applicable rate schedules approved by the Public Service Commission of Montana.

PAYMENT: Billed amounts shall be considered past due if not paid by the due date shown on the bill. Past due bills are subject to a late payment charge in accordance with the provisions of Rate Schedule No. SGS-1.

(continued)

Schedule No. T-FSG-1

TRANSPORTATION BUSINESS UNIT
FIRM STORAGE NATURAL GAS SERVICE

APPLICABILITY: Applicable to Shippers for Firm Storage Service under the terms of a Firm Gas Storage Service Agreement (Agreement) between the Utility Transportation Business Unit (Utility) and the Shipper and as subject to Rate Schedule General Terms and Operating Conditions (Rate Schedule GTC-1).

RATES: Net Monthly Bill:

Monthly Rate:

Withdrawal Reservation Rate:	$	~~0.4726131~~	0.4976737	/MDDQ
Injection Commodity Rate:	$	~~0.0024423~~	0.0025719	/Therm
Withdrawal Commodity Rate:	$	~~0.0024423~~	0.0025719	/Therm
Storage Capacity Rate:	$	~~0.0023203~~	0.0024433	/Therm
GTAC Amortization	$	0.0000000		/MDDQ

APPLICATION OF RATES:

Monthly Bill Components: Each month, Shipper's bill shall include a Withdrawal Reservation Charge and, if applicable, an Injection Commodity Charge for the quantities of natural gas nominated by Shipper and received by Utility for injection into storage, a Withdrawal Commodity Charge for the quantities of natural gas nominated by Shipper and delivered by Utility from storage for Shipper's account and a Storage Capacity Charge.

1. Withdrawal Reservation Charge: The Monthly Withdrawal Reservation Charge shall be the product of the Shipper's Storage Maximum Daily Delivery Quantity (MDDQ) as set forth in the Agreement times the applicable rate set forth above.

2. Injection Commodity Charge: The Monthly Injection Commodity Charge shall be the product of the Shipper's nominated quantities of natural gas received by the Utility for injection into storage times the applicable rate set forth above.

3. Withdrawal Commodity Charge: The Monthly Withdrawal Commodity Charge shall be the produce of the Shipper's nominated quantities of natural gas delivered by the Utility from storage times the applicable rate set forth above.

4. Storage Capacity Charge: The Monthly Storage Capacity Charge shall be the product of the Shipper's storage balance at the end of the month times the applicable rate set forth above.

5. Discounting Rates: The Utility shall have the ability to discount the Monthly Withdrawal Reservation Rate set forth above if the Shipper can demonstrate that, as a direct result of the

(continued)

Schedule No. D-RG-1

DISTRIBUTION BUSINESS UNIT
RESIDENTIAL NATURAL GAS SERVICE

APPLICABILITY: Applicable to residential service, including single family dwellings and single family living units which are individually metered, in all territory served by the Utility Distribution Business Unit (Utility).

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:	~~$ 7.35~~ $ 7.75

PLUS:

Commodity Charges (Monthly $/Therm)	All Therms @
Distribution Charge	~~$ 0.2121070~~ $ 0.2233773
Transmission Charge	~~0.1256012~~ 0.1322751
Storage Charge	~~0.0382262~~ 0.0402574
Gas Supply Charge	~~0.2544100~~ 0.2738823
Deferred Gas Cost Amortization	0.0000000
DBU GTAC Amortization	0.0000203
TBU GTAC Amortization	(0.0014935)
Storage GTAC Amortization	0.0000000
Total Rate	~~$ 0.6288712~~ $ 0.6683189

PLUS:

OTHER APPLICABLE CHARGES: All charges contained on other applicable rate schedules approved by the Public Service Commission of Montana.

LOW INCOME DISCOUNT: Customers of the Utility shall obtain a thirty percent (30%) discount during November 1st to April 30th from the above Regular Customer Rate(s) for residential usage, if they have satisfied the requirements for and are receiving energy assistance through the LIEAP program administered by the State of Montana Department of Public Health and Human Services.

(continued)

Schedule No. D-RGCA-1

DISTRIBUTION BUSINESS UNIT
RESIDENTIAL GAS CORE AGGREGATION SERVICE

APPLICABILITY: Applicable to residential service, including single family dwellings and single family living units which are individually metered, being served under the Core Aggregation Gas Transportation Program (Program) in all territory served by the Utility Distribution Business Unit (Utility).

AVAILABILITY: Available to residential service customer loads, aggregated in accordance with Rate Schedule No. AGCT-1 and as is administratively feasible for the Utility.

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:	~~$ 7.35~~ $ 7.75

PLUS:

Commodity Charges (Monthly $/Therm)	All Therms @
Distribution Charge	~~$ 0.2121070~~ $ 0.2233773
Transmission Charge	~~0.1256012~~ 0.1322751
Storage Charge	~~0.0382262~~ 0.0402574
DBU GTAC Amortization	0.0000203
TBU GTAC Amortization	(0.0014935)
Storage GTAC Amortization	0.0000000
Total Rate	~~$ 0.3744612~~ $ 0.3944366

PLUS:

OTHER APPLICABLE CHARGES: All charges contained on other applicable rate schedules approved by the Public Service Commission of Montana.

LOW INCOME DISCOUNT: Customers of the Utility who obtained a fifteen percent (15%) discount under Rate Schedule No. D-RG-1 shall obtain a twenty-three percent (23%) discount from the above rates for residential usage, if they have satisfied the requirements for and are receiving energy assistance through the LIEAP program administered by the State of Montana Department of Public Health and Human Services.

DEFERRED GAS COST: Pursuant to MPSC Order the above Deferred Gas Cost Amortization shall be in effect until the balance is extinguished.

GAS TRANSPORTATION ADJUSTMENT CLAUSE: Pursuant to MPSC Order the above GTAC Amortization shall be in effect until the balance is extinguished.

(continued)

Schedule No. D-GSG-1

DISTRIBUTION BUSINESS UNIT
GENERAL NATURAL GAS SERVICE

APPLICABILITY: Applicable to commercial, industrial, multiple apartment buildings containing two or more dwelling units served through one meter, and other nonresidential core service in all territory served by the Utility Distribution Business Unit (Utility).

RATES: Net Monthly Bill:

Monthly Service Charge per Meter:

Meters Rated @ Cu. Ft. per hour			Per Meter Charge	
0	to	300	~~$ 19.15~~	$ 20.15
301	to	1,000	~~$ 25.25~~	$ 26.60
1,001	to	2,000	~~$ 40.70~~	$ 42.85
2,001	to	5,000	~~$ 68.30~~	$ 71.95
5,001	to	10,000	~~$ 83.95~~	$ 88.40
10,001	to	30,000	~~$ 132.65~~	$ 139.75
>30,000			~~$ 161.20~~	$ 169.80

PLUS:

Commodity Charges (Monthly $/Therm)	All Therms @	
Distribution Charge	~~$ 0.2050814~~	$ 0.2159598
Transmission Charge	~~0.1214186~~	0.1278535
Storage Charge	~~0.0368699~~	0.0388240
Gas Supply Charge	~~0.2544100~~	0.2738823
Deferred Gas Cost Amortization		0.0000000
DBU GTAC Amortization		0.0000215
TBU GTAC Amortization		(0.0015870)
Storage GTAC Amortization		0.0000000
Total Rate	~~$ 0.6162144~~	$ 0.6354818

PLUS:

OTHER APPLICABLE CHARGES: All charges contained on other applicable rate schedules approved by the Public Service Commission of Montana.

DEFERRED GAS COST: Pursuant to MPSC Order the above Deferred Gas Cost Amortization shall be in effect until the balance is extinguished.

GAS TRANSPORTATION ADJUSTMENT CLAUSE: Pursuant to MPSC Order the above GTAC Amortization shall be in effect until the balance is extinguished.

(continued)

Changes are proposed for the following two additional tariffs in this filing:

- Schedule No. GTC-1 On System General Terms and Operating Conditions; and
- Schedule No. AGTC-1 Aggregation General Terms and Operating Conditions.

The Prefiled Direct Testimony of John S. Canavan explains these proposed changes, and his accompanying exhibits are clean and redline versions of both tariffs.

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

IN THE MATTER of NorthWestern Energy's Application for Approval to Change and Establish Natural Gas Delivery Service and Production Rates	))))	REGULATORY DIVISION DOCKET NO. D2016.9.68

NOTICE OF INTERIM RATE ADJUSTMENT REQUEST

NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern" or "Applicant") serves notice pursuant to the Administrative Rules of Montana, Section 38.5.503, that it has filed with the Montana Public Service Commission ("Commission") a request for an overall interim increase in Natural Gas delivery rates and decrease in production rates relating to the Battle Creek Natural Gas production assets in the above-captioned docket. The Interim request for the Natural Gas delivery service is $5,596,577 and production is a decrease of $22,455. This Notice is based on the Application and the workpapers in this docket.

This docket commenced on September 30, 2016, when the Applicant filed prefiled direct testimony, exhibits, and supporting workpapers with the Commission. Pursuant to § 69-3-304, MCA, Applicant requests an interim increase in delivery rates and decrease in production rates to be implemented pending a final decision in this docket.

This request for interim adjustment to Natural Gas Utility service rates was made because the rates presently in effect are no longer just and reasonable rates as they do not allow NorthWestern an opportunity to recover in rates its cost of providing Natural Gas service to its customers. This is demonstrated in the prefiled direct testimony, exhibits, and supporting

workpapers included in Applicant's filing in this docket.

The interim Natural Gas service rates have been calculated based upon adjustments, methodologies, and rates of return resulting from NorthWestern's last applicable general rate case – Docket No. D2012.9.94 for the Natural Gas Utility. Rates implementing the requested interim increases and decreases are shown in the Interim Section of Applicant's filing. Delivery service rates are increased on a uniform percentage basis for all classes. Production rates are decreased on a uniform percentage basis for all core customer classes. Applicant submits that the interests of the Applicant's customers are fully protected during the period the interim increase is in effect by the rebate provision found in § 69-3-304, MCA.

The interim request and supporting documents can be examined at NorthWestern's General Office, 11 East Park, Butte, Montana; at the office of the Montana Consumer Counsel ("MCC"), 111 North Last Chance Gulch, Suite 1B, Helena, Montana; or at the office of the Commission, 1701 Prospect Avenue, Helena, Montana. The MCC is available to assist in the representation of consumer interests in this matter, and its phone number is 406-444-2771.

Any response which any person wishes to have the Commission take into consideration in its decision on this interim rate relief matter should be delivered to the Commission at the above address as soon as possible or mailed to the Commission at P.O. Box 202601, Helena, MT 59620-2601.

Any portion of the interim adjustment approved by the Commission pending hearing and final decision would, pursuant to § 69-3-304, MCA, be subject to rebate or surcharge if the final decision in this docket is to approve a final rate which is different than the interim rate.

Dated: September 30, 2016.

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

In the Matter of NorthWestern Energy's Application for Approval to Change and Establish Natural Gas Delivery Service and Production Rates	))))	Docket No. D2016.9.68

CERTIFICATE OF SERVICE
OF NOTICE OF INTERIM RATE ADJUSTMENT REQUEST
FOR NATURAL GAS DELIVERY SERVICE AND CERTAIN PRODUCTION RATES

The undersigned certifies that a Notice of Interim Rate Adjustment Request was this day served by mail upon the following:

Daily Newspapers

Montana Standard	Helena Independent Record
Missoulian	Billings Gazette
Great Falls Tribune	Livingston Enterprise
Bozeman Chronicle	Ravalli Republic
Daily Inter Lake	Havre Daily News

Associated Press Print and Broadcast Services

Television Stations

Billings	KTVQ and KULR
Butte	KXLF
Missoula/Kalispell	KECI and KPAX
Great Falls	KFBB and KRTV
Bozeman	KTVM
Helena	KTVH

DATED: September 30, 2016

NorthWestern Energy

By: Claudia Rapkoch

Claudia Rapkoch
11 East Park
Butte, Montana 59701

NorthWestern Energy
Natural Gas Utility
Interim Filing

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1	**NORTHWESTERN ENERGY**					
2	**NATURAL GAS TRANSMISSION, DISTRIBUTION & STORAGE UTILITY**					
3	**INCOME STATEMENT**					
4	**ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED**					
5						
6						
7		TD&S	BATTLE CREEK	BEAR PAW	SOUTH BEAR PAW	TOTAL
8						
9	REVENUES:					
10	RATE SCHEDULE REVENUES	92,735,539	2,333,679	0	0	95,069,217
11	SALES FOR RESALE	330,096	62,546	0	0	392,642
12	PROVISION FOR RATE REFUNDS	0	0	0	0	0
13	TRANSPORTATION	21,594,917	0	0	0	21,594,917
14	MISCELLANEOUS REVENUES	613,520	115,677	0	0	729,197
15	GROSS REVENUES (LINE 10 THRU 14)	115,274,072	2,511,901	0	0	117,785,973
16						
17	COST OF SERVICE:					
18	PRODUCTION & GATHERING OPERATION	0	543,655	0	0	543,655
19	PRODUCTION & GATHERING MAINTENANCE	0	10,809	0	0	10,810
20	GAS SUPPLY	503,955	0	0	0	503,955
21	STORAGE OPERATION	1,055,284	0	0	0	1,055,284
22	STORAGE MAINTENANCE	359,422	0	0	0	359,422
23	TRANSMISSION OPERATION	7,766,588	0	0	0	7,766,588
24	TRANSMISSION MAINTENANCE	2,356,898	0	0	0	2,356,898
25	DISTRIBUTION OPERATION	10,996,148	9,466	0	0	11,005,614
26	DISTRIBUTION MAINTENANCE	3,508,730	0	0	0	3,508,730
27	CUSTOMER ACCOUNTS EXPENSE	3,346,775	39,693	0	0	3,386,467
28	CUSTOMER SERVICE AND INFORMATION EXPENSE	1,510,184	39,857	0	0	1,550,041
29	SALES EXPENSE	(0)	0	0	0	(0)
30	ADMINISTRATIVE AND GENERAL EXPENSE	16,245,020	483,284	0	0	16,728,305
31	TOTAL O & M EXPENSE (LINE 18 THRU 30)	47,649,005	1,126,765	0	0	48,775,770
32						
33	DEPRECIATION	14,859,476	64,059	0	0	14,923,536
34	AMORTIZATION OF NATURAL GAS PLANT / DEPLETION	1,250,806	498,089	0	0	1,748,895
35	* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN	(420,516)	0	0	0	(420,516)
36	* AMORTIZATION RE:PROPERTY TAXES	0	0	0	0	0
37	* AMORTIZATION RE:USBC	0	0	0	0	0
38	* AMORTIZATION RE:COMPENSATED ABSENCES	0	0	0	0	0
39	* AMORTIZATION RE:	0	0	0	0	0
40	* AMORTIZATION RE:	0	0	0	0	0
41	* AMORTIZATION RE:NG MPSC/MCC TAXES	108,296	(232)	0	0	108,063
42	* PENSION DIFFERENTIAL	(2,554,220)	(54,354)	0	0	(2,608,574)
43	TAXES OTHER THAN INCOME TAXES	33,975,479	67,971	0	0	34,043,450
44	INCOME TAXES - FEDERAL - U.S.	1	0	0	0	1
45	INCOME TAXES - OTHER	0	0	0	0	0
46	DEFERRED INCOME TAXES	(1,706,001)	186,244	0	0	(1,519,757)
47	SUBTOTAL (LINE 33 THRU 46)	45,513,321	761,777	0	0	46,275,098
48						
49	TOTAL COST OF SERVICE (LINE 31 + 47)	93,162,326	1,888,542	0	0	95,050,868
50						
51	UTILITY OPERATING INCOME (LINE 15 - 49)	22,111,745	623,359	0	0	22,735,105
52						
53	NATURAL GAS UTILITY RATE BASE	359,990,736	8,613,199	0	0	368,603,936
54	RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)	6.14%	7.24%	0.00%	0.00%	6.17%
55						
56	REQUIRED REVENUE INCREASE	5,596,577	(22,455)	0	0	5,574,122

	A	B	C	D	E	F	G	H
1		**NORTHWESTERN ENERGY**						
2		**NATURAL GAS TRANSMISSION, DISTRIBUTION & STORAGE UTILITY**						
3		**INCOME STATEMENT**						
4		**ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED**						
5					NATURAL GAS	REVENUE	SALES &	
6					TRANSMISSION,	& REVENUE	ADMINISTRATIVE	
7			NATURAL GAS	SUPPLY	DISTRIBUTION &	RELATED	& GENERAL	LABOR
8			UTILITY	FUNCTION	STORAGE UTILITY	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT
9		REVENUES:						
10		RATE SCHEDULE REVENUES	$150,261,562	($60,916,108)	$89,345,454	$3,390,085		
11		SALES FOR RESALE	1,162,945	(836,575)	326,370	3,726		
12		PROVISION FOR RATE REFUNDS	(890,160)	890,160	(0)	0		
13		TRANSPORTATION	23,586,269	(1,616,260)	21,970,009	(375,092)		
14		MISCELLANEOUS REVENUES	2,289,464	(1,139,640)	1,149,824	(536,304)		
15		GROSS REVENUES (LINE 10 THRU 14)	$176,410,080	($63,618,423)	$112,791,657	$2,482,415	$0	$0
16								
17		COST OF SERVICE:						
18		PRODUCTION & GATHERING OPERATION	10,383,709	($10,383,709)	$0			0
19		PRODUCTION & GATHERING MAINTENANCE	514,660	(514,660)	0			0
20		GAS SUPPLY	35,068,658	(34,592,753)	475,905			$28,050
21		STORAGE OPERATION	1,040,696	-	1,040,696			$14,588
22		STORAGE MAINTENANCE	354,669	-	354,669			$4,753
23		TRANSMISSION OPERATION	7,608,824	-	7,608,824			$157,764
24		TRANSMISSION MAINTENANCE	2,293,797	-	2,293,797			$63,101
25		DISTRIBUTION OPERATION	11,080,587	(56,914)	11,023,673			($13,396)
26		DISTRIBUTION MAINTENANCE	3,468,704	-	3,468,704			$40,026
27		CUSTOMER ACCOUNTS EXPENSE	3,468,625	(242,803)	3,225,822	150,410	(20,260)	$34,813
28		CUSTOMER SERVICE AND INFORMATION EXPENSE	1,721,161	(236,150)	1,485,011		0	$39,112
29		SALES EXPENSE	151,001	(34,713)	116,288		(116,288)	$0
30		ADMINISTRATIVE AND GENERAL EXPENSE	23,350,351	(2,753,240)	20,597,111	(3,327,005)	(323,025)	$71,595
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	100,505,442	(48,814,942)	51,690,500	($3,176,595)	($459,573)	$440,406
32								
33		DEPRECIATION	15,396,572	(529,375)	14,867,197			
34		AMORTIZATION OF NATURAL GAS PLANT	7,699,240	(6,448,434)	1,250,806			
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN	(420,516)	-	(420,516)			
36		* AMORTIZATION RE:PROPERTY TAXES	(1,046,934)	-	(1,046,934)			
37		* AMORTIZATION RE:USBC	(1,352,578)	-	(1,352,578)			
38		* AMORTIZATION RE:COMPENSATED ABSENCES	-	-	-			
39		* AMORTIZATION RE:	-	-	-			
40		* AMORTIZATION RE:	-	-	-			
41		* AMORTIZATION RE:NG MPSC/MCC TAXES	173,472	(24,288)	149,184			
42		* PENSION DIFFERENTIAL	(2,411,149)	332,572	(2,078,577)			
43		TAXES OTHER THAN INCOME TAXES	29,666,502	(1,388,688)	28,277,814	233,198		30,902
44		INCOME TAXES - FEDERAL - U.S.	(1,004,923)	1,592,193	587,270	0	0	0
45		INCOME TAXES - OTHER	(200,598)	334,820	134,222	0	0	0
46		DEFERRED INCOME TAXES	3,298,178	(3,232,876)	65,302	2,137,091	181,014	(185,636)
47		SUBTOTAL (LINE 33 THRU 46)	49,797,265	(9,364,076)	40,433,190	$2,370,289	$181,014	($154,734)
48								
49		TOTAL COST OF SERVICE (LINE 31 + 47)	150,302,707	(58,179,017)	92,123,690	($806,306)	($278,559)	$285,672
50								
51		UTILITY OPERATING INCOME (LINE 15 - 49)	26,107,373	(5,439,406)	20,667,967	$3,288,720	$278,559	($285,672)
52								
53		NATURAL GAS UTILITY RATE BASE	$444,875,429	(73,577,215)	$371,298,214	$0	$0	$0
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)			5.57%			
55								
56		REQUIRED REVENUE INCREASE			$10,856,569	($5,452,529)	($461,836)	$473,629
57								
58								
59								

	A	B	I	J	K	L	M	N	O
1		NORTHWESTERN ENERGY							
2		NATURAL GAS TRANSMISSION, DISTRIBUTION & STORAGE UTILITY							
3		INCOME STATEMENT							
4		ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED							
5									
6				CORPORATE	STIPULATION AND		TAXES - OTHER		WORKING
7			ONE-TIME	ALLOCATION	MARKET CREDITS	AMORTIZATION	THAN INCOME	DEPRECIATION	CAPITAL
8			ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT
9		REVENUES:							
10		RATE SCHEDULE REVENUES							
11		SALES FOR RESALE							
12		PROVISION FOR RATE REFUNDS							
13		TRANSPORTATION							
14		MISCELLANEOUS REVENUES							
15		GROSS REVENUES (LINE 10 THRU 14)	$0	$0	$0	$0	$0	$0	$0
16									
17		COST OF SERVICE:							
18		PRODUCTION & GATHERING OPERATION							
19		PRODUCTION & GATHERING MAINTENANCE							
20		GAS SUPPLY							
21		STORAGE OPERATION							
22		STORAGE MAINTENANCE							
23		TRANSMISSION OPERATION							
24		TRANSMISSION MAINTENANCE							
25		DISTRIBUTION OPERATION		(14,129)					
26		DISTRIBUTION MAINTENANCE							
27		CUSTOMER ACCOUNTS EXPENSE	10,087	(54,097)					
28		CUSTOMER SERVICE AND INFORMATION EXPENSE		(13,939)					
29		SALES EXPENSE		0					
30		ADMINISTRATIVE AND GENERAL EXPENSE		(773,655)					
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	$10,087	($855,820)	$0	$0	$0	$0	$0
32									
33		DEPRECIATION						$250,691	
34		AMORTIZATION OF NATURAL GAS PLANT							
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN							
36		* AMORTIZATION RE:PROPERTY TAXES				1,046,934			
37		* AMORTIZATION RE:USBC				1,352,578			
38		* AMORTIZATION RE:COMPENSATED ABSENCES				0			
39		* AMORTIZATION RE:				0			
40		* AMORTIZATION RE:				0			
41		* AMORTIZATION RE:NG MPSC/MCC TAXES				(40,888)			
42		* PENSION DIFFERENTIAL				(475,643)			
43		TAXES OTHER THAN INCOME TAXES					5,433,565		
44		INCOME TAXES - FEDERAL - U.S.	0	0	0	0	0	0	0
45		INCOME TAXES - OTHER	0	0	0	0	0	0	0
46		DEFERRED INCOME TAXES	(3,973)	337,086	0	(659,043)	(2,140,145)	(87,742)	0
47		SUBTOTAL (LINE 33 THRU 46)	($3,973)	$337,086	$0	$1,223,938	$3,293,420	$162,949	$0
48									
49		TOTAL COST OF SERVICE (LINE 31 + 47)	$6,114	($518,734)	$0	$1,223,938	$3,293,420	$162,949	$0
50									
51		UTILITY OPERATING INCOME (LINE 15 - 49)	($6,114)	$518,734	$0	($1,223,938)	($3,293,420)	($162,949)	$0
52									
53		NATURAL GAS UTILITY RATE BASE	$0	$0	($10,456,297)	$163,570	$0	($129,206)	($2,241,586)
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)							
55									
56		REQUIRED REVENUE INCREASE	$10,137	($860,034)	($1,270,730)	$2,049,106	$5,460,321	$254,458	($272,414)
57									
58									
59									

	A	B	P	Q	R	S	T	U
1		NORTHWESTERN ENERGY						
2		NATURAL GAS TRANSMISSION, DISTRIBUTION & STORAGE UTILITY						
3		INCOME STATEMENT						
4		ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED						
5							10.35%	
6				INTEREST	TOTAL	TEST PERIOD	ADJUST TO	
7			INCOME TAX	SYNCHRONIZATION	UPDATES &	@ PRESENT	ROE FROM	DEPRECIATION
8			ADJUSTMENT	ADJUSTMENT	ADJUSTMENTS	RATES	D2012.9.94	ADJUSTMENT
9		REVENUES:						
10		RATE SCHEDULE REVENUES			$3,390,085	$92,735,539		
11		SALES FOR RESALE			3,726	330,096		
12		PROVISION FOR RATE REFUNDS			0	0		
13		TRANSPORTATION			(375,092)	21,594,917		
14		MISCELLANEOUS REVENUES			(536,304)	613,520		
15		GROSS REVENUES (LINE 10 THRU 14)	$0	$0	$2,482,415	$115,274,072	$0	$0
16								
17		COST OF SERVICE:						
18		PRODUCTION & GATHERING OPERATION			$0	$0		
19		PRODUCTION & GATHERING MAINTENANCE			0	0		
20		GAS SUPPLY			28,050	503,955		
21		STORAGE OPERATION			14,588	1,055,284		
22		STORAGE MAINTENANCE			4,753	359,422		
23		TRANSMISSION OPERATION			157,764	7,766,588		
24		TRANSMISSION MAINTENANCE			63,101	2,356,898		
25		DISTRIBUTION OPERATION			(27,525)	10,996,148		
26		DISTRIBUTION MAINTENANCE			40,026	3,508,730		
27		CUSTOMER ACCOUNTS EXPENSE			120,953	3,346,775		
28		CUSTOMER SERVICE AND INFORMATION EXPENSE			25,172	1,510,184		
29		SALES EXPENSE			(116,288)	(0)		
30		ADMINISTRATIVE AND GENERAL EXPENSE			(4,352,090)	16,245,020		
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	$0	$0	($4,041,495)	$47,649,005	$0	$0
32								
33		DEPRECIATION			$250,691	$15,117,887		($258,411)
34		AMORTIZATION OF NATURAL GAS PLANT			0	1,250,806		
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN			0	(420,516)		
36		* AMORTIZATION RE:PROPERTY TAXES			1,046,934	0		
37		* AMORTIZATION RE:USBC			1,352,578	0		
38		* AMORTIZATION RE:COMPENSATED ABSENCES			0	0		
39		* AMORTIZATION RE:			0	0		
40		* AMORTIZATION RE:			0	0		
41		* AMORTIZATION RE:NG MPSC/MCC TAXES			(40,888)	108,296		
42		* PENSION DIFFERENTIAL			(475,643)	(2,554,220)		
43		TAXES OTHER THAN INCOME TAXES			5,697,665	33,975,479		
44		INCOME TAXES - FEDERAL - U.S.	(587,269)	0	(587,269)	1	0	0
45		INCOME TAXES - OTHER	(134,222)	0	(134,222)	0	0	0
46		DEFERRED INCOME TAXES	(280,096)	(1,160,749)	(1,862,193)	(1,796,891)	0	90,444
47		SUBTOTAL (LINE 33 THRU 46)	($1,001,587)	($1,160,749)	$5,247,653	$45,680,842	$0	($167,967)
48								
49		TOTAL COST OF SERVICE (LINE 31 + 47)	($1,001,587)	($1,160,749)	$1,206,157	$93,329,847	$0	($167,967)
50								
51		UTILITY OPERATING INCOME (LINE 15 - 49)	$1,001,587	$1,160,749	$1,276,257	$21,944,224	$0	$167,967
52								
53		NATURAL GAS UTILITY RATE BASE	$1,401,486	$0	($11,262,033)	360,036,181		
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)				6.10%		
55								
56		REQUIRED REVENUE INCREASE	($1,490,260)	($1,924,462)	($3,484,614)	$7,371,955	($1,492,303)	($278,480)
57								
58								
59								

	A	B	V	W	X	Y	Z
1		NORTHWESTERN ENERGY					
2		NATURAL GAS TRANSMISSION, DISTRIBUTION & STORAGE UTILITY					
3		INCOME STATEMENT					
4		ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED	INTERIM ADJUSTMENTS				
5						INTERIM	INTERIM
6			WORKING		INTEREST	TOTAL	TEST PERIOD
7			CAPITAL	INCOME TAX	SYNCHRONIZATION	UPDATES &	@ PRESENT
8			ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENTS	RATES
9		REVENUES:					
10		RATE SCHEDULE REVENUES				0	$92,735,539
11		SALES FOR RESALE				0	330,096
12		PROVISION FOR RATE REFUNDS				0	0
13		TRANSPORTATION				0	21,594,917
14		MISCELLANEOUS REVENUES				0	613,520
15		GROSS REVENUES (LINE 10 THRU 14)	$0	$0	$0	$0	$115,274,072
16							
17		COST OF SERVICE:					
18		PRODUCTION & GATHERING OPERATION				0	0
19		PRODUCTION & GATHERING MAINTENANCE				0	0
20		GAS SUPPLY				0	503,955
21		STORAGE OPERATION				0	1,055,284
22		STORAGE MAINTENANCE				0	359,422
23		TRANSMISSION OPERATION				0	7,766,588
24		TRANSMISSION MAINTENANCE				0	2,356,898
25		DISTRIBUTION OPERATION				0	10,996,148
26		DISTRIBUTION MAINTENANCE				0	3,508,730
27		CUSTOMER ACCOUNTS EXPENSE				0	3,346,775
28		CUSTOMER SERVICE AND INFORMATION EXPENSE				0	1,510,184
29		SALES EXPENSE				0	0
30		ADMINISTRATIVE AND GENERAL EXPENSE				0	16,245,020
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	$0	$0	$0	$0	$47,649,005
32							
33		DEPRECIATION				-258,411	14,859,476
34		AMORTIZATION OF NATURAL GAS PLANT				0	1,250,806
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN				0	(420,516)
36		* AMORTIZATION RE:PROPERTY TAXES				0	0
37		* AMORTIZATION RE:USBC				0	0
38		* AMORTIZATION RE:COMPENSATED ABSENCES				0	0
39		* AMORTIZATION RE:				0	0
40		* AMORTIZATION RE:				0	0
41		* AMORTIZATION RE:NG MPSC/MCC TAXES				0	108,296
42		* PENSION DIFFERENTIAL				0	(2,554,220)
43		TAXES OTHER THAN INCOME TAXES				0	33,975,479
44		INCOME TAXES - FEDERAL - U.S.	0	0	0	0	1
45		INCOME TAXES - OTHER	0	0	0	0	0
46		DEFERRED INCOME TAXES	0	0	446	90,890	(1,706,001)
47		SUBTOTAL (LINE 33 THRU 46)	$0	$0	$446	($167,521)	$45,513,321
48							
49		TOTAL COST OF SERVICE (LINE 31 + 47)	$0	$0	$446	($167,521)	$93,162,326
50							
51		UTILITY OPERATING INCOME (LINE 15 - 49)	$0	$0	($446)	$167,521	$22,111,745
52							
53		NATURAL GAS UTILITY RATE BASE		($45,445)		($45,445)	$359,990,736
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)					6.14%
55							
56		REQUIRED REVENUE INCREASE	$0	($5,335)	$740	($1,775,378)	$5,596,577
57							
58							
59							

	A	B	C	D	E	F	G	H
1		**NORTHWESTERN ENERGY**						
2		**BATTLE CREEK**						
3		**INCOME STATEMENT**						
4		**ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED**						
5						REVENUE	SALES &	
6						& REVENUE	ADMINISTRATIVE	
7				BATTLE CREEK	BATTLE CREEK	RELATED	& GENERAL	LABOR
8			BATTLE CREEK	VARIABLE	FIXED	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT
9		REVENUES:						
10		RATE SCHEDULE REVENUES	$2,440,969		$2,440,969	($107,291)		
11		SALES FOR RESALE	59,528		59,528	3,018		
12		PROVISION FOR RATE REFUNDS	-		-	-		
13		TRANSPORTATION	-		-			
14		MISCELLANEOUS REVENUES	115,677		115,677	-		
15		GROSS REVENUES (LINE 10 THRU 14)	$2,616,174	$0	$2,616,174	($104,273)	$0	$0
16								
17		COST OF SERVICE:						
18		PRODUCTION & GATHERING OPERATION	639,043	114,263	524,781			6,375
19		PRODUCTION & GATHERING MAINTENANCE	11,572		11,572			84
20		GAS SUPPLY	(170,795)	(170,795)	-			0
21		STORAGE OPERATION	-		-			0
22		STORAGE MAINTENANCE	-		-			0
23		TRANSMISSION OPERATION	-		-			0
24		TRANSMISSION MAINTENANCE	-		-			0
25		DISTRIBUTION OPERATION	-		-			0
26		DISTRIBUTION MAINTENANCE	-		-			0
27		CUSTOMER ACCOUNTS EXPENSE	-		-			0
28		CUSTOMER SERVICE AND INFORMATION EXPENSE	-		-			0
29		SALES EXPENSE	-		-			0
30		ADMINISTRATIVE AND GENERAL EXPENSE	-		-		871	0
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	479,820	(56,533)	536,352	-	871	6,459
32								
33		DEPRECIATION	179,754		179,754			
34		DEPLETION	610,318		610,318			
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN	-		-			
36		* AMORTIZATION RE:PROPERTY TAXES	-		-			
37		* AMORTIZATION RE:USBC	-		-			
38		* AMORTIZATION RE:COMPENSATED ABSENCES	-		-			
39		* AMORTIZATION RE:	-		-			
40		* AMORTIZATION RE:	-		-			
41		* AMORTIZATION RE:NG MPSC/MCC TAXES	-		-			
42		* PENSION DIFFERENTIAL	-		-			
43		TAXES OTHER THAN INCOME TAXES	121,717	61,465	60,251	$1,828		452
44		INCOME TAXES - FEDERAL - U.S.	(658,360)		(658,360)	0	0	0
45		INCOME TAXES - OTHER	(136,160)		(136,160)	0	0	0
46		DEFERRED INCOME TAXES	1,180,451	(1,943)	1,182,394	(41,790)	(343)	(2,722)
47		SUBTOTAL (LINE 33 THRU 46)	1,297,720	59,522	1,238,198	(39,962)	(343)	(2,270)
48								
49		TOTAL COST OF SERVICE (LINE 31 + 47)	1,777,540	2,990	1,774,550	(39,962)	528	4,189
50								
51		UTILITY OPERATING INCOME (LINE 15 - 49)	838,634	(2,990)	841,624	(64,311)	(528)	(4,189)
52								
53		NATURAL GAS UTILITY RATE BASE	$8,579,130		$8,579,130			
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)	9.78%		9.81%			
55								
56		REQUIRED REVENUE INCREASE			($352,769)	$106,625	$875	$6,946

	A	B	I	J	K	L	M	N
1		**NORTHWESTERN ENERGY**						
2		**BATTLE CREEK**						
3		**INCOME STATEMENT**						
4		**ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED**						
5								
6				DEPRECIATION		ALLOCATION OF	TAXES - OTHER	WORKING
7			ONE-TIME	AND DEPLETION	AMORTIZATION	GAS PRODUCTION	THAN INCOME	CAPITAL
8			ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADMINISTRATION	ADJUSTMENT	ADJUSTMENT
9		REVENUES:						
10		RATE SCHEDULE REVENUES				0		
11		SALES FOR RESALE				0		
12		PROVISION FOR RATE REFUNDS				0		
13		TRANSPORTATION				0		
14		MISCELLANEOUS REVENUES				0		
15		GROSS REVENUES (LINE 10 THRU 14)	$0	$0	$0	$0	$0	$0
16								
17		COST OF SERVICE:						
18		PRODUCTION & GATHERING OPERATION	(18,375)			30,875		
19		PRODUCTION & GATHERING MAINTENANCE	(847)			0		
20		GAS SUPPLY				0		
21		STORAGE OPERATION				0		
22		STORAGE MAINTENANCE				0		
23		TRANSMISSION OPERATION				0		
24		TRANSMISSION MAINTENANCE				0		
25		DISTRIBUTION OPERATION				9,466		
26		DISTRIBUTION MAINTENANCE				0		
27		CUSTOMER ACCOUNTS EXPENSE				39,693		
28		CUSTOMER SERVICE AND INFORMATION EXPENSE				39,857		
29		SALES EXPENSE				0		
30		ADMINISTRATIVE AND GENERAL EXPENSE	18,375			464,038		
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	(847)	-	-	583,929	-	-
32								
33		DEPRECIATION		(156,265)		40,693		
34		DEPLETION		(122,573)		10,344		
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN				0		
36		* AMORTIZATION RE:PROPERTY TAXES				0		
37		* AMORTIZATION RE:USBC				0		
38		* AMORTIZATION RE:COMPENSATED ABSENCES				0		
39		* AMORTIZATION RE:				0		
40		* AMORTIZATION RE:				0		
41		* AMORTIZATION RE:NG MPSC/MCC TAXES			(232)	0		
42		* PENSION DIFFERENTIAL				(54,354)		
43		TAXES OTHER THAN INCOME TAXES				2,542	2,898	
44		INCOME TAXES - FEDERAL - U.S.	0	0	0	0	0	0
45		INCOME TAXES - OTHER	0	0	0	0	0	0
46		DEFERRED INCOME TAXES	334	97,593	81	(289,596)	(1,141)	0
47		SUBTOTAL (LINE 33 THRU 46)	334	(181,245)	(151)	(290,371)	1,757	-
48								
49		TOTAL COST OF SERVICE (LINE 31 + 47)	(513)	(181,245)	(151)	293,558	1,757	-
50								
51		UTILITY OPERATING INCOME (LINE 15 - 49)	513	$181,245	151	(293,558)	(1,757)	-
52								
53		NATURAL GAS UTILITY RATE BASE		61,225	-582			($241,893)
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)						
55								
56		REQUIRED REVENUE INCREASE	($850)	($293,054)	($321)	$486,705	$2,913	($29,397)

	A	B	O	P	Q	R	S	T
1		**NORTHWESTERN ENERGY**						
2		**BATTLE CREEK**						
3		**INCOME STATEMENT**						
4		**ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED**						
5							10.35%	
6				INTEREST	TOTAL	TEST PERIOD	ADJUST TO	
7			INCOME TAX	SYNCHRONIZATION	UPDATES &	@ PRESENT	ROE FROM	DEPRECIATION
8			ADJUSTMENT	ADJUSTMENT	ADJUSTMENTS	RATES	D2012.9.94	ADJUSTMENT
9		REVENUES:						
10		RATE SCHEDULE REVENUES			($107,291)	$2,333,679		
11		SALES FOR RESALE			3,018	62,546		
12		PROVISION FOR RATE REFUNDS			0	0		
13		TRANSPORTATION			0	0		
14		MISCELLANEOUS REVENUES			0	115,677		
15		GROSS REVENUES (LINE 10 THRU 14)	$0	$0	($104,273)	$2,511,901	$0	$0
16								
17		COST OF SERVICE:						
18		PRODUCTION & GATHERING OPERATION			18,875	543,655		
19		PRODUCTION & GATHERING MAINTENANCE			(762)	10,809		
20		GAS SUPPLY			0	0		
21		STORAGE OPERATION			0	0		
22		STORAGE MAINTENANCE			0	0		
23		TRANSMISSION OPERATION			0	0		
24		TRANSMISSION MAINTENANCE			0	0		
25		DISTRIBUTION OPERATION			9,466	9,466		
26		DISTRIBUTION MAINTENANCE			0	0		
27		CUSTOMER ACCOUNTS EXPENSE			39,693	39,693		
28		CUSTOMER SERVICE AND INFORMATION EXPENSE			39,857	39,857		
29		SALES EXPENSE			0	0		
30		ADMINISTRATIVE AND GENERAL EXPENSE			483,284	483,284		
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	-	-	590,413	1,126,765	$0	$0
32								
33		DEPRECIATION			(115,572)	64,182		($123)
34		DEPLETION			(112,229)	498,089		
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN			0	0		
36		* AMORTIZATION RE:PROPERTY TAXES			0	0		
37		* AMORTIZATION RE:USBC			0	0		
38		* AMORTIZATION RE:COMPENSATED ABSENCES			0	0		
39		* AMORTIZATION RE:			0	0		
40		* AMORTIZATION RE:			0	0		
41		* AMORTIZATION RE:NG MPSC/MCC TAXES			(232)	(232)		
42		* PENSION DIFFERENTIAL			(54,354)	(54,354)		
43		TAXES OTHER THAN INCOME TAXES			7,720	67,971		
44		INCOME TAXES - FEDERAL - U.S.	658,360	0	658,360	0	0	0
45		INCOME TAXES - OTHER	136,160	0	136,160	0	0	0
46		DEFERRED INCOME TAXES	(674,263)	(84,346)	(996,193)	186,201	0	43
47		SUBTOTAL (LINE 33 THRU 46)	120,257	(84,346)	(476,341)	761,857	$0	($80)
48								
49		TOTAL COST OF SERVICE (LINE 31 + 47)	120,257	(84,346)	114,072	1,888,622	$0	($80)
50								
51		UTILITY OPERATING INCOME (LINE 15 - 49)	(120,257)	84,346	(218,345)	623,279	$0	$80
52								
53		NATURAL GAS UTILITY RATE BASE	$215,341	$0	34,091	$8,613,221		
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)				7.24%		
55								
56		REQUIRED REVENUE INCREASE	$225,550	($139,841)	$366,151	$13,382	($35,701)	($133)

	A	B	U	V	W	X	Y
1		**NORTHWESTERN ENERGY**					
2		**BATTLE CREEK**					
3		**INCOME STATEMENT**					
4		**ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED**	INTERIM ADJUSTMENTS				
5						INTERIM	INTERIM
6			WORKING		INTEREST	TOTAL	TEST PERIOD
7			CAPITAL	INCOME TAX	SYNCHRONIZATION	UPDATES &	@ PRESENT
8			ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENTS	RATES
9		REVENUES:					
10		RATE SCHEDULE REVENUES				0	$2,333,679
11		SALES FOR RESALE				0	62,546
12		PROVISION FOR RATE REFUNDS				0	0
13		TRANSPORTATION				0	0
14		MISCELLANEOUS REVENUES				0	115,677
15		GROSS REVENUES (LINE 10 THRU 14)	$0	$0	$0	$0	$2,511,901
16							
17		COST OF SERVICE:					
18		PRODUCTION & GATHERING OPERATION				0	543,655
19		PRODUCTION & GATHERING MAINTENANCE				0	10,809
20		GAS SUPPLY				0	0
21		STORAGE OPERATION				0	0
22		STORAGE MAINTENANCE				0	0
23		TRANSMISSION OPERATION				0	0
24		TRANSMISSION MAINTENANCE				0	0
25		DISTRIBUTION OPERATION				0	9,466
26		DISTRIBUTION MAINTENANCE				0	0
27		CUSTOMER ACCOUNTS EXPENSE				0	39,693
28		CUSTOMER SERVICE AND INFORMATION EXPENSE				0	39,857
29		SALES EXPENSE				0	0
30		ADMINISTRATIVE AND GENERAL EXPENSE				0	483,284
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	$0	$0	$0	$0	$1,126,765
32							
33		DEPRECIATION				(123)	64,059
34		DEPLETION				0	498,089
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN				0	0
36		* AMORTIZATION RE:PROPERTY TAXES				0	0
37		* AMORTIZATION RE:USBC				0	0
38		* AMORTIZATION RE:COMPENSATED ABSENCES				0	0
39		* AMORTIZATION RE:				0	0
40		* AMORTIZATION RE:				0	0
41		* AMORTIZATION RE:NG MPSC/MCC TAXES				0	(232)
42		* PENSION DIFFERENTIAL				0	(54,354)
43		TAXES OTHER THAN INCOME TAXES				0	67,971
44		INCOME TAXES - FEDERAL - U.S.	0	0	0	0	0
45		INCOME TAXES - OTHER	0	0	0	0	0
46		DEFERRED INCOME TAXES	0	0	0	43	186,244
47		SUBTOTAL (LINE 33 THRU 46)	$0	$0	$0	($80)	$761,777
48							
49		TOTAL COST OF SERVICE (LINE 31 + 47)	$0	$0	$0	($80)	$1,888,542
50							
51		UTILITY OPERATING INCOME (LINE 15 - 49)	$0	$0	$0	$80	$623,359
52							
53		NATURAL GAS UTILITY RATE BASE		($22)		($22)	$8,613,199
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)					7.24%
55							
56		REQUIRED REVENUE INCREASE	$0	($3)	$0	($35,837)	($22,455)

GENERAL RATE CASE	A	B	C	D	E	F	G	H
ACTUAL TWELVE MONTHS ENDED 2015 NORTHWESTERN ENERGY **NATURAL GAS UTILITY**	NATURAL GAS UTILITY	SUPPLY FUNCTION	NATURAL GAS TRANSMISSION, DISTRIBUTION & STORAGE UTILITY	REVENUE & REVENUE RELATED ADJUSTMENT	SALES & ADMINISTRATIVE & GENERAL ADJUSTMENT	LABOR ADJUSTMENT	ONE-TIME ADJUSTMENT	CORPORATE ALLOCATION ADJUSTMENT
1 Operating Revenues	$176,410,080	($63,618,423)	$112,791,657	$2,482,415	$0	$0	$0	$0
2								
3 Operating Expenses	100,505,442	(48,814,942)	$51,690,500	(3,176,595)	(459,573)	440,406	10,087	(855,820)
4 Book Depreciation	15,396,572	(529,375)	$14,867,197	0	0	0	0	0
5 Amort. of Natural Gas Plant	7,699,240	(6,448,434)	$1,250,806	0	0	0	0	0
6 Amort.-Misc Items	(5,057,706)	308,284	($4,749,421)	0	0	0	0	0
7 Taxes other than Income	29,666,502	(1,388,688)	$28,277,814	233,198	0	30,902	0	0
8								
9 Subtotal Expenses	$148,210,050	($56,873,154)	$91,336,896	($2,943,397)	($459,573)	$471,308	$10,087	($855,820)
10 Net Utility Operating Income Before Inc Tax	$28,200,030	($6,745,269)	$21,454,761	$5,425,811	$459,573	($471,308)	($10,087)	$855,820
11								
12 Amortization of Investment Tax Credit-Net	0	0	$0	0	0	0	0	0
13								
14 Deferred Income Taxes:								
15 Injuries & Damages	38,596	(8,970)	$29,626	0	0	0	0	0
16 Miscellaneous	0	0	$0	0	0	0	0	0
17 Accrued Incentive Compensation	178,759	(22,437)	$156,322	0	0	0	0	0
18 Accelerated Depreciation	4,205,438	(1,270,566)	$2,934,872	0	0	0	0	0
19 Net Operating Loss	3,470,369	(3,445,416)	$24,953	2,137,091	181,014	(185,636)	(3,973)	337,086
20 MPSC/MCC Taxes	(31,365)	4,833	($26,532)	0	0	0	0	0
21 Deferred Revenue	(867,210)	(182,161)	($1,049,371)	0	0	0	0	0
22 Customer Advances for Construction/CIAC	(447,251)	26,058	($421,193)	0	0	0	0	0
23 FAS106 & 112 Post Retirement Benefits	(765,455)	116,764	($648,691)	0	0	0	0	0
24 Costs of Refinancing Debt	(22,682)	4,210	($18,472)	0	0	0	0	0
25 Environmental Reserve	27,768	(3,201)	$24,567	0	0	0	0	0
26 Non-Jurisdictional Items	(2,488,789)	1,548,010	($940,779)	0	0	0	0	0
27 **Subtotal-Deferred Income Tax**	3,298,178	(3,232,876)	65,302	2,137,091	181,014	(185,636)	(3,973)	337,086
28								
29 Income Taxes-Federal	(1,004,923)	1,592,193	$587,270	0	0	0	0	0
30 Income Taxes-Corporation License Tax	(200,597)	334,820	$134,223	0	0	0	0	0
31 Income Taxes-Foreign Taxes	0	0	$0	0	0	0	0	0
32 **Subtotal-Current Income Tax**	(1,205,520)	1,927,012	721,492	0	0	0	0	0
33 Net Utility Operating Income	$26,107,372	($5,439,406)	$20,667,966	$3,288,720	$278,559	($285,672)	($6,114)	$518,734
34 Rate Base			$371,298,214	$0	$0	$0	$0	$0
35 Return on Rate Base			5.57%					
36 NATURAL GAS UTILITY - CALCULATIONS								
37 Operating Revenues	$176,410,080	($63,618,423)	$112,791,657	$2,482,415	$0	$0	$0	$0
38 Operating Expenses	100,505,442	(48,814,942)	51,690,500	(3,176,595)	(459,573)	440,406	10,087	(855,820)
39 Subtotal	$75,904,638	($14,803,481)	$61,101,157	$5,659,009	$459,573	($440,406)	($10,087)	$855,820
40 Depreciation & Amortization	18,038,106	(6,669,525)	11,368,582	-	-	-	-	-
41 Taxes other than Income	29,666,502	(1,388,688)	28,277,814	233,198	-	30,902	-	-
42 Net Utility Operating Income Before Inc Tax	$ 28,200,030	$ (6,745,269)	$ 21,454,761	$ 5,425,811	$ 459,573	$ (471,308)	$ (10,087)	$ 855,820
43 Taxable Additions / (Deductions):								
44 Nondeductible Meal Expense	134,033	(20,904)	$113,129	0	0	0	0	0
45 Bad Debt Expense Accrual Net of Charge-offs	(45,071)	6,189	($38,882)	0	0	0	0	0
46 Penalties	25	(4)	$21	0	0	0	0	0
47 Meters	(1,012,231)	0	($1,012,231)	0	0	0	0	0
48 Customer Advances for Construction/CIAC	1,135,513	(66,157)	$1,069,356	0	0	0	0	0
49 Repairs Expense	(12,695,433)	0	($12,695,433)	0	0	0	0	0

	ACTUAL TWELVE MONTHS ENDED 2015 NORTHWESTERN ENERGY NATURAL GAS UTILITY	I STIPULATION AND MARKET CREDIT ADJUSTMENT	J AMORTIZATION ADJUSTMENT	K TAXES - OTHER THAN INCOME ADJUSTMENT	L DEPRECIATION ADJUSTMENT	M WORKING CAPITAL ADJUSTMENT	N INCOME TAX ADJUSTMENT	O INTEREST SYNCHRONIZATION ADJUSTMENT	P TOTAL UPDATES & ADJUSTMENTS	Q TEST PERIOD @ PRESENT RATES
1	Operating Revenues	$0	$0	$0	$0	$0	$0	$0	2,482,415	115,274,072
2										
3	Operating Expenses	0	0	0	0	0	0	0	(4,041,495)	47,649,005
4	Book Depreciation	0	0	0	250,691	0	0	0	250,691	15,117,887
5	Amort. of Natural Gas Plant	0	0	0	0	0	0	0	0	1,250,806
6	Amort.-Misc Items	0	1,882,981	0	0	0	0	0	1,882,981	(2,866,441)
7	Taxes other than Income	0	0	5,433,565	0	0	0	0	5,697,665	33,975,479
8										
9	Subtotal Expenses	$0	$1,882,981	$5,433,565	$250,691	$0	$0	$0	3,789,841	95,126,737
10	Net Utility Operating Income Before Inc Tax	$0	($1,882,981)	($5,433,565)	($250,691)	$0	$0	$0	(1,307,427)	20,147,334
11										
12	Amortization of Investment Tax Credit-Net	0	0	0	0	0	0	0	0	0
13										
14	Deferred Income Taxes:									
15	Injuries & Damages	0	0	0	0	0	0	0	0	29,626
16	Miscellaneous	0	0	0	0	0	0	0	0	0
17	Accrued Incentive Compensation	0	0	0	0	0	0	0	0	156,322
18	Accelerated Depreciation	0	(659,043)	0	(87,742)	0	3,749,798	0	3,003,013	5,937,885
19	Net Operating Loss	0	0	(2,140,145)	0	0	(4,970,673)	(1,160,749)	(5,805,985)	(5,781,032)
20	MPSC/MCC Taxes	0	0	0	0	0	0	0	0	(26,532)
21	Deferred Revenue	0	0	0	0	0	0	0	0	(1,049,371)
22	Customer Advances for Construction/CIAC	0	0	0	0	0	0	0	0	(421,193)
23	FAS106 & 112 Post Retirement Benefits	0	0	0	0	0	0	0	0	(648,691)
24	Costs of Refinancing Debt	0	0	0	0	0	0	0	0	(18,472)
25	Environmental Reserve	0	0	0	0	0	0	0	0	24,567
26	Non-Jurisdictional Items	0	0	0	0	0	940,779	0	940,779	0
27	**Subtotal-Deferred Income Tax**	0	(659,043)	(2,140,145)	(87,742)	0	(280,096)	(1,160,749)	(1,862,193)	(1,796,891)
28										
29	Income Taxes-Federal	0	0	0	0	0	(587,270)	0	(587,270)	0
30	Income Taxes-Corporation License Tax	0	0	0	0	0	(134,222)	0	(134,222)	1
31	Income Taxes-Foreign Taxes	0	0	0	0	0	0	0	0	0
32	**Subtotal-Current Income Tax**	0	0	0	0	0	(721,491)	0	(721,491)	1
33	Net Utility Operating Income	$0	($1,223,938)	($3,293,420)	($162,949)	$0	$1,001,588	$1,160,749	$1,276,258	$21,944,224
34	Rate Base	($10,456,297)	$163,570	$0	($129,206)	($2,241,586)	$1,401,486	$0	(11,262,033)	360,036,181
35	Return on Rate Base									6.10%
36	NATURAL GAS UTILITY - CALCULATIONS									
37	Operating Revenues	$0	$0	$0	$0	$0	$0	$0	2,482,415	115,274,072
38	Operating Expenses	0	0	0	0	0	0	0	(4,041,495)	47,649,005
39	Subtotal	$0	$0	$0	$0	$0	$0	$0	6,523,910	67,625,067
40	Depreciation & Amortization	-	1,882,981	-	250,691	-	-	-	2,133,672	13,502,253
41	Taxes other than Income	-	-	5,433,565	-	-	-	-	5,697,665	33,975,479
42	Net Utility Operating Income Before Inc Tax	$ -	$ (1,882,981)	$ (5,433,565)	$ (250,691)	$ -	$ -	$ -	(1,307,427)	20,147,334
43	Taxable Additions / (Deductions):									
44	Nondeductible Meal Expense	0	0	0	0	0	0	0	0	113,129
45	Bad Debt Expense Accrual Net of Charge-offs	0	0	0	0	0	0	0	0	(38,882)
46	Penalties	0	0	0	0	0	0	0	0	21
47	Meters	0	0	0	0	0	0	0	0	(1,012,231)
48	Customer Advances for Construction/CIAC	0	0	0	0	0	0	0	0	1,069,356
49	Repairs Expense	0	0	0	0	0	0	0	0	(12,695,433)

GENERAL RATE CASE	R	S	T	U	V	W	X
			INTERIM ADJUSTMENTS				
ACTUAL TWELVE MONTHS ENDED 2015 NORTHWESTERN ENERGY **NATURAL GAS UTILITY**	10.35% ADJUST TO ROE FROM D2012.9.94	DEPRECIATION ADJUSTMENT	WORKING CAPITAL ADJUSTMENT	INCOME TAX ADJUSTMENT	INTEREST YNCHRONIZATIO ADJUSTMENT	INTERIM TOTAL UPDATES & ADJUSTMENTS	INTERIM TEST PERIOD @ PRESENT RATES
1 Operating Revenues	$0	$0	$0	$0	$0	0	115,274,072
2							
3 Operating Expenses	0	0	0	0	0	0	47,649,005
4 Book Depreciation	0	(258,411)	0	0	0	(258,411)	14,859,476
5 Amort. of Natural Gas Plant	0	0	0	0	0	0	1,250,806
6 Amort.-Misc Items	0	0	0	0	0	0	(2,866,441)
7 Taxes other than Income	0	0	0	0	0	0	33,975,479
8							
9 Subtotal Expenses	$0	($258,411)	$0	$0	$0	(258,411)	94,868,326
10 Net Utility Operating Income Before Inc Tax	$0	$258,411	$0	$0	$0	258,411	20,405,745
11							
12 Amortization of Investment Tax Credit-Net	0	0	0	0	0	0	0
13							
14 Deferred Income Taxes:							
15 Injuries & Damages	0	0	0	0	0	0	29,626
16 Miscellaneous	0	0	0	0	0	0	0
17 Accrued Incentive Compensation	0	0	0	0	0	0	156,322
18 Accelerated Depreciation	0	90,444	0	0	0	90,444	6,028,329
19 Net Operating Loss	0	0	0	0	446	446	(5,780,586)
20 MPSC/MCC Taxes	0	0	0	0	0	0	(26,532)
21 Deferred Revenue	0	0	0	0	0	0	(1,049,371)
22 Customer Advances for Construction/CIAC	0	0	0	0	0	0	(421,193)
23 FAS106 & 112 Post Retirement Benefits	0	0	0	0	0	0	(648,691)
24 Costs of Refinancing Debt	0	0	0	0	0	0	(18,472)
25 Environmental Reserve	0	0	0	0	0	0	24,567
26 Non-Jurisdictional Items	0	0	0	0	0	0	0
27 **Subtotal-Deferred Income Tax**	0	90,444	0	0	446	90,890	(1,706,001)
28							
29 Income Taxes-Federal	0	0	0	0	0	0	0
30 Income Taxes-Corporation License Tax	0	0	0	0	0	0	1
31 Income Taxes-Foreign Taxes	0	0	0	0	0	0	0
32 **Subtotal-Current Income Tax**	0	0	0	0	0	0	1
33 Net Utility Operating Income	$0	$167,967	$0	$0	($446)	$167,521	$22,111,745
34 Rate Base	$0	$0	$0	($45,445)	$0	(45,445)	359,990,736
35 Return on Rate Base							6.14%
36 NATURAL GAS UTILITY - CALCULATIONS							
37 Operating Revenues	$0	$0	$0	$0	$0	0	115,274,072
38 Operating Expenses	0	0	0	0	0	0	47,649,005
39 Subtotal	$0	$0	$0	$0	$0	0	67,625,067
40 Depreciation & Amortization	-	(258,411)	-	-	-	(258,411)	13,243,842
41 Taxes other than Income	-	-	-	-	-	0	33,975,479
42 Net Utility Operating Income Before Inc Tax	$ -	$ 258,411	$ -	$ -	$ -	258,411	20,405,745
43 Taxable Additions / (Deductions):							
44 Nondeductible Meal Expense	0	0	0	0	0	0	113,129
45 Bad Debt Expense Accrual Net of Charge-offs	0	0	0	0	0	0	(38,882)
46 Penalties	0	0	0	0	0	0	21
47 Meters	0	0	0	0	0	0	(1,012,231)
48 Customer Advances for Construction/CIAC	0	0	0	0	0	0	1,069,356
49 Repairs Expense	0	0	0	0	0	0	(12,695,433)

GENERAL RATE CASE	A	B	C	D	E	F	G	H
ACTUAL TWELVE MONTHS ENDED 2015 NORTHWESTERN ENERGY NATURAL GAS UTILITY	NATURAL GAS UTILITY	SUPPLY FUNCTION	NATURAL GAS TRANSMISSION, DISTRIBUTION & STORAGE UTILITY	REVENUE & REVENUE RELATED ADJUSTMENT	SALES & ADMINISTRATIVE & GENERAL ADJUSTMENT	LABOR ADJUSTMENT	ONE-TIME ADJUSTMENT	CORPORATE ALLOCATION ADJUSTMENT
50 Accrued Incentive Compensation	(453,850)	56,967	($396,883)	0	0	0	0	0
51 MPSC/MCC Taxes	79,632	(12,271)	$67,361	0	0	0	0	0
52 Costs of Refinancing Debt	57,587	(10,688)	$46,899	0	0	0	0	0
53 Accelerated Depreciation-Excess BLM Tx vs Bk Dep	3,118,949	(942,311)	$2,176,638	0	0	0	0	0
54 Accelerated Depreciation-Excess Tx Rtn vs BLM Tx	(12,015,534)	3,630,186	($8,385,348)	0	0	0	0	0
55 Removal Costs Net of Salvage	(2,256,491)	0	($2,256,491)	0	0	0	0	0
56 Deferred Revenue	2,201,740	462,485	$2,664,225	0	0	0	0	0
57 FAS106 & 112 Post Retirement Benefits	1,943,395	(296,449)	$1,646,946	0	0	0	0	0
58 Environmental Reserve	(70,498)	8,127	($62,371)	0	0	0	0	0
59 Injuries & Damages	(97,991)	22,773	($75,218)	0	0	0	0	0
60 Net Operating Loss	(8,810,839)	8,747,487	($63,352)	(5,425,811)	(459,573)	471,308	10,087	(855,820)
61 Excludable Foreign Income	(141,440)	0	($141,440)	0	0	0	0	0
62 MT Corporation License Tax	623,073	(494,404)	$128,669	0	0	0	0	0
63 Deduct Interest Charges	(8,502,237)	2,484,334	($6,017,903)	0	0	0	0	0
64 Total Tax Additons / (Deductions)	($36,807,671)	$13,575,362	($23,232,308)	($5,425,811)	($459,573)	$471,308	$10,087	($855,820)
65 Federal Taxable Income	$ (8,607,641)	$ 6,830,094	$ (1,777,547)	$ -	$ -	$ -	$ -	$ -
66 Federal Income Tax @ 35%	($3,012,674)	$2,390,533	($622,141)	$0	$0	$0	$0	$0
67 Foreign Income Tax	0	0	$0	0	0	0	0	0
68 Foreign Income Tax Credit	0	0	$0	0	0	0	0	0
69 Non-Jurisdictional Items	2,488,789	(1,548,010)	$940,779	0	0	0	0	0
70 Prior Period Adjustments	(481,038)	749,670	$268,632	0	0	0	0	0
71 Audit Adjustments	0	0	$0	0	0	0	0	0
72 Total Federal Income Tax	(1,004,923)	1,592,193	587,270	0	0	0	0	0
73								
74								
75 Montana Corporate License Tax								
76 Federal Taxable Income B4 MT Corp Tx Deductn & N	$ (9,230,714)	$ 7,324,498	($1,906,216)	$ -	$ -	$ -	$ -	$ -
77 Add:								
78 Other	0	0	$0	0	0	0	0	0
79 Other State Taxes Paid	0	0	$0	0	0	0	0	0
80								
81 Reduction for Unitary Allocation	0	0	$0	0	0	0	0	0
82								
83 Montana Taxable Income	($9,230,714)	$7,324,498	($1,906,216)	$0	$0	$0	$0	$0
84 Mont. Corp. Lic. Tax @ 6.75%	($623,073)	$494,404	($128,669)	0	0	0	0	0
85 Net Tax Adjustment	$422,476	($159,584)	$262,892	$0	$0	$0	$0	$0
86 Mont. Corp. License Tax	($200,597)	$334,820	$134,223	$0	$0	$0	$0	$0
87 Actual 6.75%	(623,073)	494,404	(128,671)	0	0	0	0	0
88								
89 Change in tax rates	0	0	$0	0	0	0	0	0
90 Non-Jurisdictional Items	422,476	(159,584)	$262,892	0	0	0	0	0
91 Net Tax Adjustment	422,476	(159,584)	262,892	0	0	0	0	0
COMPUTATION OF REQUIRED RETURN AND REVENUE INCREASE								
1 Electric Utility Rate Base			$371,298,214	$0	$0	$0	$0	$0
2 Rate of Return			7.33%	7.33%	7.33%	7.33%	7.33%	7.33%

	ACTUAL TWELVE MONTHS ENDED 2015 NORTHWESTERN ENERGY NATURAL GAS UTILITY	I STIPULATION AND MARKET CREDITS ADJUSTMENT	J AMORTIZATION ADJUSTMENT	K TAXES - OTHER THAN INCOME ADJUSTMENT	L DEPRECIATION ADJUSTMENT	M WORKING CAPITAL ADJUSTMENT	N INCOME TAX ADJUSTMENT	O INTEREST SYNCHRONIZATION ADJUSTMENT	P TOTAL UPDATES & ADJUSTMENTS	Q TEST PERIOD @ PRESENT RATES
50	Accrued Incentive Compensation	0	0	0	0	0	0	0	0	(396,883)
51	MPSC/MCC Taxes	0	0	0	0	0	0	0	0	67,361
52	Costs of Refinancing Debt	0	0	0	0	0	0	0	0	46,899
53	Accelerated Depreciation-Excess BLM Tx vs Bk Dep	0	0	0	0	0	0	0	0	2,176,638
54	Accelerated Depreciation-Excess Tx Rtn vs BLM Tx	0	1,882,981	0	250,691	0	(10,713,709)	0	(8,580,037)	(16,965,385)
55	Removal Costs Net of Salvage	0	0	0	0	0	0	0	0	(2,256,491)
56	Deferred Revenue	0	0	0	0	0	0	0	0	2,664,225
57	FAS106 & 112 Post Retirement Benefits	0	0	0	0	0	0	0	0	1,646,946
58	Environmental Reserve	0	0	0	0	0	0	0	0	(62,371)
59	Injuries & Damages	0	0	0	0	0	0	0	0	(75,218)
60	Net Operating Loss	0	0	5,433,565	0	0	12,619,925	2,946,998	14,740,678	14,677,326
61	Excludable Foreign Income	0	0	0	0	0	0	0	0	(141,440)
62	MT Corporation License Tax	0	0	0	0	0	(128,670)	0	(128,670)	(1)
63	Deduct Interest Charges	0	0	0	0	0	0	(2,946,998)	(2,946,998)	(8,964,901)
64	Total Tax Additons / (Deductions)	$0	$1,882,981	$5,433,565	$250,691	$0	$1,777,546	$0	$3,084,973	($20,147,335)
65	Federal Taxable Income	$ -	$ -	$ -	$ -	$ -	$ 1,777,546	$ -	$ 1,777,546	$ (1)
66	Federal Income Tax @ 35%	$0	$0	$0	$0	$0	$622,141	$0	622,141	$0
67	Foreign Income Tax	0	0	0	0	0	0	0	0	0
68	Foreign Income Tax Credit	0	0	0	0	0	0	0	0	0
69	Non-Jurisdictional Items	0	0	0	0	0	(940,779)	0	(940,779)	0
70	Prior Period Adjustments	0	0	0	0	0	(268,632)	0	(268,632)	0
71	Audit Adjustments	0	0	0	0	0	0	0	0	0
72	Total Federal Income Tax	0	0	0	0	0	(587,270)	0	(587,270)	0
73										
74										
75	Montana Corporate License Tax									
76	Federal Taxable Income B4 MT Corp Tx Deductn & N	$ -	$ -	$ -	$ -	$ -	$ 1,906,216	$ -	1,906,216	(0)
77	Add:									
78	Other	0	0	0	0	0	0	0	0	0
79	Other State Taxes Paid	0	0	0	0	0	0	0	0	0
80										
81	Reduction for Unitary Allocation	0	0	0	0	0	0	0	0	0
82										
83	Montana Taxable Income	$0	$0	$0	$0	$0	$1,906,216	$0	1,906,216	(0)
84	Mont. Corp. Lic. Tax @ 6.75%	0	0	0	0	0	128,670	0	128,670	1
85	Net Tax Adjustment	$0	$0	$0	$0	$0	($262,892)	$0	(262,892)	0
86	Mont. Corp. License Tax	$0	$0	$0	$0	$0	($134,222)	$0	(134,222)	1
87	Actual 6.75%	0	0	0	0	0	128,670	0	128,670	(1)
88										
89	Change in tax rates	0	0	0	0	0	0	0	0	0
90	Non-Jurisdictional Items	0	0	0	0	0	(262,892)	0	(262,892)	0
91	Net Tax Adjustment	0	0	0	0	0	(262,892)	0	(262,892)	0

	COMPUTATION OF REQUIRED RETURN AND REVENUE INCREASE									
1	Electric Utility Rate Base	($10,456,297)	$163,570	$0	($129,206)	($2,241,586)	$1,401,486	$0	($11,262,033)	$360,036,181
2	Rate of Return	7.33%	7.33%	7.33%	7.33%	7.33%	7.33%	7.33%	7.33%	7.33%

GENERAL RATE CASE

ACTUAL TWELVE MONTHS ENDED 2015
NORTHWESTERN ENERGY
NATURAL GAS UTILITY

		R	S	T	U	V	W	X
		INTERIM ADJUSTMENTS						
		10.35% ADJUST TO ROE FROM D2012.9.94	DEPRECIATION ADJUSTMENT	WORKING CAPITAL ADJUSTMENT	INCOME TAX ADJUSTMENT	INTEREST YNCHRONIZATIO ADJUSTMENT	INTERIM TOTAL UPDATES & ADJUSTMENTS	INTERIM TEST PERIOD @ PRESENT RATES
50	Accrued Incentive Compensation	0	0	0	0	0	0	(396,883)
51	MPSC/MCC Taxes	0	0	0	0	0	0	67,361
52	Costs of Refinancing Debt	0	0	0	0	0	0	46,899
53	Accelerated Depreciation-Excess BLM Tx vs Bk Dep	0	0	0	0	0	0	2,176,638
54	Accelerated Depreciation-Excess Tx Rtn vs BLM Tx	0	(258,411)	0	0	0	(258,411)	(17,223,796)
55	Removal Costs Net of Salvage	0	0	0	0	0	0	(2,256,491)
56	Deferred Revenue	0	0	0	0	0	0	2,664,225
57	FAS106 & 112 Post Retirement Benefits	0	0	0	0	0	0	1,646,946
58	Environmental Reserve	0	0	0	0	0	0	(62,371)
59	Injuries & Damages	0	0	0	0	0	0	(75,218)
60	Net Operating Loss	0	0	0	(0)	(1,132)	(1,132)	14,676,195
61	Excludable Foreign Income	0	0	0	0	0	0	(141,440)
62	MT Corporation License Tax	0	0	0	0	0	0	(1)
63	Deduct Interest Charges	0	0	0	0	1,132	1,132	(8,963,769)
64	Total Tax Additons / (Deductions)	$0	($258,411)	$0	($0)	$0	($258,411)	($20,405,746)
65	Federal Taxable Income	$ -	$ -	$ -	$ (0)	$ -	$ -	$ (1)
66	Federal Income Tax @ 35%	$0	$0	$0	$0	$0	0	$0
67	Foreign Income Tax	0	0	0	0	0	0	0
68	Foreign Income Tax Credit	0	0	0	0	0	0	0
69	Non-Jurisdictional Items	0	0	0	0	0	0	0
70	Prior Period Adjustments	0	0	0	0	0	0	0
71	Audit Adjustments	0	0	0	0	0	0	0
72	Total Federal Income Tax	0	0	0	0	0	0	0
73								
74								
75	Montana Corporate License Tax							
76	Federal Taxable Income B4 MT Corp Tx Deductn & N	$ -	$ -	$ -	$ (0)	$ -	(0)	(0)
77	Add:							
78	Other	0	0	0	0	0	0	0
79	Other State Taxes Paid	0	0	0	0	0	0	0
80								
81	Reduction for Unitary Allocation	0	0	0	0	0	0	0
82								
83	Montana Taxable Income	$0	$0	$0	($0)	$0	(0)	(0)
84	Mont. Corp. Lic. Tax @ 6.75%	0	0	0	0	0	0	1
85	Net Tax Adjustment	$0	$0	$0	$0	$0	0	0
86	Mont. Corp. License Tax	$0	$0	$0	$0	$0	0	1
87	Actual 6.75%	0	0	0	0	0	0	(1)
88								
89	Change in tax rates	0	0	0	0	0	0	0
90	Non-Jurisdictional Items	0	0	0	0	0	0	0
91	Net Tax Adjustment	0	0	0	0	0	0	0

COMPUTATION OF REQUIRED RETURN AND REVENUE INCREASE

1	Electric Utility Rate Base	$360,036,181	$0	$0	($45,445)	$0	($45,445)	$359,990,736
2	Rate of Return	-0.25%	7.08%	7.08%	7.08%	7.08%	7.08%	7.08%

GENERAL RATE CASE	A	B	C	D	E	F	G	H
ACTUAL TWELVE MONTHS ENDED 2015 NORTHWESTERN ENERGY **NATURAL GAS UTILITY**	NATURAL GAS UTILITY	SUPPLY FUNCTION	NATURAL GAS TRANSMISSION, DISTRIBUTION & STORAGE UTILITY	REVENUE & REVENUE RELATED ADJUSTMENT	SALES & ADMINISTRATIVE & GENERAL ADJUSTMENT	LABOR ADJUSTMENT	ONE-TIME ADJUSTMENT	CORPORATE ALLOCATION ADJUSTMENT
3								
4								
5 Net Operating Income			27,216,159	0	0	0	0	0
6								
7 Net Operating Income for the Year								
8 Ended 12/31/15 Adjusted for Known Changes			20,667,966	3,288,720	278,559	(285,672)	(6,114)	518,734
9								
10 **Required Incremental Increase in Net**								
11 **Operating Income**			**$6,548,193**	**($3,288,720)**	**($278,559)**	**$285,672**	**$6,114**	**($518,734)**
12								
13 Add:								
14 MPSC Tax			42,341	(21,265)	(1,801)	1,847	40	(3,354)
15 Consumer Counsel Tax			10,857	(5,453)	(462)	474	10	(860)
16 Incremental Income Taxes			4,255,178	(2,137,091)	(181,014)	185,636	3,973	(337,086)
17								
18 **Required Revenue Increase**			**$10,856,569**	**($5,452,529)**	**($461,836)**	**$473,629**	**$10,137**	**($860,034)**
19								
20								
21 MPSC Tax (0.39%)			42,341	(21,265)	(1,801)	1,847	40	(3,354)
22								
23 Consumer Counsel Tax (0.10%)			10,857	(5,453)	(462)	474	10	(860)
24								
25 Taxable Income for State Income Tax			$10,803,371	($5,425,811)	($459,573)	$471,308	$10,087	($855,820)
26								
27 State Income Tax (6.75%) (Unitary Factor = 1.00)			729,228	(366,242)	(31,021)	31,813	681	(57,768)
28								
29 Taxable Income for Federal Income Tax			$10,074,143	($5,059,569)	($428,552)	$439,495	$9,406	($798,052)
30								
31 Reduction of Fed.Inc.Tax-Due to MCLT Expense			(255,230)	128,185	10,857	(11,135)	(238)	20,219
32 Federal Income Tax Expense (35%)			3,781,180	(1,899,034)	(160,850)	164,958	3,530	(299,537)
33								
34 **Required Incremental Increase in Net**								
35 **Operating Income**			**$6,548,193**	**($3,288,720)**	**($278,559)**	**$285,672**	**$6,114**	**($518,734)**

GENERAL RATE CASE

	ACTUAL TWELVE MONTHS ENDED 2015 NORTHWESTERN ENERGY NATURAL GAS UTILITY	I STIPULATION AND MARKET CREDIT ADJUSTMENT	J AMORTIZATION ADJUSTMENT	K TAXES - OTHER THAN INCOME ADJUSTMENT	L DEPRECIATION ADJUSTMENT	M WORKING CAPITAL ADJUSTMENT	N INCOME TAX ADJUSTMENT	O INTEREST SYNCHRONIZATION ADJUSTMENT	P TOTAL UPDATES & ADJUSTMENTS	Q TEST PERIOD @ PRESENT RATES
3										
4										
5	Net Operating Income	(766,447)	11,990	0	(9,471)	(164,308)	102,729	0	(825,507)	26,390,652
6										
7	Net Operating Income for the Year									
8	Ended 12/31/15 Adjusted for Known Changes	0	(1,223,938)	(3,293,420)	(162,949)	0	1,001,588	1,160,749	1,276,258	21,944,224
9										
10	**Required Incremental Increase in Net**									
11	**Operating Income**	**($766,447)**	**$1,235,928**	**$3,293,420**	**$153,478**	**($164,308)**	**($898,859)**	**($1,160,749)**	**($2,101,764)**	**$4,446,429**
12										
13	Add:									
14	MPSC Tax	(4,956)	7,992	21,295	992	(1,062)	(5,812)	(7,505)	(13,589)	28,752
15	Consumer Counsel Tax	(1,271)	2,049	5,460	254	(272)	(1,490)	(1,924)	(3,485)	7,372
16	Incremental Income Taxes	(498,056)	803,137	2,140,146	99,734	(106,772)	(584,101)	(754,284)	(1,365,778)	2,889,400
17										
18	**Required Revenue Increase**	**($1,270,730)**	**$2,049,106**	**$5,460,321**	**$254,458**	**($272,414)**	**($1,490,262)**	**($1,924,462)**	**($3,484,616)**	**$7,371,953**
19										
20										
21	MPSC Tax (0.39%)	(4,956)	7,992	21,295	992	(1,062)	(5,812)	(7,505)	(13,589)	28,752
22										
23	Consumer Counsel Tax (0.10%)	(1,271)	2,049	5,460	254	(272)	(1,490)	(1,924)	(3,485)	7,372
24										
25	Taxable Income for State Income Tax	($1,264,503)	$2,039,065	$5,433,566	$253,212	($271,080)	($1,482,960)	($1,915,033)	(3,467,542)	7,335,829
26										
27	State Income Tax (6.75%) (Unitary Factor = 1.00)	(85,354)	137,637	366,766	17,092	(18,298)	(100,100)	(129,265)	(234,059)	495,169
28										
29	Taxable Income for Federal Income Tax	($1,179,149)	$1,901,428	$5,066,800	$236,120	($252,782)	($1,382,860)	($1,785,768)	($3,233,483)	$6,840,660
30										
31	Reduction of Fed.Inc.Tax-Due to MCLT Expense	29,874	(48,173)	(128,368)	(5,982)	6,404	35,035	45,243	81,921	(173,309)
32	Federal Income Tax Expense (35%)	(442,576)	713,673	1,901,748	88,624	(94,878)	(519,036)	(670,262)	(1,213,640)	2,567,540
33										
34	**Required Incremental Increase in Net**									
35	**Operating Income**	**($766,447)**	**$1,235,928**	**$3,293,420**	**$153,478**	**($164,308)**	**($898,859)**	**($1,160,749)**	**($2,101,764)**	**$4,446,429**

	GENERAL RATE CASE	R	S	T	U	V	W	X
		INTERIM ADJUSTMENTS						
	ACTUAL TWELVE MONTHS ENDED 2015 NORTHWESTERN ENERGY **NATURAL GAS UTILITY**	10.35% ADJUST TO ROE FROM D2012.9.94	DEPRECIATION ADJUSTMENT	WORKING CAPITAL ADJUSTMENT	INCOME TAX ADJUSTMENT	INTEREST YNCHRONIZATIO ADJUSTMENT	INTERIM TOTAL UPDATES & ADJUSTMENTS	INTERIM TEST PERIOD @ PRESENT RATES
3								
4								
5	Net Operating Income	(900,090)	0	0	(3,218)	0	(3,218)	25,487,344
6								
7	Net Operating Income for the Year							
8	Ended 12/31/15 Adjusted for Known Changes	0	167,967	0	0	(446)	167,521	22,111,745
9								
10	**Required Incremental Increase in Net**							
11	**Operating Income**	**($900,090)**	**($167,967)**	**$0**	**($3,218)**	**$446**	**($1,070,829)**	**$3,375,600**
12								
13	Add:							
14	MPSC Tax	(5,820)	(1,086)	0	(21)	3	(6,924)	21,828
15	Consumer Counsel Tax	(1,492)	(278)	0	(5)	1	(1,774)	5,598
16	Incremental Income Taxes	(584,901)	(109,149)	0	(2,091)	290	(695,851)	2,193,549
17								
18	**Required Revenue Increase**	**($1,492,303)**	**($278,480)**	**$0**	**($5,335)**	**$740**	**($1,775,378)**	**$5,596,575**
19								
20								
21	MPSC Tax (0.39%)	(5,820)	(1,086)	0	(21)	3	(6,924)	21,828
22								
23	Consumer Counsel Tax (0.10%)	(1,492)	(278)	0	(5)	1	(1,774)	5,598
24								
25	Taxable Income for State Income Tax	($1,484,991)	($277,116)	$0	($5,309)	$736	(1,766,680)	5,569,149
26								
27	State Income Tax (6.75%) (Unitary Factor = 1.00)	(100,237)	(18,705)	0	(358)	50	(119,250)	375,919
28								
29	Taxable Income for Federal Income Tax	($1,384,754)	($258,411)	$0	($4,951)	$686	($1,647,430)	$5,193,230
30								
31	Reduction of Fed.Inc.Tax-Due to MCLT Expense	35,083	6,547	0	125	(18)	41,737	(131,572)
32	Federal Income Tax Expense (35%)	(519,747)	(96,991)	0	(1,858)	258	(618,338)	1,949,202
33								
34	**Required Incremental Increase in Net**							
35	**Operating Income**	**($900,090)**	**($167,967)**	**$0**	**($3,218)**	**$446**	**($1,070,829)**	**$3,375,600**

GENERAL RATE CASE	A	B	C	D	E	F	G	H
ACTUAL TWELVE MONTHS ENDED 2015 NORTHWESTERN ENERGY **NATURAL GAS UTILITY**	BATTLE CREEK UTILITY	BATTLE CREEK VARIABLE	BATTLE CREEK FIXED	REVENUE & REVENUE RELATED ADJUSTMENT	SALES & ADMINISTRATIVE & GENERAL ADJUSTMENT	LABOR ADJUSTMENT	ONE-TIME ADJUSTMENT	DEPRECIATION AND DEPLETION ADJUSTMENT
1 Operating Revenues	$2,616,174	$0	$2,616,174	($104,273)	$0	$0	$0	$0
2								
3 Operating Expenses	479,820	(56,533)	$536,352	0	871	6,459	(847)	0
4 Book Depreciation	179,754	0	$179,754	0	0	0	0	(156,265)
5 Amort. of Natural Gas Plant	610,318	0	$610,318	0	0	0	0	(122,573)
6 Amort.-Misc Items	0	0	$0	0	0	0	0	0
7 Taxes other than Income	121,717	61,465	$60,251	1,828	0	452	0	0
8								
9 Subtotal Expenses	$1,391,609	$4,933	$1,386,676	$1,828	$871	$6,911	($847)	($278,838)
10 Net Utility Operating Income Before Inc Tax	$1,224,565	($4,933)	$1,229,498	($106,101)	($871)	($6,911)	$847	$278,838
11								
12 Amortization of Investment Tax Credit-Net	0	0	$0	0	0	0	0	0
13								
14 Deferred Income Taxes:								
15 Injuries & Damages	0	0	$0	0	0	0	0	0
16 Miscellaneous	0	0	$0	0	0	0	0	0
17 Accrued Incentive Compensation	0	0	$0	0	0	0	0	0
18 Accelerated Depreciation	143,862	0	$143,862	0	0	0	0	97,593
19 Net Operating Loss	471,078	(1,943)	$473,021	(41,790)	(343)	(2,722)	334	0
20 MPSC/MCC Taxes	0	0	$0	0	0	0	0	0
21 Deferred Revenue	0	0	$0	0	0	0	0	0
22 Customer Advances for Construction/CIAC	0	0	$0	0	0	0	0	0
23 FAS106 & 112 Post Retirement Benefits	0	0	$0	0	0	0	0	0
24 Costs of Refinancing Debt	0	0	$0	0	0	0	0	0
25 Environmental Reserve	0	0	$0	0	0	0	0	0
26 Non-Jurisdictional Items	565,511	0	$565,511	0	0	0	0	0
27 **Subtotal-Deferred Income Tax**	1,180,451	(1,943)	1,182,394	(41,790)	(343)	(2,722)	334	97,593
28								
29 Income Taxes-Federal	(658,360)	0	($658,360)	0	0	0	0	0
30 Income Taxes-Corporation License Tax	(136,160)	0	($136,160)	0	0	0	0	0
31 Income Taxes-Foreign Taxes	0	0	$0	0	0	0	0	0
32 **Subtotal-Current Income Tax**	(794,520)	0	(794,520)	0	0	0	0	0
33 Net Utility Operating Income	$838,634	($2,990)	$841,624	($64,311)	($528)	($4,189)	$513	$181,245
34 Rate Base			$8,579,130	$0	$0	$0	$0	$61,225
35 Return on Rate Base			9.81%					
36 NATURAL GAS UTILITY - CALCULATIONS								
37 Operating Revenues	$2,616,174	$0	$2,616,174	($104,273)	$0	$0	$0	$0
38 Operating Expenses	479,820	(56,533)	536,352	0	871	6,459	(847)	0
39 Subtotal	$2,136,354	$56,533	$2,079,821	($104,273)	($871)	($6,459)	$847	$0
40 Depreciation & Amortization	790,072	-	790,072	-	-	-	-	(278,838)
41 Taxes other than Income	121,717	61,465	60,251	1,828	-	452	-	-
42 Net Utility Operating Income Before Inc Tax	$ 1,224,565	$ (4,933)	$ 1,229,498	$ (106,101)	$ (871)	$ (6,911)	$ 847	$ 278,838
43 Taxable Additions / (Deductions):								
44 Nondeductible Meal Expense	0	0	$0	0	0	0	0	0
45 Bad Debt Expense Accrual Net of Charge-offs	0	0	$0	0	0	0	0	0
46 Penalties	0	0	$0	0	0	0	0	0
47 Meters	0	0	$0	0	0	0	0	0

GENERAL RATE CASE

	ACTUAL TWELVE MONTHS ENDED 2015 NORTHWESTERN ENERGY **NATURAL GAS UTILITY**	I AMORTIZATION ADJUSTMENT	J ALLOCATION OF GAS PRODUCTION ADMINISTRATION	K TAXES - OTHER THAN INCOME ADJUSTMENT	L WORKING CAPITAL ADJUSTMENT	M INCOME TAX ADJUSTMENT	N INTEREST SYNCHRONIZATION ADJUSTMENT	O TOTAL UPDATES & ADJUSTMENTS	P TEST PERIOD @ PRESENT RATES	10.35% ADJUST TO ROE FROM D2012.9.94
1	Operating Revenues	$0	$0	$0	$0	$0	$0	(104,273)	2,511,901	$0
2										
3	Operating Expenses	0	583,929	0	0	0	0	590,413	1,126,765	0
4	Book Depreciation	0	40,693	0	0	0	0	(115,572)	64,182	0
5	Amort. of Natural Gas Plant	0	10,344	0	0	0	0	(112,229)	498,089	0
6	Amort.-Misc Items	(232)	(54,354)	0	0	0	0	(54,586)	(54,586)	0
7	Taxes other than Income	0	2,542	2,898	0	0	0	7,720	67,971	0
8										
9	Subtotal Expenses	($232)	$583,154	$2,898	$0	$0	$0	315,745	1,702,421	$0
10	Net Utility Operating Income Before Inc Tax	$232	($583,154)	($2,898)	$0	$0	$0	(420,018)	$809,480	$0
11										
12	Amortization of Investment Tax Credit-Net	0	0	0	0	0	0	0	0	0
13										
14	Deferred Income Taxes:									
15	Injuries & Damages	0	3,516	0	0	0	0	3,516	3,516	0
16	Miscellaneous	0	0	0	0	0	0	0	0	0
17	Accrued Incentive Compensation	0	(2,140)	0	0	0	0	(2,140)	(2,140)	0
18	Accelerated Depreciation	81	511,106	0	0	0	0	608,780	752,642	0
19	Net Operating Loss	0	(748,048)	(1,141)	0	(108,752)	(84,346)	(986,808)	(513,787)	0
20	MPSC/MCC Taxes	0	(489)	0	0	0	0	(489)	(489)	0
21	Deferred Revenue	0	(38,689)	0	0	0	0	(38,689)	(38,689)	0
22	Customer Advances for Construction/CIAC	0	(3,466)	0	0	0	0	(3,466)	(3,466)	0
23	FAS106 & 112 Post Retirement Benefits	0	(9,484)	0	0	0	0	(9,484)	(9,484)	0
24	Costs of Refinancing Debt	0	(1,042)	0	0	0	0	(1,042)	(1,042)	0
25	Environmental Reserve	0	(860)	0	0	0	0	(860)	(860)	0
26	Non-Jurisdictional Items	0	0	0	0	(565,511)	0	(565,511)	0	0
27	**Subtotal-Deferred Income Tax**	81	(289,596)	(1,141)	0	(674,263)	(84,346)	(996,193)	186,201	0
28										
29	Income Taxes-Federal	0	0	0	0	658,360	0	658,360	0	0
30	Income Taxes-Corporation License Tax	0	0	0	0	136,160	0	136,160	0	0
31	Income Taxes-Foreign Taxes	0	0	0	0	0	0	0	0	0
32	**Subtotal-Current Income Tax**	0	0	0	0	794,520	0	794,520	0	0
33	Net Utility Operating Income	$151	($293,558)	($1,757)	$0	($120,257)	$84,346	($218,345)	$623,279	$0
34	Rate Base	($582)	$0	$0	($241,893)	$215,341	$0	34,091	8,613,221	$0
35	Return on Rate Base								7.24%	
36	NATURAL GAS UTILITY - CALCULATIONS									
37	Operating Revenues	$0	$0	$0	$0	$0	$0	(104,273)	2,511,901	$0
38	Operating Expenses	0	583,929	0	0	0	0	590,413	1,126,765	0
39	Subtotal	$0	($583,929)	$0	$0	$0	$0	(694,685)	$1,385,136	$0
40	Depreciation & Amortization	(232)	(3,317)	-	-	-	-	(282,388)	507,685	-
41	Taxes other than Income	-	2,542	2,898	-	-	-	7,720	67,971	-
42	Net Utility Operating Income Before Inc Tax	$ 232	$ (583,154)	$ (2,898)	$ -	$ -	$ -	(420,018)	809,480	$ -
43	Taxable Additions / (Deductions):									
44	Nondeductible Meal Expense	0	2,872	0	0	0	0	2,872	2,872	0
45	Bad Debt Expense Accrual Net of Charge-offs	0	26	0	0	0	0	26	26	0
46	Penalties	0	1	0	0	0	0	1	1	0
47	Meters	0	0	0	0	0	0	0	0	0

GENERAL RATE CASE

		Q	R	S	T	U	V
		INTERIM ADJUSTMENTS					
	ACTUAL TWELVE MONTHS ENDED 2015 NORTHWESTERN ENERGY **NATURAL GAS UTILITY**	DEPRECIATION ADJUSTMENT	WORKING CAPITAL ADJUSTMENT	INCOME TAX ADJUSTMENT	INTEREST YNCHRONIZATIO ADJUSTMENT	INTERIM TOTAL UPDATES & ADJUSTMENTS	INTERIM TEST PERIOD @ PRESENT RATES
1	Operating Revenues	$0	$0	$0	$0	0	2,511,901
2							
3	Operating Expenses	0	0	0	0	0	1,126,765
4	Book Depreciation	(123)	0	0	0	(123)	64,059
5	Amort. of Natural Gas Plant	0	0	0	0	0	498,089
6	Amort.-Misc Items	0	0	0	0	0	(54,586)
7	Taxes other than Income	0	0	0	0	0	67,971
8							
9	Subtotal Expenses	($123)	$0	$0	$0	(123)	1,702,298
10	Net Utility Operating Income Before Inc Tax	$123	$0	$0	$0	123	809,603
11							
12	Amortization of Investment Tax Credit-Net	0	0	0	0	0	0
13							
14	Deferred Income Taxes:						
15	Injuries & Damages	0	0	0	0	0	3,516
16	Miscellaneous	0	0	0	0	0	0
17	Accrued Incentive Compensation	0	0	0	0	0	(2,140)
18	Accelerated Depreciation	43	0	0	0	43	752,685
19	Net Operating Loss	0	0	0	0	0	(513,787)
20	MPSC/MCC Taxes	0	0	0	0	0	(489)
21	Deferred Revenue	0	0	0	0	0	(38,689)
22	Customer Advances for Construction/CIAC	0	0	0	0	0	(3,466)
23	FAS106 & 112 Post Retirement Benefits	0	0	0	0	0	(9,484)
24	Costs of Refinancing Debt	0	0	0	0	0	(1,042)
25	Environmental Reserve	0	0	0	0	0	(860)
26	Non-Jurisdictional Items	0	0	0	0	0	0
27	**Subtotal-Deferred Income Tax**	43	0	0	0	43	186,244
28							
29	Income Taxes-Federal	0	0	0	0	0	0
30	Income Taxes-Corporation License Tax	0	0	0	0	0	0
31	Income Taxes-Foreign Taxes	0	0	0	0	0	0
32	**Subtotal-Current Income Tax**	0	0	0	0	0	0
33	Net Utility Operating Income	$80	$0	$0	$0	$80	$623,359
34	Rate Base	$0	$0	($22)	$0	(22)	8,613,199
35	Return on Rate Base						7.24%
36	NATURAL GAS UTILITY - CALCULATIONS						
37	Operating Revenues	$0	$0	$0	$0	0	2,511,901
38	Operating Expenses	0	0	0	0	0	1,126,765
39	Subtotal	$0	$0	$0	$0	0	1,385,136
40	Depreciation & Amortization	(123)	-	-	-	(123)	507,562
41	Taxes other than Income	-	-	-	-	0	67,971
42	Net Utility Operating Income Before Inc Tax	$ 123	$ -	$ -	$ -	123	809,603
43	Taxable Additions / (Deductions):						
44	Nondeductible Meal Expense	0	0	0	0	0	2,872
45	Bad Debt Expense Accrual Net of Charge-offs	0	0	0	0	0	26
46	Penalties	0	0	0	0	0	1
47	Meters	0	0	0	0	0	0

GENERAL RATE CASE	A	B	C	D	E	F	G	H
ACTUAL TWELVE MONTHS ENDED 2015 NORTHWESTERN ENERGY **NATURAL GAS UTILITY**	BATTLE CREEK UTILITY	BATTLE CREEK VARIABLE	BATTLE CREEK FIXED	REVENUE & REVENUE RELATED ADJUSTMENT	SALES & ADMINISTRATIVE & GENERAL ADJUSTMENT	LABOR ADJUSTMENT	ONE-TIME ADJUSTMENT	DEPRECIATION AND DEPLETION ADJUSTMENT
48 Customer Advances for Construction/CIAC	0	0	$0	0	0	0	0	0
49 Repairs Expense	0	0	$0	0	0	0	0	0
50 Accrued Incentive Compensation	0	0	$0	0	0	0	0	0
51 MPSC/MCC Taxes	0	0	$0	0	0	0	0	0
52 Costs of Refinancing Debt	0	0	$0	0	0	0	0	0
53 Accelerated Depreciation-Excess BLM Tx vs Bk Dep	106,694	0	$106,694	0	0	0	0	0
54 Accelerated Depreciation-Excess Tx Rtn vs BLM Tx	(411,033)	0	($411,033)	0	0	0	0	(278,838)
55 Removal Costs Net of Salvage	0	0	$0	0	0	0	0	0
56 Deferred Revenue	0	0	$0	0	0	0	0	0
57 FAS106 & 112 Post Retirement Benefits	0	0	$0	0	0	0	0	0
58 Environmental Reserve	0	0	$0	0	0	0	0	0
59 Injuries & Damages	0	0	$0	0	0	0	0	0
60 Net Operating Loss	(1,196,008)	4,933	($1,200,941)	106,101	871	6,911	(847)	0
61 Excludable Foreign Income	0	0	$0	0	0	0	0	0
62 MT Corporation License Tax	18,637	0	$18,637	0	0	0	0	0
63 Deduct Interest Charges	(326)	0	($326)	0	0	0	0	0
64 Total Tax Additons / (Deductions)	($1,482,036)	$4,933	($1,486,969)	$106,101	$871	$6,911	($847)	($278,838)
65 Federal Taxable Income	$ (257,471)	$ -	$ (257,471)	$ -	$ -	$ -	$ -	$ -
66 Federal Income Tax @ 35%	($90,115)	$0	($90,115)	$0	$0	$0	$0	$0
67 Foreign Income Tax	0	0	$0	0	0	0	0	0
68 Foreign Income Tax Credit	0	0	$0	0	0	0	0	0
69 Non-Jurisdictional Items	(565,511)	0	($565,511)	0	0	0	0	0
70 Prior Period Adjustments	(2,734)	0	($2,734)	0	0	0	0	0
71 Audit Adjustments	0	0	$0	0	0	0	0	0
72 Total Federal Income Tax	(658,360)	0	(658,360)	0	0	0	0	0
73								
74								
75 Montana Corporate License Tax								
76 Federal Taxable Income B4 MT Corp Tx Deductn & N	$ (276,108)	$ -	$ (276,108)	$ -	$ -	$ -	$ -	$ -
77 Add:								
78 Other	0	0	$ -	0	0	0	0	0
79 Other State Taxes Paid	0	0	$ -	0	0	0	0	0
80								
81 Reduction for Unitary Allocation	0	0	$ -	0	0	0	0	0
82								
83 Montana Taxable Income	($276,108)	$0	($276,108)	$0	$0	$0	$0	$0
84 Mont. Corp. Lic. Tax @ 6.75%	($18,637)	$0	($18,637)	0	0	0	0	0
85 Net Tax Adjustment	($117,523)	$0	($117,523)	$0	$0	$0	$0	$0
86 Mont. Corp. License Tax	($136,160)	$0	($136,160)	$0	$0	$0	$0	$0
87 Actual 6.75%	(18,637)	0	(18,638)	0	0	0	0	0
88								
89 Change in tax rates	0	0	$0	0	0	0	0	0
90 Non-Jurisdictional Items	(117,523)	0	($117,523)	0	0	0	0	0
91 Net Tax Adjustment	(117,523)	0	(117,523)	0	0	0	0	0

COMPUTATION OF REQUIRED RETURN AND

	ACTUAL TWELVE MONTHS ENDED 2015 NORTHWESTERN ENERGY NATURAL GAS UTILITY	I AMORTIZATION ADJUSTMENT	J ALLOCATION OF TAXES - OTHER GAS PRODUCTION ADMINISTRATION	K THAN INCOME ADJUSTMENT	L WORKING CAPITAL ADJUSTMENT	M INCOME TAX ADJUSTMENT	N INTEREST SYNCHRONIZATION ADJUSTMENT	O TOTAL UPDATES & ADJUSTMENTS	P TEST PERIOD @ PRESENT RATES	10.35% ADJUST TO ROE FROM D2012.9.94
48	Customer Advances for Construction/CIAC	0	8,799	0	0	0	0	8,799	8,799	0
49	Repairs Expense	0	0	0	0	0	0	0	0	0
50	Accrued Incentive Compensation	0	5,432	0	0	0	0	5,432	5,432	0
51	MPSC/MCC Taxes	0	1,241	0	0	0	0	1,241	1,241	0
52	Costs of Refinancing Debt	0	2,647	0	0	0	0	2,647	2,647	0
53	Accelerated Depreciation-Excess BLM Tx vs Bk Dep	0	7,676	0	0	0	0	7,676	114,371	0
54	Accelerated Depreciation-Excess Tx Rtn vs BLM Tx	(232)	(1,460,302)	0	0	0	0	(1,739,373)	(2,150,406)	0
55	Removal Costs Net of Salvage	0	0	0	0	0	0	0	0	0
56	Deferred Revenue	0	98,227	0	0	0	0	98,227	98,227	0
57	FAS106 & 112 Post Retirement Benefits	0	24,077	0	0	0	0	24,077	24,077	0
58	Environmental Reserve	0	2,183	0	0	0	0	2,183	2,183	0
59	Injuries & Damages	0	(8,926)	0	0	0	0	(8,926)	(8,926)	0
60	Net Operating Loss	0	1,899,201	2,898	0	276,108	214,143	2,505,386	1,304,445	0
61	Excludable Foreign Income	0	0	0	0	0	0	0	0	0
62	MT Corporation License Tax	0	0	0	0	(18,637)	0	(18,637)	0	0
63	Deduct Interest Charges	0	0	0	0	0	(214,143)	(214,143)	(214,469)	0
64	Total Tax Additons / (Deductions)	($232)	$583,154	$2,898	$0	$257,471	$0	$677,489	($809,480)	$0
65	Federal Taxable Income	$ -	$ 0	$ -	$ -	$ 257,471	$ -	$ 257,471	$ -	$ -
66	Federal Income Tax @ 35%	$0	$0	$0	$0	$90,115	$0	90,115	$0	$0
67	Foreign Income Tax	0	0	0	0	0	0	0	0	0
68	Foreign Income Tax Credit	0	0	0	0	0	0	0	0	0
69	Non-Jurisdictional Items	0	0	0	0	565,511	0	565,511	0	0
70	Prior Period Adjustments	0	0	0	0	2,734	0	2,734	0	0
71	Audit Adjustments	0	0	0	0	0	0	0	0	0
72	Total Federal Income Tax	0	0	0	0	658,360	0	658,360	0	0
73										
74										
75	Montana Corporate License Tax									
76	Federal Taxable Income B4 MT Corp Tx Deductn & N	$ -	$ 0	$ -	$ -	$ 276,108	$ -	276,108	0	$ -
77	Add:									
78	Other	0	0	0	0	0	0	0	0	0
79	Other State Taxes Paid	0	0	0	0	0	0	0	0	0
80										
81	Reduction for Unitary Allocation	0	0	0	0	0	0	0	0	0
82										
83	Montana Taxable Income	$0	$0	$0	$0	$276,108	$0	276,108	0	$0
84	Mont. Corp. Lic. Tax @ 6.75%	0	0	0	0	18,637	0	18,637	0	0
85	Net Tax Adjustment	$0	$0	$0	$0	$117,523	$0	117,523	0	$0
86	Mont. Corp. License Tax	$0	$0	$0	$0	$136,160	$0	$136,160	$0	$0
87	Actual 6.75%	0	0	0	0	18,637	0	18,637	(1)	0
88										
89	Change in tax rates	0	0	0	0	0	0	0	0	0
90	Non-Jurisdictional Items	0	0	0	0	117,523	0	117,523	0	0
91	Net Tax Adjustment	0	0	0	0	117,523	0	117,523	0	0

COMPUTATION OF REQUIRED RETURN AND

GENERAL RATE CASE

		Q	R	S	T	U	V
		INTERIM ADJUSTMENTS					
	ACTUAL TWELVE MONTHS ENDED 2015 NORTHWESTERN ENERGY **NATURAL GAS UTILITY**	DEPRECIATION ADJUSTMENT	WORKING CAPITAL ADJUSTMENT	INCOME TAX ADJUSTMENT	INTEREST YNCHRONIZATIO ADJUSTMENT	INTERIM TOTAL UPDATES & ADJUSTMENTS	INTERIM TEST PERIOD @ PRESENT RATES
48	Customer Advances for Construction/CIAC	0	0	0	0	0	8,799
49	Repairs Expense	0	0	0	0	0	0
50	Accrued Incentive Compensation	0	0	0	0	0	5,432
51	MPSC/MCC Taxes	0	0	0	0	0	1,241
52	Costs of Refinancing Debt	0	0	0	0	0	2,647
53	Accelerated Depreciation-Excess BLM Tx vs Bk Dep	0	0	0	0	0	114,371
54	Accelerated Depreciation-Excess Tx Rtn vs BLM Tx	(123)	0	0	0	(123)	(2,150,529)
55	Removal Costs Net of Salvage	0	0	0	0	0	0
56	Deferred Revenue	0	0	0	0	0	98,227
57	FAS106 & 112 Post Retirement Benefits	0	0	0	0	0	24,077
58	Environmental Reserve	0	0	0	0	0	2,183
59	Injuries & Damages	0	0	0	0	0	(8,926)
60	Net Operating Loss	0	0	(0)	(1)	(1)	1,304,444
61	Excludable Foreign Income	0	0	0	0	0	0
62	MT Corporation License Tax	0	0	0	0	0	0
63	Deduct Interest Charges	0	0	0	1	1	(214,469)
64	Total Tax Additons / (Deductions)	($123)	$0	($0)	$0	($123)	($809,603)
65	Federal Taxable Income	$ -	$ -	$ (0)	$ -	$ (0)	$ -
66	Federal Income Tax @ 35%	$0	$0	$0	$0	0	$0
67	Foreign Income Tax	0	0	0	0	0	0
68	Foreign Income Tax Credit	0	0	0	0	0	0
69	Non-Jurisdictional Items	0	0	0	0	0	0
70	Prior Period Adjustments	0	0	0	0	0	0
71	Audit Adjustments	0	0	0	0	0	0
72	Total Federal Income Tax	0	0	0	0	0	0
73							
74							
75	Montana Corporate License Tax						
76	Federal Taxable Income B4 MT Corp Tx Deductn & N	$ -	$ -	$ (0)	$ -	(0)	(0)
77	Add:						
78	Other	0	0	0	0	0	0
79	Other State Taxes Paid	0	0	0	0	0	0
80							
81	Reduction for Unitary Allocation	0	0	0	0	0	0
82							
83	Montana Taxable Income	$0	$0	($0)	$0	(0)	(0)
84	Mont. Corp. Lic. Tax @ 6.75%	0	0	0	0	0	0
85	Net Tax Adjustment	$0	$0	$0	$0	0	0
86	Mont. Corp. License Tax	$0	$0	$0	$0	0	0
87	Actual 6.75%	0	0	0	0	0	(1)
88							
89	Change in tax rates	0	0	0	0	0	0
90	Non-Jurisdictional Items	0	0	0	0	0	0
91	Net Tax Adjustment	0	0	0	0	0	0

COMPUTATION OF REQUIRED RETURN AND

GENERAL RATE CASE	A	B	C	D	E	F	G	H
ACTUAL TWELVE MONTHS ENDED 2015 NORTHWESTERN ENERGY **NATURAL GAS UTILITY** REVENUE INCREASE	BATTLE CREEK UTILITY	BATTLE CREEK VARIABLE	BATTLE CREEK FIXED	REVENUE & REVENUE RELATED ADJUSTMENT	SALES & ADMINISTRATIVE & GENERAL ADJUSTMENT	LABOR ADJUSTMENT	ONE-TIME ADJUSTMENT	DEPRECIATION AND DEPLETION ADJUSTMENT
1 Electric Utility Rate Base			$8,579,130	$0	$0	$0	$0	$61,225
2 Rate of Return			7.33%	7.33%	7.33%	7.33%	7.33%	7.33%
3								
4								
5 Net Operating Income			628,850	0	0	0	0	4,488
6								
7 Net Operating Income for the Year								
8 Ended 12/31/15 Adjusted for Known Changes			841,624	(64,311)	(528)	(4,189)	513	181,245
9								
10 **Required Incremental Increase in Net**								
11 **Operating Income**			**($212,774)**	**$64,311**	**$528**	**$4,189**	**($513)**	**($176,757)**
12								
13 Add:								
14 MPSC Tax			(1,376)	416	3	27	(3)	(1,143)
15 Consumer Counsel Tax			(353)	107	1	7	(1)	(293)
16 Incremental Income Taxes			(138,266)	41,791	343	2,723	(333)	(114,861)
17								
18 **Required Revenue Increase**			**($352,769)**	**$106,625**	**$875**	**$6,946**	**($850)**	**($293,054)**
19								
20								
21 MPSC Tax (0.39%)			(1,376)	416	3	27	(3)	(1,143)
22								
23 Consumer Counsel Tax (0.10%)			(353)	107	1	7	(1)	(293)
24								
25 Taxable Income for State Income Tax			($351,040)	$106,102	$871	$6,912	($846)	($291,618)
26								
27 State Income Tax (6.75%) (Unitary Factor = 1.00)			(23,695)	7,162	59	467	(57)	(19,684)
28								
29 Taxable Income for Federal Income Tax			($327,345)	$98,940	$812	$6,445	($789)	($271,934)
30								
31 Reduction of Fed.Inc.Tax-Due to MCLT Expense			8,293	(2,507)	(21)	(163)	20	6,889
32 Federal Income Tax Expense (35%)			(122,864)	37,136	305	2,419	(296)	(102,066)
33								
34 **Required Incremental Increase in Net**								
35 **Operating Income**			**($212,774)**	**$64,311**	**$528**	**$4,189**	**($513)**	**($176,757)**

GENERAL RATE CASE

	ACTUAL TWELVE MONTHS ENDED 2015 NORTHWESTERN ENERGY **NATURAL GAS UTILITY** REVENUE INCREASE	I AMORTIZATION ADJUSTMENT	J ALLOCATION OF TAXES - OTHER GAS PRODUCTION ADMINISTRATION	K THAN INCOME ADJUSTMENT	L WORKING CAPITAL ADJUSTMENT	M INCOME TAX ADJUSTMENT	N INTEREST SYNCHRONIZATION ADJUSTMENT	O TOTAL UPDATES & ADJUSTMENTS	P TEST PERIOD @ PRESENT RATES	10.35% ADJUST TO ROE FROM D2012.9.94
1	Electric Utility Rate Base	($582)	$0	$0	($241,893)	$215,341	$0	$34,091	$8,613,221	$8,613,221
2	Rate of Return	7.33%	7.33%	7.33%	7.33%	7.33%	7.33%	7.33%	7.33%	-0.25%
3										
4										
5	Net Operating Income	(43)	0	0	(17,731)	15,784	0	2,499	631,349	(21,533)
6										
7	Net Operating Income for the Year									
8	Ended 12/31/15 Adjusted for Known Changes	151	(293,558)	(1,757)	0	(120,257)	84,346	(218,345)	623,279	0
9										
10	**Required Incremental Increase in Net**									
11	**Operating Income**	**($194)**	**$293,558**	**$1,757**	**($17,731)**	**$136,041**	**($84,346)**	**$220,843**	**$8,069**	**($21,533)**
12										
13	Add:									
14	MPSC Tax	(1)	1,898	11	(115)	880	(545)	1,428	52	(139)
15	Consumer Counsel Tax	0	487	3	(29)	226	(140)	368	15	(36)
16	Incremental Income Taxes	(126)	190,762	1,142	(11,522)	88,403	(54,810)	143,512	5,246	(13,993)
17										
18	**Required Revenue Increase**	**($321)**	**$486,705**	**$2,913**	**($29,397)**	**$225,550**	**($139,841)**	**$366,151**	**$13,382**	**($35,701)**
19										
20										
21	MPSC Tax (0.39%)	(1)	1,898	11	(115)	880	(545)	1,428	52	(139)
22										
23	Consumer Counsel Tax (0.10%)	0	487	3	(29)	226	(140)	368	15	(36)
24										
25	Taxable Income for State Income Tax	($320)	$484,320	$2,899	($29,253)	$224,444	($139,156)	364,355	13,315	($35,526)
26										
27	State Income Tax (6.75%) (Unitary Factor = 1.00)	(22)	32,692	196	(1,975)	15,150	(9,393)	24,595	900	(2,398)
28										
29	Taxable Income for Federal Income Tax	($298)	$451,628	$2,703	($27,278)	$209,294	($129,763)	$339,760	$12,415	($33,128)
30										
31	Reduction of Fed.Inc.Tax-Due to MCLT Expense	8	(11,442)	(69)	691	(5,303)	3,288	(8,609)	(316)	839
32	Federal Income Tax Expense (35%)	(112)	169,512	1,015	(10,238)	78,556	(48,705)	127,526	4,662	(12,434)
33										
34	**Required Incremental Increase in Net**									
35	**Operating Income**	**($194)**	**$293,558**	**$1,757**	**($17,731)**	**$136,041**	**($84,346)**	**$220,843**	**$8,069**	**($21,533)**

GENERAL RATE CASE

ACTUAL TWELVE MONTHS ENDED 2015
NORTHWESTERN ENERGY
NATURAL GAS UTILITY
REVENUE INCREASE

		Q	R	S	T	U	V
		INTERIM ADJUSTMENTS					
		DEPRECIATION ADJUSTMENT	WORKING CAPITAL ADJUSTMENT	INCOME TAX ADJUSTMENT	INTEREST YNCHRONIZATIO ADJUSTMENT	INTERIM TOTAL UPDATES & ADJUSTMENTS	INTERIM TEST PERIOD @ PRESENT RATES
1	Electric Utility Rate Base	$0	$0	($22)	$0	($22)	$8,613,199
2	Rate of Return	7.08%	7.08%	7.08%	7.08%	7.08%	7.08%
3							
4							
5	Net Operating Income	0	0	(2)	0	(2)	609,815
6							
7	Net Operating Income for the Year						
8	Ended 12/31/15 Adjusted for Known Changes	80	0	0	0	80	623,359
9							
10	**Required Incremental Increase In Net**						
11	**Operating Income**	**($80)**	**$0**	**($2)**	**$0**	**($21,615)**	**($13,546)**
12							
13	Add:						
14	MPSC Tax	(1)	0	0	0	(140)	(88)
15	Consumer Counsel Tax	0	0	0	0	(36)	(21)
16	Incremental Income Taxes	(52)	0	(1)	0	(14,046)	(8,800)
17							
18	**Required Revenue Increase**	**($133)**	**$0**	**($3)**	**$0**	**($35,837)**	**($22,455)**
19							
20							
21	MPSC Tax (0.39%)	(1)	0	0	0	(140)	(88)
22							
23	Consumer Counsel Tax (0.10%)	0	0	0	0	(36)	(21)
24							
25	Taxable Income for State Income Tax	($132)	$0	($3)	$0	(35,661)	(22,346)
26							
27	State Income Tax (6.75%) (Unitary Factor = 1.00)	(9)	0	0	0	(2,407)	(1,507)
28							
29	Taxable Income for Federal Income Tax	($123)	$0	($3)	$0	($33,254)	($20,839)
30							
31	Reduction of Fed.Inc.Tax-Due to MCLT Expense	3	0	0	0	842	526
32	Federal Income Tax Expense (35%)	(46)	0	(1)	0	(12,481)	(7,819)
33							
34	**Required Incremental Increase in Net**						
35	**Operating Income**	**($80)**	**$0**	**($2)**	**$0**	**($21,615)**	**($13,546)**

	A	B	C	D	E	F	G	H
1		**NorthWestern Energy**						
2		**Natural Gas Utility**						
3		**Derivation of Uniform Percentage Change**						
4								
5		**Docket No. D2016.9.68**						
6		**Interim**						
7								
8								
9								
10								
11								
12				Revenues @ Current Base Rates		Change		Uniform Percentage Change
13								
14								
15		Total Revenues		$ 114,477,601				
16								
17		Transportation Contract Revenue Adjustment		$ -				
18								
19		Derivation of Rates Total Revenues		$ 114,477,601		$ 5,596,577		4.8888%
20								
21		Rounding Base Rates to Nearest Nickel				$ -		
22								
23		Adjusted Uniform Percent Change		$ 114,477,601		$ 5,596,577		4.8888%

NorthWestern Energy
Natural Gas Utility
Derivation of Class Revenue Responsibility

Docket No. D2016.9.68
Interim

	Revenues @ Current Base Rates	Uniform % Change 4.89%	Class Revenue Responsibility
Core - DBU			
Residential	$ 60,917,760	$ 2,985,327	$ 63,903,086
General Service	$ 31,817,779	$ 1,553,061	$ 33,370,841
Total Core - DBU	$ 92,735,539	$ 4,538,388	$ 97,273,927
Utility	$ 330,096	$ 16,138	$ 346,234
Non-Core			
DBU Transportation			
Firm Transportation	$ 2,408,640	$ 117,774	$ 2,526,414
Interruptible Transportation	$ 34,448	$ 1,684	$ 36,133
TBU Transportation			
Firm Transportation	$ 13,006,109	$ 630,112	$ 13,636,220
Interruptible Transportation	$ 2,442,349	$ 119,403	$ 2,561,752
Storage	$ 3,520,419	$ 172,097	$ 3,692,516
Total Montana (Distr., Transp & Storage)	$ 114,477,601	$ 5,595,595	$ 120,073,196

NorthWestern Energy
Natural Gas Utility
Derivation of Proposed Tariff Rates

NorthWestern Energy

Line No.	(A)	(B) Docket No. D2015.10.81 Order No. 7451a Without Tax Deferred	(C) 4.8888% Uniform % Increase	(D) Interim Proposed Rates
1	**Core Sales Service:**			
2	**Residential Natural Gas Service**			
3	D-RG-1 Rate Schedule			
4	Monthly Service Charge per Meter	$ 7.29	$ 0.36	$ 7.65
5	Commodity Charges:			
6	Distribution	$ 2.098629	$ 0.102598	$ 2.201227
7	Transmission	$ 1.242724	$ 0.060754	$ 1.303478
8	Storage	$ 0.378218	$ 0.018490	$ 0.396708
9	Total Commodity Charge	$ 3.719571		$ 3.901413
10				
11				
12	**General Natural Gas Service**			
13	Monthly Service Charge per Meter			
14	0 to 300	$ 18.94	$ 0.93	$ 19.85
15	301 to 1,000	$ 24.99	$ 1.22	$ 26.20
16	1,001 to 2,000	$ 40.26	$ 1.97	$ 42.25
17	2,001 to 5,000	$ 67.59	$ 3.30	$ 70.90
18	5,001 to 10,000	$ 83.05	$ 4.06	$ 87.10
19	10,001 to 30,000	$ 131.25	$ 6.42	$ 137.65
20	> 30,000	$ 159.48	$ 7.80	$ 167.30
21	Commodity Charges:			
22	Distribution	$ 2.028941	$ 0.099191	$ 2.128132
23	Transmission	$ 1.201183	$ 0.058723	$ 1.259906
24	Storage	$ 0.364751	$ 0.017832	$ 0.382583
25	Total Commodity Charge	$ 3.594875		$ 3.770621
26				
27	**Firm Utility Gas Contract Service**			
28	Monthly Service Charge per Meter			
29	10,001 to 30,000	$ 127.78	$ 6.25	$ 134.05
30	> 30,000	$ 329.40	$ 16.10	$ 345.50
31				
32	Transmission Charges:			
33	Reservation Rate (MDDQ)	$ 6.220535	$ 0.304109	$ 6.524644
34	Transmission Commodity Rate (Dkt)	$ 0.074147	$ 0.003625	$ 0.077772
35				
36	Storage Charges:			
37	Reservation Rate (MDDQ)	$ 4.947281	$ 0.241863	$ 5.189144
38	Storage Commodity Rate (Dkt)	$ 0.017897	$ 0.000875	$ 0.018772

NorthWestern Energy
Natural Gas Utility
Derivation of Proposed Tariff Rates

NorthWestern Energy

Line No.	(A)	(B) Docket No. D2015.10.81 Order No. 7451a Without Tax Deferred	(C) 4.8888% Uniform % Increase	(D) Interim Proposed Rates
1	**Noncore: Transportation Service**			
2	Monthly Service Charge per Meter			
3	Distribution Level Meter Charges:			
4	2,000 to 5,000	$ 122.34	$ 5.98	$ 128.30
5	5,001 to 10,000	$ 139.80	$ 6.83	$ 146.65
6	10,001 to 30,000	$ 192.19	$ 9.40	$ 201.60
7	> 30,000	$ 223.22	$ 10.91	$ 234.15
8				
9	Transmission Level Meter Charges:			
10	5,001 to 10,000	$ 119.71	$ 5.85	$ 125.55
11	10,001 to 30,000	$ 172.08	$ 8.41	$ 180.50
12	> 30,000	$ 381.83	$ 18.67	$ 400.50
13				
14	**Firm Distribution**			
15	D-FTG-1 Rate Schedule			
16	Monthly Reservation Rate/Trans. MDDQ	$ 7.739992	$ 0.378392	$ 8.118384
17				
18	**Interruptible Distribution**			
19	D-ITG-1 Rate Schedule			
20	Commodity Charge - Maximum	$ 0.254495	$ 0.012442	$ 0.266937
21	Commodity Charge - Minimum	$ 0.017935		$ 0.017935
22				
23	**Firm Transmission**			
24	T-FTG-1 Rate Schedule			
25	Reservation Charge	$ 9.784615	$ 0.478350	$ 10.262965
26	Commodity Charge - Maximum	$ 0.074147	$ 0.003625	$ 0.077772
27	Commodity Charge - Minimum	$ 0.017935		$ 0.017935
28				
29	**Interruptible Transmission**			
30	T-ITG-1 Rate Schedule			
31	Commodity Charge - Maximum	$ 0.395798	$ 0.019350	$ 0.415148
32	Commodity Charge - Minimum	$ 0.017935		$ 0.017935
33				
34	**Firm Storage**			
35	T-FSG-1 Rate Schedule			
36	Withdrawal Reservation Charge	$ 4.675642	$ 0.228583	$ 4.904225
37	Capacity Commodity Charge	$ 0.022955	$ 0.001122	$ 0.024077
38	Injection Commodity Charge	$ 0.024163	$ 0.001181	$ 0.025344
39	Withdrawal Commodity Charge	$ 0.024163	$ 0.001181	$ 0.025344

NorthWestern Energy

NorthWestern Energy
Natural Gas Utility
12 Months Ended December 2015

Natural Gas Revenue Summary
Interim

	A	B	C	D	E	F	L	M	N	O	P	Q	R
7		**Actual**					**Test Period**						
9		Avg. Cust. Nos.	MDDQ	Market (Dkt)	Revenues @ Current Base Rates		Avg. Cust. Nos.	MDDQ	Market (Dkt)	Revenues @ Current Base Rates	Revenues @ Uniform Design InterimRates	Revenue Change (P) vs. (Q)	Percent Change (P) vs. (Q)
10	**Core - DBU**												
11	RESIDENTIAL:												
12	Residential	165,787		11,684,807	$ 57,965,500		165,787		12,452,351	$ 60,820,434	$ 63,800,994	$ 2,980,559	4.90%
13	Employee	284		26,584	$ 92,799		284		28,206	$ 97,326	$ 102,093	$ 4,767	4.90%
14	Subtotal	166,071		11,711,391	$ 58,058,299		166,071		12,480,557	$ 60,917,760	$ 63,903,086	$ 2,985,327	4.90%
15													
16	GENERAL SERVICE:												
17	Commercial	22,943		6,162,105	$ 29,383,581		22,943		6,512,452	$ 30,643,035	$ 32,138,686	$ 1,495,651	4.88%
18	Industrial Firm	263		151,636	$ 646,027		263		160,252	$ 677,000	$ 710,079	$ 33,079	4.89%
19	G & M	90		56,630	$ 245,456		90		60,404	$ 259,026	$ 271,689	$ 12,663	4.89%
20	Interdepart.	62		55,377	$ 226,324		62		58,825	$ 238,718	$ 250,386	$ 11,668	4.89%
21	Total - Gen. Ser.	23,359		6,425,748	$ 30,501,387		23,359		6,791,933	$ 31,817,779	$ 33,370,841	$ 1,553,061	4.88%
22													
23	**Total Core - DBU**	189,430		18,137,138	$ 88,559,687		189,430		19,272,490	$ 92,735,539	$ 97,273,927	$ 4,538,388	4.89%
24													
25	**Utilities**	4		209,502	$ 327,850		4		233,901	$ 330,096	$ 346,234	$ 16,138	4.89%
26	Transmission		2,751					2,751					
27	Storage		1,513					1,513					
28													
29	**Non-Core**												
30	DBU Transportation												
31	Firm Transportation	224	21,403		$ 2,386,159		224	21,403		$ 2,408,640	$ 2,526,414	$ 117,774	4.89%
32	Interruptible Transportation			135,360	$ 34,448				135,360	$ 34,448	$ 36,133	$ 1,684	4.89%
33													
34	TBU Transportation												
35	Firm Transportation	32	101,220	17,506,478	$ 13,006,109		32	101,220	17,506,478	$ 13,006,109	$ 13,636,220	$ 630,112	4.84%
36	Interruptible Transportation			6,035,341	$ 2,442,349				6,035,341	$ 2,442,349	$ 2,561,752	$ 119,403	4.89%
37													
38	Storage		45,740		$ 3,520,419			45,740		$ 3,520,419	$ 3,692,516	$ 172,097	4.89%
39													
40	**Total Montana (Distr., Transp & Storage)**	189,690		42,023,819	$ 110,277,021		189,690		43,183,570	$ 114,477,601	$ 120,073,196	$ 5,595,595	4.89%
41													
42	Off-System IT			131,647	$ 12,487				131,647	$ 12,487	$ 12,487	$ -	
43													
44													
45	CMPL Transportation				$ 170,464					$ 170,464	$ 170,464	$ -	
46													
47	Miscellaneous Revenues				$ 1,149,823					$ 613,520	$ 613,520	$ -	
48													
49	Rounding										982	$ 982	
50													
51	Total	189,690		42,155,466	$ 111,609,795		189,690		43,315,217	$ 115,274,072	$ 120,870,649	$ 5,596,577	4.86%
52													

NorthWestern Energy

NorthWestern Energy
12 Months Ended December 2015
Natural Gas Utility

Number of Customers

Line No.	(A)	(B) Total	(C) January	(D) February	(E) March	(F) April	(G) May	(H) June	(I) July	(J) August	(K) September	(L) October	(M) November	(N) December
1	**Core - DBU**													
2														
3	RESIDENTIAL:													
4	Residential	165,787	165,179	165,296	165,505	165,644	165,691	165,666	165,533	165,467	165,646	166,097	166,652	167,066
5	Employee	284	293	292	290	289	288	284	282	280	280	278	278	275
6	Total - Residential	166,071	165,472	165,588	165,795	165,933	165,979	165,950	165,815	165,747	165,926	166,375	166,930	167,341
7														
8	General Service:													
9	Commercial 0 - 300	14,929	15,237	15,253	15,277	15,206	15,169	15,120	15,035	14,378	14,498	14,546	14,665	14,763
10	301 - 1,000	3,269	3,155	3,155	3,161	3,206	3,200	3,199	3,197	3,397	3,365	3,384	3,399	3,413
11	1,001 - 2,000	3,241	3,057	3,062	3,071	3,119	3,126	3,126	3,123	3,404	3,448	3,435	3,452	3,468
12	2,001 - 5,000	1,204	1,205	1,214	1,214	1,208	1,210	1,216	1,215	1,291	1,194	1,161	1,159	1,166
13	5,001 - 10,000	273	260	262	262	263	262	263	262	287	262	296	295	296
14	10,001 - 30,000	25	22	22	22	22	22	22	23	24	19	32	33	33
15	> 30,000	3	3	3	3	3	3	3	3	3	2	2	2	2
16	Total Commercial	22,943	22,939	22,971	23,010	23,027	22,992	22,949	22,858	22,784	22,788	22,856	23,005	23,141
17														
18	Indust. Firm 0 - 300	126	128	127	127	127	127	127	126	122	126	126	127	127
19	301 - 1,000	54	53	53	53	55	54	55	55	54	54	54	53	53
20	1,001 - 2,000	51	50	50	50	50	50	49	49	54	52	53	53	53
21	2,001 - 5,000	20	19	19	18	19	18	18	18	19	22	22	22	22
22	5,001 - 10,000	6	8	8	8	8	8	8	8	8	3	3	3	3
23	10,001 - 30,000	4	4	4	4	4	4	3	3	3	4	4	4	4
24	> 30,000	2	2	2	2	2	2	2	2	2	1	1	1	1
25	Total Indust. Firm	263	264	263	262	265	263	262	261	262	262	263	263	263
26														
27	G & M 0 - 300	32	31	31	31	31	31	31	31	31	33	33	33	35
28	301 - 1,000	11	11	11	11	11	11	11	11	10	12	12	12	12
29	1,001 - 2,000	30	31	31	31	31	31	31	31	31	27	27	27	27
30	2,001 - 5,000	11	12	11	12	12	12	11	12	12	12	8	8	8
31	5,001 - 10,000	4	3	3	3	3	3	3	3	5	4	6	5	5
32	10,001 - 30,000	3	2	2	2	2	2	2	2	2	2	5	5	5
33	Total G & M	90	90	89	90	90	90	89	90	91	90	91	90	92
34														
35	Interdepart. 0 - 300	26	26	26	26	26	26	26	26	27	27	27	27	27
36	301 - 1,000	9	10	10	10	10	10	10	10	7	7	7	7	7
37	1,001 - 2,000	15	14	14	14	14	13	13	13	16	17	17	17	17
38	2,001 - 5,000	8	8	8	8	8	9	9	9	7	7	7	7	7
39	5,001 - 10,000	4	3	3	3	3	3	3	3	5	4	4	4	4
40	10,001 - 30,000	1	1	1	1	1	1	1	1	1	1	1	1	1
41	Total Interdepart.	62	62	62	62	62	62	62	62	63	63	63	63	63
42														
43	Total General Service	23,359	23,355	23,385	23,424	23,444	23,407	23,362	23,271	23,200	23,203	23,273	23,421	23,559
44														
45	**Core TBU: Utilities**													
46	10001 to 30000	1	1	1	1	1	1	1	1	1	1	1	1	1
47	> 30000	3	3	3	3	3	3	3	3	3	3	3	3	3
48		4	4	4	4	4	4	4	4	4	4	4	4	4

NorthWestern Energy

NorthWestern Energy
12 Months Ended December 2015
Natural Gas Utility

Number of Customers

Line No.	(A)	(B) Total	(C) January	(D) February	(E) March	(F) April	(G) May	(H) June	(I) July	(J) August	(K) September	(L) October	(M) November	(N) December
49	**Non-Core DBU: Firm**													
50	< 5000	48	48	48	48	48	48	48	48	48	48	48	48	48
51	5000 to 10000	101	102	102	102	102	101	101	101	101	101	101	101	100
52	10001 to 30000	56	56	56	56	56	56	56	56	56	56	56	57	57
53	> 30000	19	19	19	19	19	19	19	19	19	19	19	19	19
54		224	225	225	225	225	224	224	224	224	224	224	225	224
55														
56	**Non-Core DBU: Interruptible**													
57	< 5000	-	-	-	-	-	-	-	-	-	-	-	-	-
58	5000 to 10000	-	-	-	-	-	-	-	-	-	-	-	-	-
59	10001 to 30000	-	-	-	-	-	-	-	-	-	-	-	-	-
60	> 30000	-	-	-	-	-	-	-	-	-	-	-	-	-
61		-	-	-	-	-	-	-	-	-	-	-	-	-
62														
63	**Non-Core TBU: Firm**													
64	5000 to 10000	2	2	2	2	2	2	2	2	2	2	2	2	2
65	10001 to 30000	6	6	6	6	6	6	6	6	6	6	6	6	6
66	> 30000	24	25	25	25	25	24	24	23	23	23	23	23	23
67		32	33	33	33	33	32	32	31	31	31	31	31	31
68														
69	**Non-Core TBU: Interruptible**													
70														
71	5000 to 10000	-	-	-	-	-	-	-	-	-	-	-	-	-
72	10001 to 30000	-	-	-	-	-	-	-	-	-	-	-	-	-
73	> 30000	-	-	-	-	-	-	-	-	-	-	-	-	-
74		-	-	-	-	-	-	-	-	-	-	-	-	-
75														
76	Total Core & Non-Core	189,690	189,089	189,235	189,481	189,639	189,646	189,572	189,345	189,206	189,388	189,907	190,611	191,159

NorthWestern Energy

NorthWestern Energy
Natural Gas Utility
12 Months Ended December 2015

Actual Consumption
MDDQ's & Dekatherms

Line No.	(A)	(B) Units	(C) TOTAL	(D) January	(E) February	(F) March	(G) April	(H) May	(I) June	(J) July	(K) August	(L) September	(M) October	(N) November	(O) December
1	**Core - DBU**														
2	RESIDENTIAL:														
3	Residential	Dkt	11,684,807	2,208,260	1,621,253	1,546,149	1,030,625	754,252	447,518	244,104	243,315	304,813	449,530	951,873	1,883,113
4	Employee	Dkt	26,584	4,836	3,697	3,539	2,449	1,932	1,215	527	562	661	1,044	2,070	4,055
5	Subtotal		11,711,391	2,213,096	1,624,950	1,549,688	1,033,074	756,184	448,732	244,631	243,876	305,474	450,575	953,942	1,887,168
6															
7	GENERAL SERVICE:														
8	Commercial	Dkt	6,162,105	1,149,384	837,268	784,135	529,637	392,875	251,956	178,109	174,229	191,378	240,943	481,420	950,769
9	Industrial Firm	Dkt	151,636	24,685	30,511	20,106	11,550	8,850	5,695	4,744	4,771	5,944	6,071	10,464	18,245
10	G & M	Dkt	56,630	11,516	5,631	7,131	4,916	3,784	2,171	872	1,770	1,706	2,390	5,669	9,074
11	Interdepart.	Dkt	55,377	10,098	7,226	6,941	5,349	3,680	2,717	1,465	1,458	1,665	2,159	4,436	8,182
12	Total - Gen. Ser.		6,425,748	1,195,684	880,636	818,313	551,452	409,189	262,539	185,191	182,228	200,693	251,563	501,988	986,270
13															
14	Core Market (Residential & General Service)		18,137,138	3,408,781	2,505,586	2,368,001	1,584,526	1,165,374	711,271	429,822	426,104	506,167	702,138	1,455,931	2,873,438
15															
16	Core - S&TBU: Utilities	Dkt	209,502	35,588	37,749	29,994	22,247	15,624	9,631	4,207	3,746	3,839	6,395	12,981	27,501
17	Transmission	MDDQ	33,012	2,751	2,751	2,751	2,751	2,751	2,751	2,751	2,751	2,751	2,751	2,751	2,751
18	Storage	MDDQ	18,156	1,513	1,513	1,513	1,513	1,513	1,513	1,513	1,513	1,513	1,513	1,513	1,513
19															
20	**Total Core Market**	Dkt	18,346,640	3,444,369	2,543,335	2,397,995	1,606,773	1,180,998	720,902	434,029	429,850	510,006	708,533	1,468,912	2,900,939
21															
22															
23	**Non-Core Market**														
24															
25	DBU Firm Transportation														
26	Firm Reservation	MDDQ	256,833	21,501	21,433	21,433	21,433	21,367	21,367	21,367	21,367	21,367	21,391	21,415	21,392
27	Interruptible Commodity	Dkt	135,360	23,597	30,899	21,818	14,766	4,838	2,443	2,162	3,214	3,035	5,708	5,878	17,002
28															
29	TBU Firm Transportation														
30	Firm Reservation	MDDQ	1,214,639	98,529	98,461	98,461	98,461	98,395	98,395	98,140	103,140	108,140	108,164	108,188	98,165
31	Firm Transportation	Dkt	17,506,478	2,006,995	2,034,017	1,713,150	1,609,036	1,243,340	1,119,243	915,826	1,092,424	1,227,707	1,288,514	1,522,591	1,733,635
32	Interrup Transportation	Dkt	6,035,341	494,791	419,793	475,233	476,987	428,075	492,083	450,033	506,627	656,324	548,092	562,941	524,362
33															
34	TBU Firm Storage														
35	Withdrawal Reservation	MDDQ	548,885	48,582	48,535	48,535	48,535	50,919	43,519	43,345	43,345	43,345	43,359	43,381	43,485
36	Injection Commodity	Dkt	3,200,683	4,003	3,459	3,516	11,012	358,760	362,637	676,614	420,305	719,961	312,462	198,601	129,353
37	Withdrawal Commodity	Dkt	3,245,988	567,503	1,200,183	805,799	400,267	7,320	658	506	32,977	545	527	750	228,953
38	Storage Capacity	Dkt	34,774,851	3,579,907	2,383,183	1,670,900	1,221,645	1,573,085	1,935,064	2,727,476	3,114,804	3,834,220	4,146,155	4,344,006	4,244,406
39															
40	Total Montana	Dkt	42,023,819	5,969,752	5,028,044	4,608,196	3,707,562	2,857,251	2,334,671	1,802,050	2,032,115	2,397,072	2,550,847	3,560,322	5,175,938

NorthWestern Energy

NorthWestern Energy
Natural Gas Utility
12 Months Ended December 2015
Distribution, Transmission & Storage

Actual Revenue at Current Base Rates

Line No.	(A)	(B) Total	(C) January	(D) February	(E) March	(F) April	(G) May	(H) June	(I) July	(J) August	(K) September	(L) October	(M) November	(N) December
1	**CORE:**													
2	RESIDENTIAL:													
3	Residential	$ 57,965,500	$ 9,417,936	$ 7,235,374	$ 6,957,543	$ 5,041,029	$4,013,382	$2,872,279	$2,114,697	$2,111,281	$2,341,334	$2,882,907	$4,755,452	$ 8,222,285
4	Employee	$ 92,799	$ 15,093	$ 11,909	$ 11,457	$ 8,411	$ 6,964	$ 4,941	$ 3,012	$ 3,097	$ 3,373	$ 4,433	$ 7,293	$ 12,815
5	Subtotal	$ 58,058,299	$ 9,433,029	$ 7,247,284	$ 6,969,000	$ 5,049,440	$4,020,346	$2,877,219	$2,117,709	$2,114,379	$2,344,708	$2,887,340	$4,762,745	$ 8,235,100
6														
7	GENERAL SERVICE:													
8	Commercial	$ 29,383,581	$ 4,728,805	$ 3,608,065	$ 3,418,026	$ 2,504,526	$2,012,369	$1,505,316	$1,238,047	$1,235,309	$1,290,756	$1,472,094	$2,339,805	$ 4,030,464
9	Industrial Firm	$ 646,027	$ 97,295	$ 118,218	$ 80,746	$ 50,107	$ 40,308	$ 28,819	$ 25,382	$ 25,646	$ 29,617	$ 30,116	$ 45,900	$ 73,873
10	G & M	$ 245,456	$ 44,832	$ 23,608	$ 29,068	$ 21,105	$ 17,034	$ 11,170	$ 6,568	$ 9,938	$ 9,551	$ 12,299	$ 24,002	$ 36,281
11	Interdepart.	$ 226,324	$ 38,529	$ 28,205	$ 27,177	$ 21,457	$ 15,484	$ 12,021	$ 7,521	$ 7,592	$ 8,293	$ 10,068	$ 18,255	$ 31,720
12	Subtotal	$ 30,501,387	$ 4,909,462	$ 3,778,096	$ 3,555,018	$ 2,597,194	$2,085,195	$1,557,327	$1,277,518	$1,278,484	$1,338,217	$1,524,577	$2,427,961	$ 4,172,337
13														
14	**Total Core**	$ 88,559,687	$ 14,342,491	$11,025,379	$10,524,018	$ 7,646,634	$6,105,542	$4,434,547	$3,395,228	$3,392,863	$3,682,924	$4,411,918	$7,190,706	$ 12,407,437
15														
16	**Utility:**													
17	T-FUGC-1	$ 327,850	$ 28,990	$ 29,188	$ 28,475	$ 27,762	$ 27,152	$ 26,600	$ 26,101	$ 26,059	$ 26,067	$ 26,303	$ 26,909	$ 28,245
18														
19														
20	**NON-CORE:**													
21	DBU Non-Core:													
22	Firm Transportation	$ 2,386,159	$ 199,680	$ 199,154	$ 199,154	$ 199,154	$ 198,503	$ 198,503	$ 198,503	$ 198,503	$ 198,503	$ 198,689	$ 199,067	$ 198,749
23	Interruptible Transportation	$ 34,448	$ 6,005	$ 7,864	$ 5,553	$ 3,758	$ 1,231	$ 622	$ 550	$ 818	$ 772	$ 1,453	$ 1,496	$ 4,327
24	Subtotal	$ 2,420,607	$ 205,685	$ 207,017	$ 204,706	$ 202,911	$ 199,734	$ 199,125	$ 199,053	$ 199,321	$ 199,275	$ 200,141	$ 200,563	$ 203,076
25														
26	TBU Non-Core:													
27	Firm Transportation	$ 13,006,109	$ 1,123,699	$ 1,125,037	$ 1,101,246	$ 1,093,526	$1,065,383	$1,056,182	$1,038,222	$1,061,795	$1,070,753	$1,076,465	$1,094,698	$ 1,099,105
28	Interruptible Transportation	$ 2,442,349	$ 205,177	$ 178,383	$ 196,732	$ 194,635	$ 171,346	$ 195,732	$ 178,978	$ 201,794	$ 260,973	$ 219,193	$ 225,137	$ 214,271
29	Subtotal	$ 15,448,458	$ 1,328,875	$ 1,303,420	$ 1,297,977	$ 1,288,161	$1,236,729	$1,251,914	$1,217,200	$1,263,589	$1,331,725	$1,295,658	$1,319,835	$ 1,313,375
30														
31														
32	Storage T-FSG-1	$ 3,520,419	$ 323,138	$ 310,722	$ 284,843	$ 264,913	$ 283,035	$ 256,677	$ 281,636	$ 285,119	$ 308,090	$ 305,471	$ 307,368	$ 309,408
33														
34														
35	Off-System:													
36	Offsystem - Interruptible Transportation	$ 12,487	$ 1,377	$ 1,485	$ 1,195	$ 898	$ 337	$ 254	$ 195	$ 2,577	$ 2,847	$ 264	$ 289	$ 769
37														
38														
39	CMPL	$ 170,464	$ 14,075	$ 10,215	$ 9,460	$ 12,528	$ 15,842	$ 15,308	$ 15,128	$ 17,537	$ 19,057	$ 14,779	$ 15,635	$ 10,899
40														
41	Miscellaneous	$ 1,149,823	$ 164,454	$ 146,087	$ 133,855	$ 131,893	$ 89,390	$ 23,557	$ 94,204	$ 38,463	$ 53,935	$ 36,917	$ 118,051	$ 119,017
42														
43	Total	$111,609,795	$ 16,409,085	$13,033,514	$12,484,529	$ 9,575,700	$7,957,761	$6,207,982	$5,228,745	$5,225,526	$5,623,921	$6,291,450	$9,179,356	$ 14,392,227

NorthWestern Energy

NorthWestern Energy
Natural Gas Utility
12 Months Ended December 2015
Miscellaneous & Other Operating Revenues

Actual - Miscellaneous Revenues

Line No.		Total	January	February	March	April	May	June	July	August	September	October	November	December
1	**Miscellaneous**													
2	492100 Utility Oil Sales	562,430	32,637	46,891	30,580	87,559	40,295	23,105	93,654	36,766	52,941	36,405	56,216	25,382
3	492200 Utility Liquid Sal	32,075	12,564		7,185	(30,386)	6,035						36,677	
4	469410 NG Rents - Land	1,000				800							200	
5	469610 NG Other Rev-Misc	7,840	171	171	171	171	5,510	171	171	171	171	171	611	180
6	469620 NG Other Rev-Mat S	10,175		2,875	432		120	227	419	1,545	823	341	1,822	1,573
7	469649 NG Other Rev-DSM Lost Revenue	0												
8	[1]Total Without Low Income Discount	613,520	45,372	49,936	38,367	58,144	51,959	23,503	94,243	38,482	53,936	36,917	95,526	27,134
9														
10	469580 NG Other Low Inc D	536,303	119,082	96,150	95,488	73,749	37,431	54	(39)	(19)	(0)		22,525	91,883
11														
12	Total	1,149,823	164,454	146,087	133,855	131,893	89,390	23,557	94,204	38,463	53,935	36,917	118,051	119,017

[1]Reflect Miscellaneous without low income because revenues are reflected at gross amount. Low Income Discount is recovered through USB funding.

NorthWestern Energy

NorthWestern Energy
Natural Gas Utility
12 Months Ended December 2015

Normalized Consumption
MDDQ's & Dekatherms

Line No.	(A)	(B) Units	(C) TOTAL	(D) January	(E) February	(F) March	(G) April	(H) May	(I) June	(J) July	(K) August	(L) September	(M) October	(N) November	(O) December
1	**Core - DBU**														
2	RESIDENTIAL:														
3	Residential	Dkt	12,452,351	2,292,829	1,757,930	1,836,755	1,149,661	786,143	519,184	244,926	243,320	305,635	490,227	978,937	1,846,803
4	Employee	Dkt	28,206	4,984	3,979	4,175	2,715	2,000	1,439	522	553	655	1,135	2,109	3,940
5	Subtotal		12,480,557	2,297,813	1,761,909	1,840,931	1,152,376	788,143	520,623	245,448	243,873	306,290	491,362	981,045	1,850,743
6															
7	GENERAL SERVICE:														
8	Commercial	Dkt	6,512,452	1,191,340	903,026	920,186	583,369	406,517	279,240	182,123	174,229	191,606	254,113	493,148	933,555
9	Industrial Firm	Dkt	160,252	25,541	33,062	23,520	12,573	9,104	6,018	4,749	4,769	5,959	6,329	10,681	17,947
10	G & M	Dkt	60,404	11,972	6,099	8,517	5,526	3,965	2,626	876	1,677	1,717	2,687	5,850	8,893
11	Interdepart.	Dkt	58,825	10,470	7,798	8,163	5,937	3,819	3,159	1,472	1,458	1,668	2,297	4,550	8,033
12	Total - Gen. Ser.		6,791,933	1,239,323	949,986	960,386	607,405	423,405	291,043	189,221	182,133	200,950	265,425	514,228	968,427
13															
14	Core Market (Residential & General Service)		19,272,490	3,537,135	2,711,895	2,801,316	1,759,781	1,211,548	811,666	434,669	426,006	507,240	756,788	1,495,274	2,819,171
15															
16	Core - S&TBU: Utilities	Dkt	233,901	35,344	42,850	40,243	23,934	15,433	17,377	3,969	3,751	3,846	6,852	12,197	28,105
17	Transmission	MDDQ	33,012	2,751	2,751	2,751	2,751	2,751	2,751	2,751	2,751	2,751	2,751	2,751	2,751
18	Storage	MDDQ	18,156	1,513	1,513	1,513	1,513	1,513	1,513	1,513	1,513	1,513	1,513	1,513	1,513
19															
20	**Total Core Market**	Dkt	19,506,391	3,572,479	2,754,745	2,841,560	1,783,715	1,226,981	829,043	438,638	429,757	511,087	763,640	1,507,471	2,847,276
21															
22															
23	**Non-Core Market**														
24															
25	DBU Firm Transportation														
26	Firm Reservation	MDDQ	256,833	21,501	21,433	21,433	21,433	21,367	21,367	21,367	21,367	21,367	21,391	21,415	21,392
27	Interruptible Commodity	Dkt	135,360	23,597	30,899	21,818	14,766	4,838	2,443	2,162	3,214	3,035	5,708	5,878	17,002
28															
29	TBU Firm Transportation														
30	Firm Reservation	MDDQ	1,214,639	98,529	98,461	98,461	98,461	98,395	98,395	98,140	103,140	108,140	108,164	108,188	98,165
31	Firm Transportation	Dkt	17,506,478	2,006,995	2,034,017	1,713,150	1,609,036	1,243,340	1,119,243	915,826	1,092,424	1,227,707	1,288,514	1,522,591	1,733,635
32	Interrup Transportation	Dkt	6,035,341	494,791	419,793	475,233	476,987	428,075	492,083	450,033	506,627	656,324	548,092	562,941	524,362
33															
34	TBU Firm Storage														
35	Withdrawal Reservation	MDDQ	548,885	48,582	48,535	48,535	48,535	50,919	43,519	43,345	43,345	43,345	43,359	43,381	43,485
36	Injection Commodity	Dkt	3,200,683	4,003	3,459	3,516	11,012	358,760	362,637	676,614	420,305	719,961	312,462	198,601	129,353
37	Withdrawal Commodity	Dkt	3,245,988	567,503	1,200,183	805,799	400,267	7,320	658	506	32,977	545	527	750	228,953
38	Storage Capacity	Dkt	34,774,851	3,579,907	2,383,183	1,670,900	1,221,645	1,573,085	1,935,064	2,727,476	3,114,804	3,834,220	4,146,155	4,344,006	4,244,406
39															
40	Total Montana	Dkt	43,183,570	6,097,862	5,239,454	5,051,761	3,884,504	2,903,234	2,442,812	1,806,659	2,032,022	2,398,153	2,605,954	3,598,881	5,122,275

NorthWestern Energy

NorthWestern Energy
Natural Gas Utility
12 Months Ended December 2015
Distribution, Transmission & Storage

Normalized Test Period Revenues

Line No.	(A)	(B) Total	(C) January	(D) February	(E) March	(F) April	(G) May	(H) June	(I) July	(J) August	(K) September	(L) October	(M) November	(N) December
1	**CORE:**													
2	RESIDENTIAL:													
3	Residential	$ 60,820,434	$ 9,732,495	$ 7,743,753	$ 8,038,474	$ 5,483,792	$ 4,132,001	$ 3,138,849	$ 2,117,754	$ 2,111,301	$ 2,344,389	$ 3,034,281	$ 4,856,118	$ 8,087,227
4	Employee	$ 97,326	$ 15,505	$ 12,696	$ 13,234	$ 9,155	$ 7,155	$ 5,566	$ 2,999	$ 3,073	$ 3,359	$ 4,687	$ 7,403	$ 12,494
5	Subtotal	$ 60,917,760	$ 9,748,000	$ 7,756,449	$ 8,051,707	$ 5,492,946	$ 4,139,156	$ 3,144,415	$ 2,120,753	$ 2,114,374	$ 2,347,749	$ 3,038,968	$ 4,863,520	$ 8,099,721
6														
7	GENERAL SERVICE:													
8	Commercial	$ 30,643,035	$ 4,879,630	$ 3,844,458	$ 3,907,110	$ 2,697,686	$ 2,061,409	$ 1,603,400	$ 1,252,477	$ 1,235,309	$ 1,291,573	$ 1,519,437	$ 2,381,965	$ 3,968,581
9	Industrial Firm	$ 677,000	$ 100,370	$ 127,390	$ 93,020	$ 53,783	$ 41,220	$ 29,981	$ 25,401	$ 25,640	$ 29,673	$ 31,042	$ 46,680	$ 72,800
10	G & M	$ 259,026	$ 46,471	$ 25,291	$ 34,049	$ 23,298	$ 17,686	$ 12,805	$ 6,581	$ 9,604	$ 9,591	$ 13,366	$ 24,655	$ 35,630
11	Interdepart.	$ 238,718	$ 39,865	$ 30,261	$ 31,573	$ 23,571	$ 15,983	$ 13,609	$ 7,547	$ 7,592	$ 8,303	$ 10,565	$ 18,663	$ 31,184
12	Subtotal	$ 31,817,779	$ 5,066,336	$ 4,027,401	$ 4,065,751	$ 2,798,338	$ 2,136,297	$ 1,659,796	$ 1,292,005	$ 1,278,144	$ 1,339,141	$ 1,574,410	$ 2,471,963	$ 4,108,196
13														
14	**Total Core**	$ 92,735,539	$ 14,814,336	$ 11,783,850	$ 12,117,458	$ 8,291,284	$ 6,275,453	$ 4,804,211	$ 3,412,759	$ 3,392,518	$ 3,686,889	$ 4,613,379	$ 7,335,483	$ 12,207,917
15														
16	**Utility:**													
17	T-FUGC-1	$ 330,096	$ 28,967	$ 29,658	$ 29,418	$ 27,917	$ 27,134	$ 27,313	$ 26,079	$ 26,059	$ 26,068	$ 26,345	$ 26,837	$ 28,301
18														
19														
20	**NON-CORE:**													
21	DBU Non-Core:													
22	Firm Transportation	$ 2,408,640	$ 201,553	$ 201,027	$ 201,027	$ 201,027	$ 200,376	$ 200,376	$ 200,376	$ 200,376	$ 200,376	$ 200,562	$ 200,940	$ 200,622
23	Interruptible Transportation	$ 34,448	$ 6,005	$ 7,864	$ 5,553	$ 3,758	$ 1,231	$ 622	$ 550	$ 818	$ 772	$ 1,453	$ 1,496	$ 4,327
24	Subtotal	$ 2,443,089	$ 207,559	$ 208,891	$ 206,580	$ 204,785	$ 201,608	$ 200,998	$ 200,927	$ 201,194	$ 201,149	$ 202,015	$ 202,436	$ 204,949
25														
26	TBU Non-Core:													
27	Firm Transportation	$ 13,006,109	$ 1,123,699	$ 1,125,037	$ 1,101,246	$ 1,093,526	$ 1,065,383	$ 1,056,182	$ 1,038,222	$ 1,061,795	$ 1,070,753	$ 1,076,465	$ 1,094,698	$ 1,099,105
28	Interruptible Transportation	$ 2,442,349	$ 205,177	$ 178,383	$ 196,732	$ 194,635	$ 171,346	$ 195,732	$ 178,978	$ 201,794	$ 260,973	$ 219,193	$ 225,137	$ 214,271
29	Subtotal	$ 15,448,458	$ 1,328,875	$ 1,303,420	$ 1,297,977	$ 1,288,161	$ 1,236,729	$ 1,251,914	$ 1,217,200	$ 1,263,589	$ 1,331,725	$ 1,295,658	$ 1,319,835	$ 1,313,375
30														
31														
32	Storage T-FSG-1	$ 3,520,419	$ 323,138	$ 310,722	$ 284,843	$ 264,913	$ 283,035	$ 256,677	$ 281,636	$ 285,119	$ 308,090	$ 305,471	$ 307,368	$ 309,408
33														
34														
35	Off-System:													
36	Offsystem - Interruptible Transportation	$ 12,487	$ 1,377	$ 1,485	$ 1,195	$ 898	$ 337	$ 254	$ 195	$ 2,577	$ 2,847	$ 264	$ 289	$ 769
37														
38														
39	CMPL	$ 170,464	$ 14,075	$ 10,215	$ 9,460	$ 12,528	$ 15,842	$ 15,308	$ 15,128	$ 17,537	$ 19,057	$ 14,779	$ 15,635	$ 10,899
40														
41	Miscellaneous	$ 613,520	$ 45,372	$ 49,936	$ 38,367	$ 58,144	$ 51,959	$ 23,503	$ 94,243	$ 38,482	$ 53,936	$ 36,917	$ 95,526	$ 27,134
42														
43	Total	$ 115,274,072	$ 16,763,700	$ 13,698,177	$ 13,985,298	$ 10,148,630	$ 8,092,098	$ 6,580,178	$ 5,248,167	$ 5,227,075	$ 5,629,760	$ 6,494,826	$ 9,303,409	$ 14,102,754

NorthWestern Energy

NorthWestern Energy
Natural Gas Utility
12 Months Ended December 2015
Miscellaneous & Other Operating Revenues

Normalized - Test Year

Line No.		Total	January	February	March	April	May	June	July	August	September	October	November	December
1	**Miscellaneous**													
2	492100 Utility Oil Sales	562,430	32,637	46,891	30,580	87,559	40,295	23,105	93,654	36,766	52,941	36,405	56,216	25,382
3	492200 Utility Liquid Sal	32,075	12,564	0	7,185	(30,386)	6,035	0	0	0	0	0	36,677	0
4	469410 NG Rents - Land	1,000	0	0	0	800	0	0	0	0	0	0	200	0
5	469580 NG Other Low Inc D	0	0	0	0	0	0	0	0	0	0	0	0	0
6	469610 NG Other Rev-Misc	7,840	171	171	171	171	5,510	171	171	171	171	171	611	180
7	469620 NG Other Rev-Mat S	10,175	0	2,875	432	0	120	227	419	1,545	823	341	1,822	1,573
8														
9	Total	613,520	45,372	49,936	38,367	58,144	51,959	23,503	94,243	38,482	53,936	36,917	95,526	27,134

NorthWestern Energy

NorthWestern Energy
Natural Gas Utility
12 Months Ended December 2015
Distribution, Transmission & Storage

Proposed Uniform Design Revenues

Line No.	(A)	(B) Total	(C) January	(D) February	(E) March	(F) April	(G) May	(H) June	(I) July	(J) August	(K) September	(L) October	(M) November	(N) December
1	**CORE:**													
2	RESIDENTIAL:													
3	Residential	$ 63,800,994	$ 10,208,893	$ 8,122,925	$ 8,432,055	$ 5,752,480	$ 4,334,604	$ 3,292,898	$ 2,221,884	$ 2,215,115	$ 2,459,599	$ 3,183,220	$ 5,094,124	$ 8,483,197
4	Employee	$ 102,093	$ 16,263	$ 13,317	$ 13,881	$ 9,603	$ 7,506	$ 5,839	$ 3,146	$ 3,224	$ 3,524	$ 4,917	$ 7,765	$ 13,106
5	Subtotal	$ 63,903,086	$ 10,225,156	$ 8,136,243	$ 8,445,936	$ 5,762,083	$ 4,342,109	$ 3,298,737	$ 2,225,030	$ 2,218,339	$ 2,463,123	$ 3,188,137	$ 5,101,890	$ 8,496,303
6														
7	GENERAL SERVICE:													
8	Commercial	$ 32,138,686	$ 5,117,976	$ 4,032,196	$ 4,097,911	$ 2,829,362	$ 2,161,980	$ 1,681,581	$ 1,313,503	$ 1,295,510	$ 1,354,524	$ 1,593,526	$ 2,498,219	$ 4,162,401
9	Industrial Firm	$ 710,079	$ 105,275	$ 133,617	$ 97,566	$ 56,411	$ 43,233	$ 31,446	$ 26,641	$ 26,892	$ 31,122	$ 32,558	$ 48,961	$ 76,358
10	G & M	$ 271,689	$ 48,743	$ 26,528	$ 35,714	$ 24,437	$ 18,551	$ 13,431	$ 6,902	$ 10,074	$ 10,060	$ 14,019	$ 25,860	$ 37,372
11	Interdepart.	$ 250,386	$ 41,814	$ 31,741	$ 33,116	$ 24,723	$ 16,764	$ 14,274	$ 7,916	$ 7,963	$ 8,709	$ 11,082	$ 19,575	$ 32,709
12	Subtotal	$ 33,370,841	$ 5,313,808	$ 4,224,081	$ 4,264,306	$ 2,934,933	$ 2,240,527	$ 1,740,732	$ 1,354,962	$ 1,340,438	$ 1,404,415	$ 1,651,185	$ 2,592,615	$ 4,308,839
13														
14	**Total Core**	$ 97,273,927	$ 15,538,964	$ 12,360,324	$ 12,710,242	$ 8,697,016	$ 6,582,637	$ 5,039,469	$ 3,579,992	$ 3,558,777	$ 3,867,538	$ 4,839,322	$ 7,694,505	$ 12,805,142
15														
16	**Utility:**													
17	T-FUGC-1	$ 346,234	$ 30,383	$ 31,108	$ 30,856	$ 29,282	$ 28,461	$ 28,649	$ 27,354	$ 27,333	$ 27,342	$ 27,633	$ 28,149	$ 29,684
18														
19														
20	**NON-CORE:**													
21	DBU Non-Core:													
22	Firm Transportation	$ 2,526,414	$ 211,408	$ 210,856	$ 210,856	$ 210,856	$ 210,174	$ 210,174	$ 210,174	$ 210,174	$ 210,174	$ 210,369	$ 210,765	$ 210,432
23	Interruptible Transportation	$ 36,133	$ 6,299	$ 8,248	$ 5,824	$ 3,942	$ 1,291	$ 652	$ 577	$ 858	$ 810	$ 1,524	$ 1,569	$ 4,538
24	Subtotal	$ 2,562,547	$ 217,707	$ 219,105	$ 216,680	$ 214,798	$ 211,465	$ 210,826	$ 210,751	$ 211,032	$ 210,984	$ 211,893	$ 212,334	$ 214,970
25														
26	TBU Non-Core:													
27	Firm Transportation	$ 13,636,220	$ 1,178,634	$ 1,180,038	$ 1,155,083	$ 1,146,986	$ 1,117,468	$ 1,107,816	$ 1,088,979	$ 1,112,630	$ 1,121,589	$ 1,127,497	$ 1,146,662	$ 1,152,838
28	Interruptible Transportation	$ 2,561,752	$ 215,208	$ 187,104	$ 206,350	$ 204,150	$ 179,723	$ 205,301	$ 187,728	$ 211,659	$ 273,731	$ 229,909	$ 236,144	$ 224,746
29	Subtotal	$ 16,197,973	$ 1,393,842	$ 1,367,142	$ 1,361,433	$ 1,351,136	$ 1,297,190	$ 1,313,118	$ 1,276,706	$ 1,324,289	$ 1,395,320	$ 1,357,406	$ 1,382,806	$ 1,377,584
30														
31														
32	Storage T-FSG-1	$ 3,692,516	$ 338,935	$ 325,912	$ 298,768	$ 277,864	$ 296,871	$ 269,225	$ 295,404	$ 299,057	$ 323,151	$ 320,404	$ 322,393	$ 324,534
33														
34														
35	Off-System:													
36	Offsystem - interruptible Transportation	$ 12,487	$ 1,377	$ 1,485	$ 1,195	$ 898	$ 337	$ 254	$ 195	$ 2,577	$ 2,847	$ 264	$ 289	$ 769
37														
38														
39	CMPL	$ 170,464	$ 14,075	$ 10,215	$ 9,460	$ 12,528	$ 15,842	$ 15,308	$ 15,128	$ 17,537	$ 19,057	$ 14,779	$ 15,635	$ 10,899
40														
41	Miscellaneous	$ 613,520	$ 45,372	$ 49,936	$ 38,367	$ 58,144	$ 51,959	$ 23,503	$ 94,243	$ 38,482	$ 53,936	$ 36,917	$ 95,526	$ 27,134
42														
43	Total	$ 120,869,667	$ 17,580,655	$ 14,365,226	$ 14,667,002	$ 10,641,666	$ 8,484,763	$ 6,900,352	$ 5,499,775	$ 5,479,084	$ 5,900,175	$ 6,808,616	$ 9,751,637	$ 14,790,717

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**NorthWestern Energy**																	
2	**Natural Gas Utility Production Assets**																	
3	**12-Months Ended 2015**																	
4				Test Period Revenues								Revenues @ Uniform Design Rates						
5																		
6						Bear Paw		South Bear Paw				Interim		Bear Paw		South Bear Paw		
7				Battle Creek		(NFR)		Devon		Total		Battle Creek		(NFR)		Devon		Total
8		Fixed Rates		$ 0.1237		$ 0.1700		$ 0.7823				$ 0.1225		$ 0.1700		$ 0.7823		
9																		
10	**Core - DBU**	Market (Dkt)																
11	RESIDENTIAL:																	
12	Residential	12,429,997		$ 1,537,591		$ 2,113,100		$ 9,723,987		$ 13,374,677		$ 1,522,977		$ 2,113,100		$ 9,723,987		$ 13,360,063
13	Employee	28,206		2,617		3,596		16,549		22,763		2,592		3,596		16,549		22,738
14	Subtotal	12,458,204		$ 1,540,208		$ 2,116,696		$ 9,740,536		$ 13,397,440		$ 1,525,569		$ 2,116,696		$ 9,740,536		$ 13,382,801
15																		
16	GENERAL SERVICE:																	
17	Commercial	6,139,815		$ 759,495		$ 1,043,769		$ 4,803,177		$ 6,606,441		$ 752,277		$ 1,043,769		$ 4,803,177		$ 6,599,223
18	Industrial Firm	157,400		19,470		26,758		123,134		169,362		19,285		26,758		123,134		169,177
19	G & M	58,440		7,229		9,935		45,717		62,881		7,160		9,935		45,717		62,812
20	Interdepart.	58,825		7,277		10,000		46,018		63,295		7,207		10,000		46,018		63,226
21	Total - Gen. Ser.	6,414,479		$ 793,471		$ 1,090,461		$ 5,018,047		$ 6,901,979		$ 785,930		$ 1,090,461		$ 5,018,047		$ 6,894,438
22																		
23	**Total Core - DBU**																	
24																		
25	**Utilities**	233,901		$ 28,934		$ 39,763		$ 182,981		$ 251,677		$ 28,659		$ 39,763		$ 182,981		$ 251,402
26																		
27	**Total Rate Schedule**	19,106,584		$ 2,362,612		$ 3,246,920		$ 14,941,564		$ 20,551,096		$ 2,340,157		$ 3,246,920		$ 14,941,564		$ 20,528,641
28																		
29																		
30		Account																
31	Other Utility Revenues:																	
32	Offsystem Sales	457110		$ 33,612		$ 30,366				$ 63,978		$ 33,612		$ 30,366		0		$ 63,978
33	Gathering Revenues	459000				644,388				644,388		0		644,388		0		644,388
34	Gathering Revenues	459100						971,873		971,873		0		0		971,873		971,873
35																		
36																		
37	Miscellaneous:																	
38	Miscellaneous Revenues	469610		$ 115,677		$ 354,292		$ 401,529		$ 871,498		$ 115,677		$ 354,292		$ 401,529		$ 871,498
39	Oil & Liquid Sales	492200						135,129		135,129		0		0		135,129		135,129
40																		
41	**Total**			$ 2,511,901		$ 4,275,966		$ 16,450,094		$ 23,237,961		$ 2,489,446		$ 4,275,966		$ 16,450,094		$ 23,215,506
42																		
43	**Interim Proposed Revenue Change**			$ (22,455)		$ -		$ -		$ (22,455)								$ (22,455)
44																		
45	**Percentage Rate Change from Test Period**			-0.95%		0.00%		0.00%										
46																		
47	**Interim Proposed Rates**			$ 0.1225		$ 0.1700		$ 0.7823										
48																		
49																		
50	***Note: No proposed Interim rate change for Bear Paw (NFR) and South Bear Paw (Devon).***																	

NORTHWESTERN ENERGY - MONTANA GAS UTILITY INTERIM RATE BASE - 13 MONTH AVERAGE

NORTHWESTERN ENERGY COMPANY
EXHIBIT NO. CDL-1 PAGE OF

LINE	DESCRIPTION	(A) ACTUAL 13 MONTH AVERAGE RATE BASE 12/31/15	(B) TD&S NORMALIZING ADJUSTMENTS	(C) BATTLE CREEK	(D) BEAR PAW	(E) SOUTH BEAR PAW	(F) CMPL	(G) REGULATORY PLANT ADJ	(H) SUB-TOTAL	(I) TD&S DEFERRED TAXES	(J) OTHER	(K) WORKING CAPITAL	(L) TEST PERIOD 12/31/15 ADJUSTED	INTERIM ADJUSTMENTS	INTERIM - REMOVE BEAR PAW & SOUTH BEAR PAW	INTERIM 12/31/15 ADJUSTED	LINE
1	UTILITY PLANT IN SERVICE																1
2	Gas	617,924,475		12,395,450	16,080,164	61,756,259	370,973	-10,245,761	697,381,560				697,381,560		-77,835,423	619,545,137	2
3	Common	29,127,408		640,212	830,524	3,189,648		-210,536	33,577,257				33,577,257		-4,020,173	29,557,084	3
4	TOTAL UTILITY PLANT IN SERVICE	646,151,883		13,035,662	16,910,688	64,945,907	370,973	-10,456,297	730,958,817				730,958,817			649,102,221	4
5																	5
6	ACCUMULATED DEPRECIATION																6
7	Gas	261,810,409	121,916	3,189,723	4,185,519	7,469,547	287,258	0	277,084,372				277,084,372		-11,675,066	265,409,306	7
8	Common	11,471,503		252,141	327,093	1,256,207			13,306,944				13,306,944		-1,583,300	11,723,644	8
9	TOTAL ACCUMULATED DEPRECIATION	273,281,912	121,916	3,441,864	4,512,612	8,745,754	287,258	0	290,391,316				290,391,316			277,132,950	9
10																	10
11	TOTAL NET PLANT	372,869,970	-121,916	9,593,799	12,398,077	56,200,153	83,715	-10,456,297	440,567,501				440,567,501			371,969,272	11
12																	12
13																	13
14	GAS STORED UNDERGROUND	32,096,313							32,096,313				32,096,313		0	32,096,313	14
15	COST OF REFINANCING DEBT	4,044,903							4,044,903				4,044,903		0	4,044,903	15
16	GAS STORAGE SALES 2000 & 2001 (9-2039)	-10,199,816							-10,199,816				-10,199,816		0	-10,199,816	16
17	REGULATORY ASSET FAS 109	61,269,439							61,269,439				61,269,439		0	61,269,439	17
18	MPSC/MCC TAXES	130,100		-582					129,518		163,570		293,088		0	293,088	18
19																	19
20																	20
21	LESS: CUSTOMER CONTRIBUTED CAPITAL																21
22	Accumulated Deferred Income Taxes																22
23	See Page 2 for Details	72,628,130		738,103	-41,916	2,846,250			76,170,567	-1,401,486	0		74,769,081	45,467	-2,804,334	72,010,214	23
24	Personal Injury & Property Damage	3,065,278							3,065,278				3,065,278		0	3,065,278	24
25	Customer Advances for Construction	6,813,187							6,813,187				6,813,187		0	6,813,187	25
26	TOTAL CUSTOMER CONTRIBUTED CAPITAL	82,506,595	0	738,103	-41,916	2,846,250	0	0	86,049,032	-1,401,486	0		84,647,546			81,888,679	26
27																	27
28	PLUS: WORKING CAPITAL																28
29	Gross Cash Requirements	-13,582,217							-13,582,217			-4,835,508	-18,417,725		2,352,029	-16,065,696	29
30	Materials and Supplies	7,085,112							7,085,112				7,085,112		0	7,085,112	30
31	TOTAL WORKING CAPITAL	-6,497,105							-6,497,105			-4,835,508	-11,332,613			-8,980,584	31
32																	32
33	TOTAL GAS UTILITY RATE BASE	371,207,209	-121,916	8,855,114	12,439,993	53,353,904	83,715	-10,456,297	435,361,722	1,401,486	163,570	-4,835,508	432,091,269			368,603,936	33

1	Accumulated Deferred Income Taxes																1
2	Regulatory Liability - MPSC Taxes	101,752		-245	-379	-708			100,421				100,421		1,087	101,508	2
3	Accelerated Depreciation	35,511,306		665,268	654,837	2,083,596			38,915,006	1,501,507			40,416,513	45,244	-2,738,432	37,723,324	3
4	Customer Advances for Construction	-2,857,343		-1,733	-2,685	-5,020			-2,866,781				-2,866,781		7,705	-2,859,076	4
5	Net Operating Loss	-4,725,381		99,162	-855,957	838,922			-4,443,254	-2,902,993			-7,346,247	223	-182,965	-7,528,989	5
6	Deferred Revenue	-5,436,426		-19,345	-29,977	-56,041			-5,541,789				-5,541,789		86,018	-5,455,771	6
7	Accrued Incentive Compensation	-691,258		-1,070	-1,658	-3,099			-697,085				-697,085		4,757	-692,328	7
8	Injuries & Damages	-972,246		1,758	2,724	5,093			-962,671				-962,671		-7,817	-970,488	8
9	Cost of Refinancing Debt	-197,470		-521	-808	-1,510			-200,309				-200,309		2,318	-197,991	9
10	Property Taxes	5,216		0	0	0			5,216				5,216		0	5,216	10
11	FAS 106 & FAS 112 Post Retirement Benefits	-9,088,186		-4,742	-7,348	-13,737			-9,114,013				-9,114,013		21,085	-9,092,928	11
12	Environmental Reserve	-491,273		-430	-666	-1,246			-493,615				-493,615		1,912	-491,703	12
13	Regulatory Asset FAS 109	61,269,439		0	0	0			61,269,439				61,269,439		0	61,269,439	13
14											0						14
15	Total Deferred Income Taxes	72,628,130	0	738,103	-41,916	2,846,250	0	0	76,170,567	-1,401,486	0	0	74,769,081	45,467	-2,804,334	72,010,214	15

NORTHWESTERN ENERGY - MONTANA TRANSMISSION & DISTRIBUTION INTERIM RATE BASE - 13 MONTH AVERAGE

NORTHWESTERN ENERGY COMPANY
EXHIBIT NO. CDL-1 PAGE OF

LINE	DESCRIPTION	(A) ACTUAL 13 MONTH AVERAGE RATE BASE 12/31/15	(B) REGULATORY PLANT ADJ	(C) SUB-TOTAL	(D) TD&S NORMALIZING ADJUSTMENTS	(I) DEFERRED TAXES	(J) OTHER	(K) WORKING CAPITAL	(L) TEST PERIOD 12/31/15 ADJUSTED	INTERIM ADJUSTMENTS	INTERIM 12/31/15 ADJUSTED	LINE
1	UTILITY PLANT IN SERVICE											1
2	Gas	617,024,475	-10,245,761	606,778,714					606,778,714		606,778,714	2
3	Common	29,127,408	-210,536	28,916,872					28,916,872		28,916,872	3
4	TOTAL UTILITY PLANT IN SERVICE	646,151,883	-10,456,297	635,695,586					635,695,586		635,695,586	4
5												5
6	ACCUMULATED DEPRECIATION											6
7	Gas	261,810,409	0	261,810,409	121,916				261,932,325		261,932,325	7
8	Common	11,471,503		11,471,503					11,471,503		11,471,503	8
9	TOTAL ACCUMULATED DEPRECIATION	273,281,912	0	273,281,912	121,916				273,403,828		273,403,828	9
10												10
11	TOTAL NET PLANT	372,869,970	-10,456,297	362,413,674	-121,916				362,291,758		362,291,758	11
12												12
13												13
14	GAS STORED UNDERGROUND	32,096,313		32,096,313					32,096,313		32,096,313	14
15	COST OF REFINANCING DEBT	4,044,903		4,044,903					4,044,903		4,044,903	15
16	GAS STORAGE SALES 2000 & 2001 (9-2039)	-10,199,816		-10,199,816					-10,199,816		-10,199,816	16
17	REGULATORY ASSET FAS 109	61,269,439		61,269,439					61,269,439		61,269,439	17
18	MPSC/MCC TAXES	130,100		130,100			163,570		293,670		293,670	18
19												19
20												20
21	LESS: CUSTOMER CONTRIBUTED CAPITAL											21
22	Accumulated Deferred Income Taxes											22
23	See Page 2 for Details	72,628,130		72,628,130		-1,401,486	0		71,226,644	45,445	71,272,089	23
24	Personal Injury & Property Damage	3,065,278		3,065,278					3,065,278		3,065,278	24
25	Customer Advances for Construction	6,813,187		6,813,187					6,813,187		6,813,187	25
26	TOTAL CUSTOMER CONTRIBUTED CAPITAL	82,506,595	0	82,506,595	0	-1,401,486	0		81,105,109		81,150,554	26
27												27
28	PLUS: WORKING CAPITAL											28
29	Gross Cash Requirements	-13,582,217		-13,582,217				-2,241,586	-15,823,803		-15,823,803	29
30	Materials and Supplies	7,085,112		7,085,112					7,085,112		7,085,112	30
31	TOTAL WORKING CAPITAL	-6,497,105		-6,497,105				-2,241,586	-8,738,691		-8,738,691	31
32												32
33	TOTAL GAS UTILITY RATE BASE	371,207,209	-10,456,297	360,750,913	-121,916	1,401,486	163,570	-2,241,586	359,952,466		359,907,021	33

1	Accumulated Deferred Income Taxes											1
2	Regulatory Liability - MPSC Taxes	101,752		101,752					101,752		101,752	2
3	Accelerated Depreciation	35,511,306		35,511,306		1,501,507			37,012,813	45,222	37,058,035	3
4	Customer Advances for Construction	-2,657,343		-2,657,343					-2,657,343		-2,657,343	4
5	Net Operating Loss	-4,725,381		-4,725,381		-2,902,993			-7,628,374	223	-7,628,151	5
6	Deferred Revenue	-5,436,426		-5,436,426					-5,436,426		-5,436,426	6
7	Accrued Incentive Compensation	-691,258		-691,258					-691,258		-691,258	7
8	Injuries & Damages	-972,246		-972,246					-972,246		-972,246	8
9	Cost of Refinancing Debt	-197,470		-197,470					-197,470		-197,470	9
10	Property Taxes	5,216		5,216					5,216		5,216	10
11	FAS 106 & FAS 112 Post Retirements Benefits	-9,088,186		-9,088,186					-9,088,186		-9,088,186	11
12	Environmental Reserve	-491,273		-491,273					-491,273		-491,273	12
13	Regulatory Asset FAS 109	61,269,439		61,269,439					61,269,439		61,269,439	13
14							0					14
15	Total Deferred Income Taxes	72,628,130	0	72,628,130		-1,401,486	0	0	71,226,644	45,445	71,272,089	15

NORTHWESTERN ENERGY - BATTLE CREEK INTERIM RATE BASE - 13 MONTH AVERAGE NORTHWESTERN ENERGY COMPANY
EXHIBIT NO. CDL-1 PAGE OF

LINE	DESCRIPTION	(B) BATTLE CREEK	(G) REGULATORY PLANT ADJ	NORMALIZING ADJUSTMENT	(I) DEFERRED TAXES	(J) OTHER	(K) WORKING CAPITAL	(L) TEST PERIOD 12/31/15 ADJUSTED	INTERIM ADJUSTMENTS	INTERIM 12/31/15 ADJUSTED	LINE
1	UTILITY PLANT IN SERVICE										1
2	Gas	12,395,450						12,395,450		12,395,450	2
3	Common	640,212						640,212		640,212	3
4	TOTAL UTILITY PLANT IN SERVICE	13,035,662	0					13,035,662		13,035,662	4
5											5
6	ACCUMULATED DEPRECIATION										6
7	Gas	3,250,948	0	-61,225				3,189,723		3,189,723	7
8	Common	252,141						252,141		252,141	8
9	TOTAL ACCUMULATED DEPRECIATION	3,503,089	0	-61,225				3,441,864		3,441,864	9
10											10
11	TOTAL NET PLANT	9,532,574	0	61,225				9,593,799		9,593,799	11
12											12
13											13
14	GAS STORED UNDERGROUND							0		0	14
15	COST OF REFINANCING DEBT							0		0	15
16	GAS STORAGE SALES 2000 & 2001 (9-2039)							0		0	16
17	REGULATORY ASSET FAS 109							0		0	17
18	MPSC/MCC TAXES					-582		-582		-582	18
19											19
20											20
21	LESS: CUSTOMER CONTRIBUTED CAPITAL										21
22	Accumulated Deferred Income Taxes										22
23	See Page 2 for Details	953,444			-215,341	0		738,103	22	738,125	23
24	Personal Injury & Property Damage							0		0	24
25	Customer Advances for Construction							0		0	25
26	TOTAL CUSTOMER CONTRIBUTED CAPITAL	953,444	0		-215,341	0		738,103		738,125	26
27											27
28	PLUS: WORKING CAPITAL										28
29	Gross Cash Requirements						-241,893	-241,893		-241,893	29
30	Materials and Supplies							0		0	30
31	TOTAL WORKING CAPITAL						-241,893	-241,893		-241,893	31
32											32
33	TOTAL GAS UTILITY RATE BASE	8,579,130	0	61,225	215,341	-582	-241,893	8,613,221		8,613,199	33

1	Accumulated Deferred Income Taxes										1
2	Regulatory Liability - MPSC Taxes				-245			-245		-245	2
3	Accelerated Depreciation	360,878			304,390			665,268	22	665,290	3
4	Customer Advances for Construction				-1,733			-1,733		-1,733	4
5	Net Operating Loss	592,566			-493,404			99,162		99,162	5
6	Deferred Revenue				-19,345			-19,345		-19,345	6
7	Accrued Incentive Compensation				-1,070			-1,070		-1,070	7
8	Injuries & Damages				1,758			1,758		1,758	8
9	Cost of Refinancing Debt				-521			-521		-521	9
10	Property Taxes							0		0	10
11	FAS 106 & FAS 112 Post Retirements Benefits				-4,742			-4,742		-4,742	11
12	Environmental Reserve				-430			-430		-430	12
13	Regulatory Asset FAS 109							0		0	13
14						0					14
15	Total Deferred Income Taxes	953,444	0		-215,341	0	0	738,103	22	738,125	15

NORTHWESTERN ENERGY - CANADIAN MONTANA PIPELINE INTERIM RATE BASE - 13 MC NORTHWESTERN ENERGY COMPANY
EXHIBIT NO. CDL-1 PAGE OF

LINE	DESCRIPTION	(B) CMPL	(G) REGULATORY PLANT ADJ	NORMALIZING ADJUSTMENT	(I) DEFERRED TAXES	(J) OTHER	(K) WORKING CAPITAL	(L) TEST PERIOD 12/31/15 ADJUSTED	INTERIM ADJUSTMENTS	INTERIM 12/31/15 ADJUSTED	LINE
1	UTILITY PLANT IN SERVICE										1
2	Gas	370,973						370,973		370,973	2
3	Common							0		0	3
4	TOTAL UTILITY PLANT IN SERVICE	370,973	0					370,973		370,973	4
5											5
6	ACCUMULATED DEPRECIATION										6
7	Gas	279,968	0	7,290				287,258		287,258	7
8	Common							0		0	8
9	TOTAL ACCUMULATED DEPRECIATION	279,968	0	7,290				287,258		287,258	9
10											10
11	TOTAL NET PLANT	91,005	0	-7,290				83,715		83,715	11
12											12
13											13
14	GAS STORED UNDERGROUND							0		0	14
15	COST OF REFINANCING DEBT							0		0	15
16	GAS STORAGE SALES 2000 & 2001 (9-2039)							0		0	16
17	REGULATORY ASSET FAS 109							0		0	17
18	MPSC/MCC TAXES							0		0	18
19											19
20											20
21	LESS: CUSTOMER CONTRIBUTED CAPITAL										21
22	Accumulated Deferred Income Taxes										22
23	See Page 2 for Details				0	0		0		0	23
24	Personal Injury & Property Damage							0		0	24
25	Customer Advances for Construction							0		0	25
26	TOTAL CUSTOMER CONTRIBUTED CAPITAL	0	0		0	0		0		0	26
27											27
28	PLUS: WORKING CAPITAL										28
29	Gross Cash Requirements						0	0		0	29
30	Materials and Supplies							0		0	30
31	TOTAL WORKING CAPITAL						0	0		0	31
32											32
33	TOTAL GAS UTILITY RATE BASE	91,005	0	-7,290	0	0	0	83,715		83,715	33

1	Accumulated Deferred Income Taxes										1
2	Regulatory Liability - MPSC Taxes							0		0	2
3	Accelerated Depreciation							0		0	3
4	Customer Advances for Construction							0		0	4
5	Net Operating Loss							0		0	5
6	Deferred Revenue							0		0	6
7	Accrued Incentive Compensation							0		0	7
8	Injuries & Damages							0		0	8
9	Cost of Refinancing Debt							0		0	9
10	Property Taxes							0		0	10
11	FAS 106 & FAS 112 Post Retirements Benefits							0		0	11
12	Environmental Reserve							0		0	12
13	Regulatory Asset FAS 109							0		0	13
14						0					14
15	Total Deferred Income Taxes	0	0		0	0	0	0	0	0	15

NORTHWESTERN ENERGY - MONTANA GAS UTILITY
INTERIM CALCULATION OF CASH WORKING CAPITAL
MONTANA TRANSMISSION, DISTRIBUTION & STORAGE

TEST PERIOD 2015

LINE No.			12 MONTH ENDED EXPENSES	NET LAG DAYS *1	CASH WORKING CAPITAL
1	GAS DELIVERY O & M COSTS		47,649,005		
2	OTHER TAXES		33,975,479		
3	STATE INCOME TAXES		0		
4	FEDERAL INCOME TAXES		1		
5	SUB-TOTAL		81,624,485	-65.21	-14,582,829
6	RATE BASE w/o CWC	375,769,169			
7	WEIGHTED COST OF DEBT *2	2.49%			
8	INTEREST EXPENSE IN RETURN		9,356,652	-48.41	-1,240,974
9	TOTAL CASH WORKING REQUIREMENT				-15,823,803
10	WORKING CASH - 2015 ACTUAL				-13,582,217
11	CASH WORKING CAPITAL ADJUSTMENT				-2,241,586

1* NET LAG DAYS FROM MAC 2015 LEAD/LAG UPDATE

2* WEIGHTED COST FROM PROPOSED CAPITAL STRUCTURE

NORTHWESTERN ENERGY - MONTANA GAS UTILITY
INTERIM CALCULATION OF CASH WORKING CAPITAL
BATTLE CREEK

TEST PERIOD 2015

LINE No.			12 MONTH ENDED EXPENSES	NET LAG DAYS *1	CASH WORKING CAPITAL
1	GAS DELIVERY O & M COSTS		1,126,765		
2	OTHER TAXES		67,971		
3	STATE INCOME TAXES		0		
4	FEDERAL INCOME TAXES		0		
5	SUB-TOTAL		1,194,736	-65.21	-213,449
6	RATE BASE w/o CWC	8,613,051			
7	WEIGHTED COST OF DEBT *2	2.49%			
8	INTEREST EXPENSE IN RETURN		214,465	-48.41	-28,445
9	TOTAL CASH WORKING REQUIREMENT				-241,893
10	WORKING CASH - 2015 ACTUAL (was not split)				0
11	CASH WORKING CAPITAL ADJUSTMENT				-241,893

1* NET LAG DAYS FROM MAC 2015 LEAD/LAG UPDATE

2* WEIGHTED COST FROM PROPOSED CAPITAL STRUCTURE

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF ROBERT C. ROWE

ON BEHALF OF NORTHWESTERN ENERGY

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Witness Information

Q. Please state your name and business address.

A. My name is Robert (Bob) C. Rowe. My business address is 11 East Park, Butte, MT 59701.

Q. By whom are you employed and in what capacity?

A. I am employed by NorthWestern Energy ("NorthWestern") as the President and Chief Executive Officer. I have held this position since August 2008. I also serve as the only non-independent Director on NorthWestern Corporation's Board of Directors.

Q. Please describe your professional roles, education, and relevant employment history.

A. I was privileged to join NorthWestern in 2008. In addition, I am a member of the Edison Electric Institute ("EEI") Board of Directors and Executive Committee. I am co-chair of the Institute for Energy Innovation (part of the Edison Foundation, a project of EEI). I am on the American Gas Association Board of Directors. I am past Chairman of the Western Energy Institute and a senior fellow with the University of Florida Public Utility Research Center.

From 2005 through 2008, I was senior partner in Balhoff, Rowe & Williams, a specialized national professional services firm providing financial and policy advice in the telecommunications and utility industries. Prior to that, I was a

commissioner with the Montana Public Service Commission ("MPSC" or "Commission") for 12 years from 1993 through 2004. During that period, I served at various times as Chairman of the Commission, Chairman of the National Association of Regulatory Utility Commissioners ("NARUC") Telecommunications Committee, President of NARUC, Chairman of the Regional Oversight Committee for US West, and in other capacities. I was a member of the Federal State Joint Board on Universal Service, and also initially proposed and served on the Federal-State Joint Conference on Advanced Services. I was active nationally, regionally, and in Montana on telecommunications and energy matters. I testified before the United States Senate Energy Committee, the House and Senate Commerce Committees, in other legislative hearings, and before the Federal Communications Commission. I have also participated as a trainer in scores of university-based and other professional training events. Over my career I have been a member of various other university-related boards, including at Columbia University. I received a Bachelor of Arts degree in History and Political Science from Lewis and Clark College in Portland, Oregon, a Juris Doctorate from the University of Oregon, and I completed the Kennedy School Senior Executives Program.

Purpose of Filing and Testimony

Q. What is the purpose of this filing?

A. We have worked to invest responsibly in the safety and adequacy of our natural gas system, while also keeping customers' average bills below the national

average, and on a declining curve over recent years. Now, as a result of the increased costs of operating, maintaining, and administering natural gas utility service and significant capital investments in the natural gas system since our last filing with the Commission in 2012, overall costs have increased to a level that requires NorthWestern to request an adjustment to its natural gas distribution, transportation, and storage rates. This is necessary to cover our overall cost of service and to enable the continued provision of safe and reliable natural gas service at just and reasonable rates. This filing also includes a request to include our two most recent natural gas production acquisitions in rate base on a permanent basis.

In addition, the Commission ordered us to make a comprehensive filing regarding regulatory approaches for our natural gas production assets and permitted us to include the required information in a general natural gas rate case. The Commission stated:

> *Specifically, the Commission believes it may be appropriate to recover the costs of these properties on an annual basis according to their actual or forecast costs, at least for the first years of the utility's ownership. Accordingly, the Commission requires a comprehensive filing to be made by NorthWestern within the next 12 months of the service date of this Order that must include all necessary data to calculate rates under a range of regulatory approaches to the cost-recovery of the gas production fields that NorthWestern owns and operates. That filing must include sufficient cost and ancillary information to calculate fixed cost rates for the Battle Creek, NFR, and Devon gas production fields under a range of regulatory approaches. If NorthWestern files a comprehensive rate case for its natural gas utility within that period, the assets and requisite information must be included in the comprehensive filing.*

Docket Nos. D2013.5.34 and D2014.5.47, Order No. 7282d, ¶ 32.

1 **Q. What is the purpose of your testimony?**

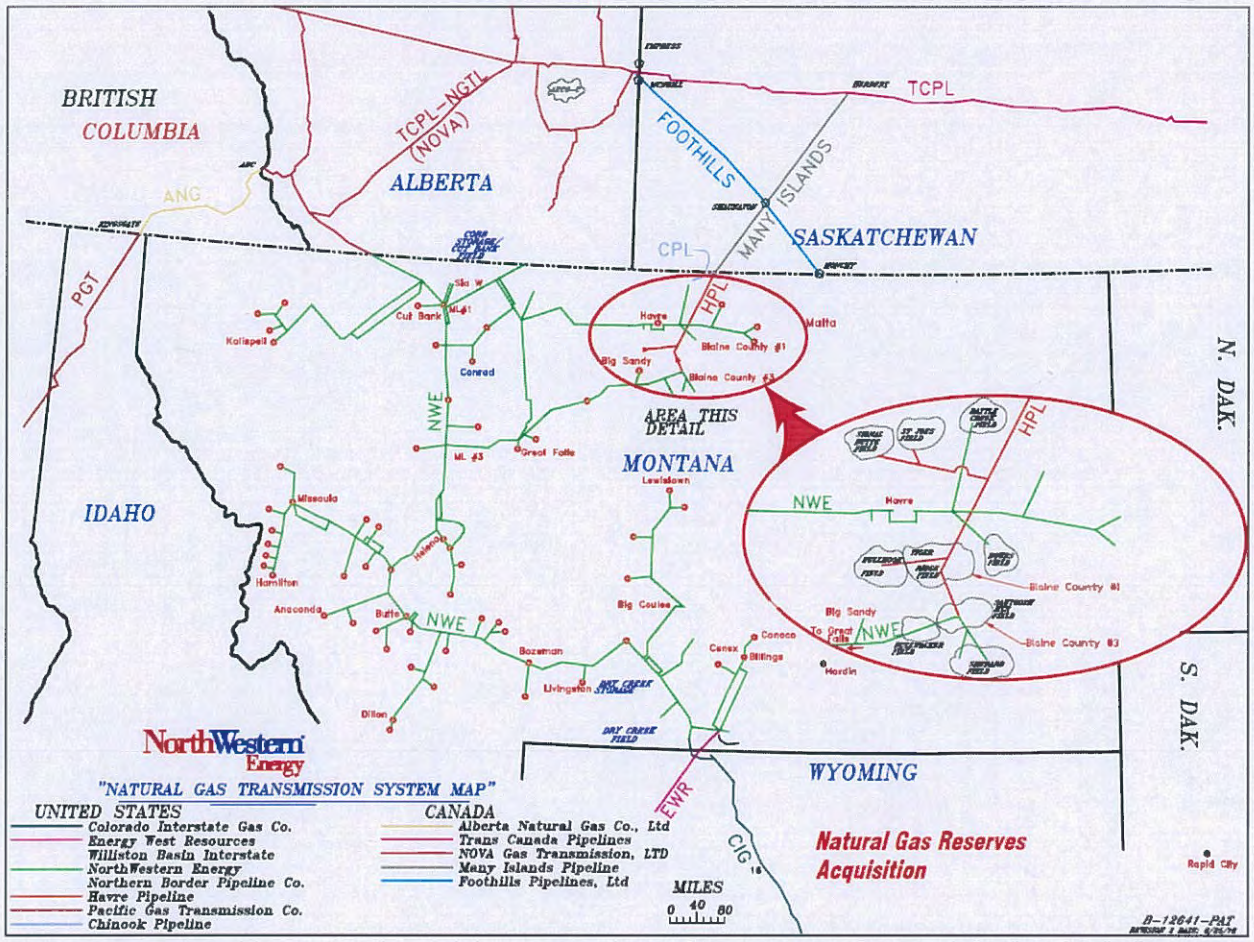
2 **A.** This case is about investing in providing our customers safe and reliable natural
3 gas service. My testimony introduces several subjects. First, I provide an
4 overview of NorthWestern's natural gas utility service operations, including a brief
5 description of our distribution, transmission, and supply production initiatives.
6 Second, I present an overview of this filing including a summary of the requested
7 revenue requirement and the key underlying factors. I also discuss the
8 relationship between that revenue requirement and NorthWestern's financial
9 health, as a utility must be financially strong in order to provide safe and reliable
10 gas service to customers. Finally, I introduce the other NorthWestern witnesses
11 supporting this request.
12
13 A contested case is one of several ways through which the Commission receives
14 information about a regulated company. I believe that through the course of this
15 case, along with our recurring informational presentations, the Commission will
16 conclude that NorthWestern focuses on meeting our commitments to the
17 customers and communities we serve. The Commission's decision in this case
18 will determine whether and to what extent NorthWestern can continue to plan
19 and invest in this critical natural gas infrastructure and service.
20
21 **<u>NorthWestern's Natural Gas Utility Overview</u>**

22 **Q. Please provide a brief general description of the operations of**
23 **NorthWestern's natural gas utility in Montana.**

A. NorthWestern operates and maintains a natural gas distribution, transportation, and storage system, which delivers natural gas to approximately 189,400 customers located in 117 Montana communities. We also serve several smaller distribution companies that provide service to about 31,000 customers. Our natural gas distribution system consists of approximately 5,000 miles of underground distribution pipeline. NorthWestern provides storage and transportation services for natural gas in Montana from production receipt points and storage facilities to distribution points and interconnection with other nonaffiliated transportation systems. NorthWestern's natural gas transmission system consists of more than 2,000 miles of pipeline and serves more than 130 city gate stations. In addition, we own and operate a pipeline that crosses into Canada through our wholly owned subsidiary, Canadian-Montana Pipeline Company. NorthWestern owns and operates three working natural gas storage fields in Montana. NorthWestern owns and operates three natural gas production facilities along with the associated gathering systems.

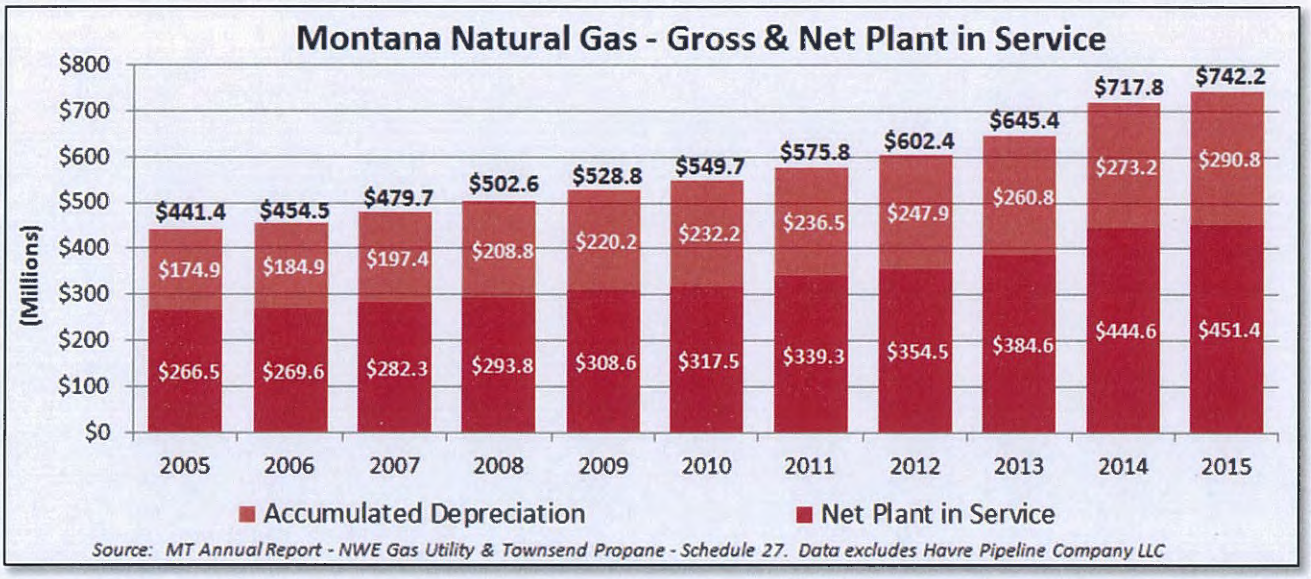
To assist the Commission in understanding the scope of NorthWestern's natural gas operations, I have included below a map of NorthWestern's Montana Natural Gas Transmission System. This map illustrates the system's location and size, and the transmission and distribution network dispersed throughout the various towns and communities (our system is in green).

Montana Natural Gas Transmission System Map

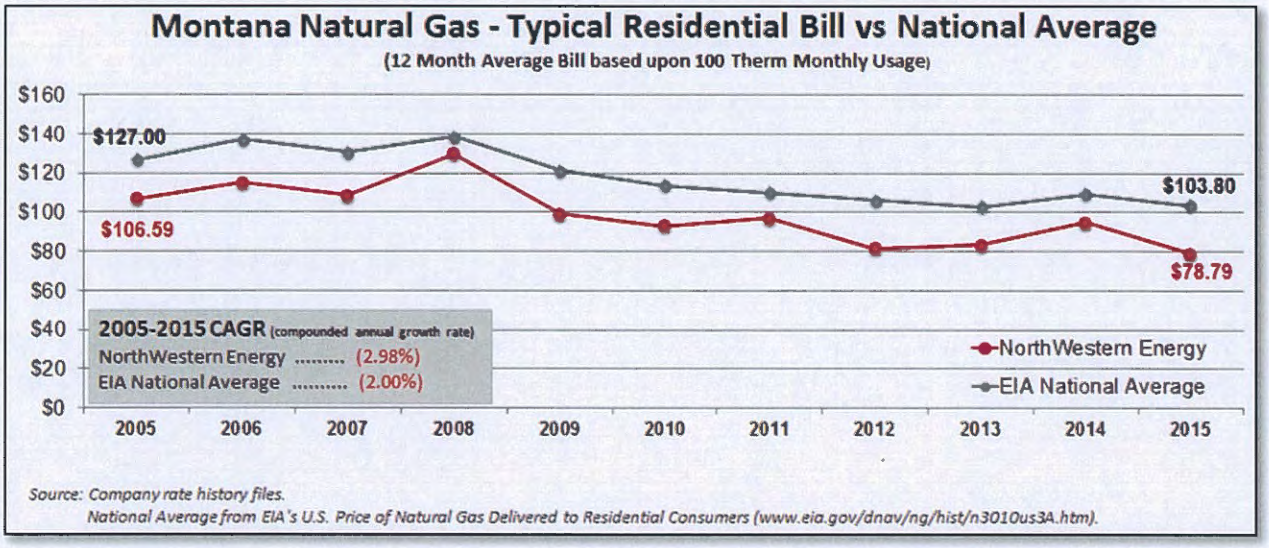


1 **Q. What is NorthWestern's approach to serving its Montana natural gas**
2 **customers?**

3 **A.** NorthWestern intensely focuses on providing safe, adequate, and reliable utility
4 service at fair prices now and into the future. This includes striving for
5 reasonable long-term price stability and prioritizing our major investments to
6 provide our customers long-term value.



As shown in the chart above, since 2005 NorthWestern's gross investment in Montana natural gas infrastructure has grown from just over $441 million to $742 million; during the same period, as shown in the chart below, a NorthWestern residential customer's typical bill has decreased from $106.59 to $78.79[1] and has consistently been below the national average.



[1] Calculated based on a 12-month average.

For our Montana natural gas operation, our commitment includes long-term asset management of our production, transmission (including storage and gathering), and distribution facilities; natural gas customer service operations; and ensuring that our employees have the right training, equipment, and support to serve our customers, while ensuring their own health and safety.

Q. Please provide an overview of NorthWestern's natural gas distribution and transmission initiatives.

A. NorthWestern is undertaking a number of active initiatives affecting the provision of natural gas utility service, which can be classified as distribution, transmission, or supply.

For distribution, we are proceeding with the Distribution System Infrastructure Project ("DSIP"), Distribution Infrastructure Management Program ("DIMP"), and gas leak minimization. DSIP's goals are to maintain and enhance future reliability by replacing aging infrastructure and building more capacity into the system through targeted proactive equipment replacements. Curtis T. Pohl ("Curt"), in his Prefiled Direct Testimony describes DSIP in depth. In 2010, the federal Pipeline and Hazardous Materials Safety Administration ("PHMSA") mandated operators of natural gas distribution lines to develop and implement integrity management programs. DIMP is NorthWestern's compliance with this requirement. This federally mandated program has increased NorthWestern's costs. Curt provides more information about our DIMP. We have a systematic

and active effort to minimize gas leaks, which improves safety and reliability. Curt also provides more information about this effort, including graphs that demonstrate our progress.

Concerning gas transmission, NorthWestern's initiatives include Pipeline Integrity Management ("PIM"), Integrity Verification Process ("IVP"), and investment in Reliability-Proactive and Major Projects categories. PIM is another PHMSA-mandated program. The Prefiled Direct Testimony of Michael R. Cashell ("Mike") contains details about NorthWestern's PIM, including the capital expenditures and expenses that compliance has required. Since our last natural gas rate case, NorthWestern has invested $18.1 million in the Reliability-Proactive and Major Projects categories. This represents nearly 54% of NorthWestern's total investment in our gas transmission and storage system during that period. Mike describes the details of our investment in these areas. IVP is a program included in current PHMSA regulations. IVP requires NorthWestern to assemble reliable, verifiable, traceable, and complete records to determine safe operating pressure for older pipelines. Mike details the IVP process and requirements.

I have often said that we "enthusiastically embrace" compliance programs that produce positive value, especially concerning safety. As described by Curt and Mike, DIMP, PIM, and IVP are consistent with this philosophy and with our internal focus as a company. However, these federally mandated programs impose significant costs. No one can reasonably question the necessity and

1 prudency of complying with PHMSA's regulations. We need to ensure timely
2 recovery of both the capital investment and increased expenses associated with
3 important and mandatory programs such as these.
4
5 **Q Is NorthWestern also identifying long-term sources of owned natural gas**
6 **supply as a natural gas production initiative?**
7 **A.** Yes. NorthWestern has been actively engaged in seeking to acquire natural gas
8 production assets. Strategic gas production assets can provide long-term pricing
9 stability for our customers. These activities were undertaken in implementation
10 of House Bill 294 passed by the 2009 Montana Legislature, which is now
11 Montana law. This law is the foundation of our strategy to provide our Montana
12 natural gas customers with a regulated source of proven supply that should help
13 provide price stability to the gas portfolio for many years.
14
15 Over the past several years, NorthWestern has established a process to identify,
16 analyze, and pursue opportunities to acquire natural gas reserves and
17 production. In the summer of 2010, NorthWestern acquired a majority interest in
18 the Battle Creek natural gas field located in north central Montana. The
19 Commission approved inclusion of Battle Creek in rate base and recovery of its
20 costs in Docket No. D2012.3.25. Subsequently, NorthWestern acquired the Bear
21 Paw (NFR) and the South Bear Paw (Devon) properties. NorthWestern has
22 increased its ownership interest in these properties by acquiring the interests of
23 minority owners, including an additional interest in Bear Paw (NFR) from a

subsidiary of Black Hills Corporation. NorthWestern has recovered costs for the Bear Paw (NFR) and Bear Paw South (Devon) properties on an interim basis since their respective acquisitions. In this docket, NorthWestern is requesting that the properties be approved for inclusion as rate-based assets, proposing a true-up of their cost recovery prior to this filing, and recommending a permanent rate treatment from among the three described by the Commission in Order No. 7282d. While NorthWestern continues to seek opportunities to acquire natural gas production assets, it can do so only if the acquisitions make financial sense for NorthWestern as well as for our customers.

Filing Overview

Q. Please provide an overview of this filing.

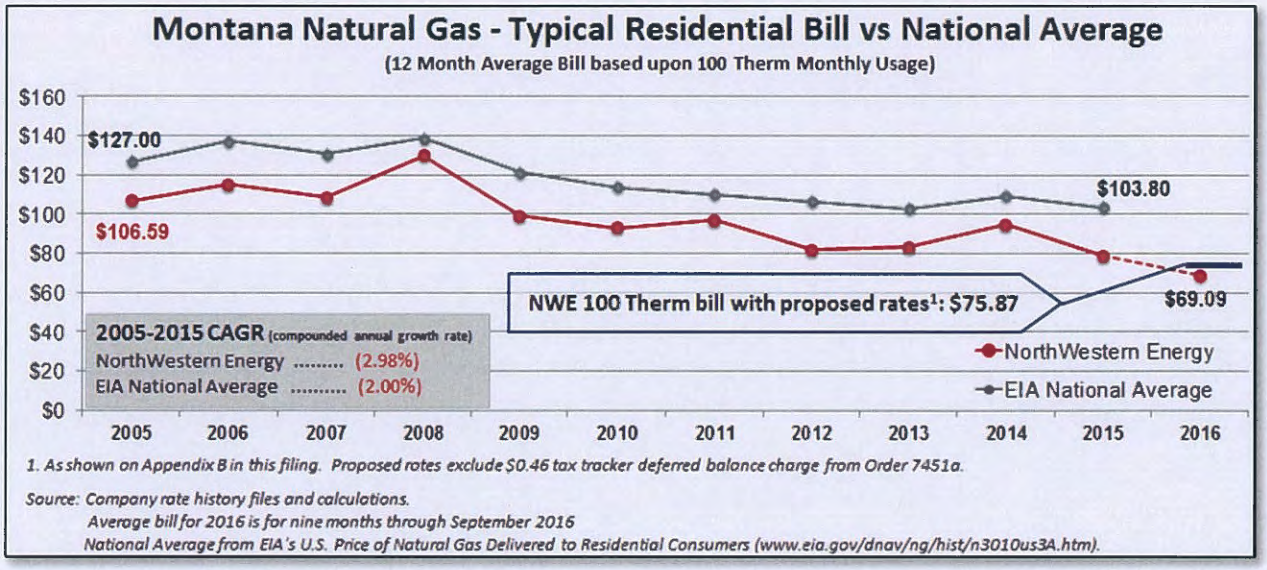
A. This filing is a traditional natural gas utility general rate request, with several additions, most notably addressing permanent treatment of the natural gas production assets, as directed by the Commission. The testimony also includes more detailed discussions of our distribution and transmission systems, which are core elements of meeting our responsibility to our customers, to Montana, and to the Commission.

The revenue requirement or cost of service portion of the filing is based on historic, actual 2015 test year data adjusted for known and measurable changes through December 31, 2016. NorthWestern requested, and the Commission granted, bifurcation of the revenue requirement determination from the allocated

cost of service/rate design portion of this proceeding. NorthWestern will file natural gas allocated cost of service studies, which revisit the apportionment of the natural gas utility costs, including the proposed revenue requirement increase, among the various customer classes, as provided by the Commission's action. NorthWestern presents an analysis of three alternative rate-making approaches for the natural gas production assets and recommends that the Commission implement an annual true-up approach.

Q. What are the overall adjustments being requested in this filing?

A. NorthWestern is requesting an annual overall increase in its natural gas utility service revenue requirement of $10,892,438, including an annual increase for the fixed cost of the production assets of $3,520,483. The requested revenue requirement, if adopted, would result in an overall uniform increase of 7.96% specific to these services. A residential customer using 100 therms per month of natural gas would see an increase in the total bill of $4.81 or 6.77%. The overall bill impact will vary by customer type and usage. The chart below illustrates the estimated typical residential 100 therm bill, if the Commission were to approve the revenue requirement as requested. A typical bill with the increase as requested would still be significantly below both NorthWestern levels over the past decade and below the U.S. Energy Information Administration (EIA) national average cost of delivered residential natural gas over the past decade.



Revenue Requirement and Cost of Service Drivers

Q. Please provide a summary of the key factors driving the need for this rate adjustment since the last natural gas general filing, which was based on a 2011 test period.

A. One key factor is declining normalized loads. In the 2011 test period, the normalized average residential load was approximately 81 dekatherms ("Dkt") per year; in the 2015 test period, it is approximately 75 Dkt per year, a decrease of 7.2%. Much of this decrease is attributable to energy efficiency, including our demand side management programs. We strongly support these are programs. Paying for fixed cost critical infrastructure almost entirely through variable rates is a challenge identified by MPSC Vice Chairman and NARUC President Travis Kavulla in a recent interview. Commissioner Kavulla stated:

In the past, commodity scarcity drove utility regulators at the Federal Energy Regulatory Commission, its predecessor the Federal Power Commission and the state commissions to conserve the commodity by including many of the costs of the delivery infrastructures with the per-dekatherm price. I am unsure that this is wise, because we are living with an abundance of the commodity. Why shouldn't the price of energy reflect the price of energy? But of course those infrastructure costs need to be recovered. That is why higher fixed charges, once disfavored, are returning to the fore of the conversation for gas utility service.

Meanwhile, there is clearly a problem when volumetric prices are used to recover fixed costs that may be unrelated to the actual volume of consumption.

Making History, American Gas Magazine, February 2016, pp. 23, 25-26.

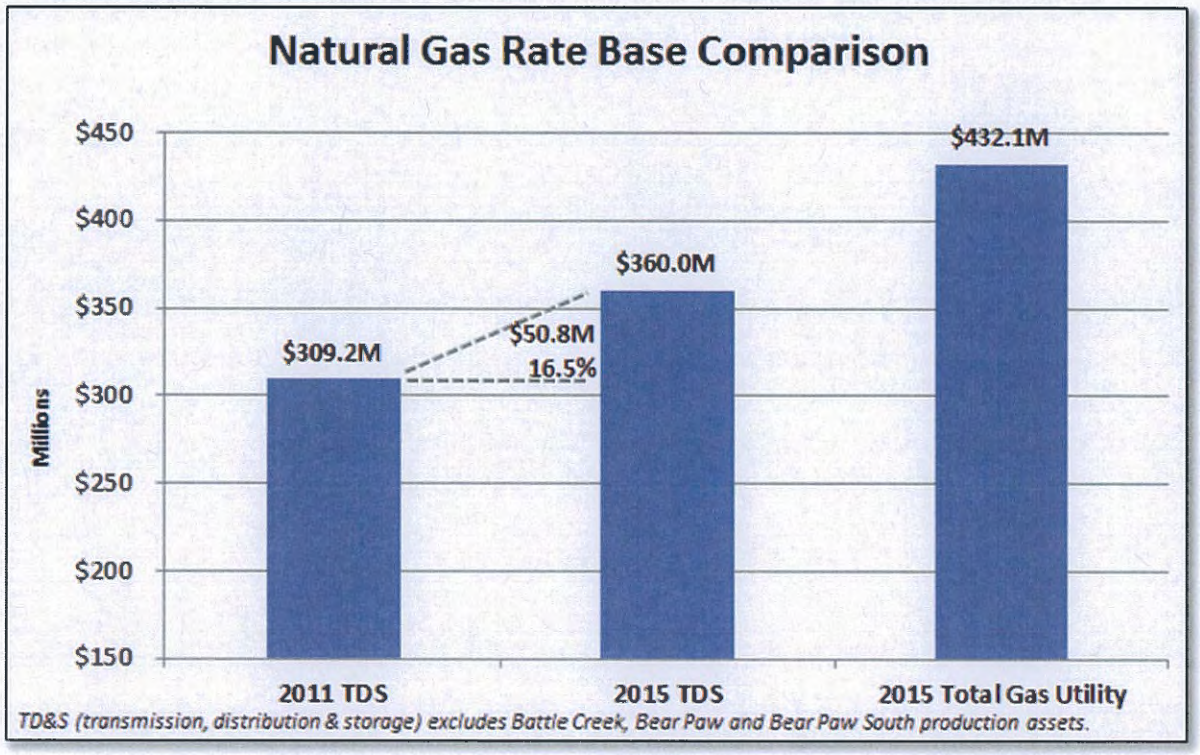
As Commissioner Kavulla suggests, some regulatory practices need to be reformed to align with the current and emerging customer and public policy expectations and trends. In particular, some form of alternative revenue-based regulation would help address the problem described by Commissioner Kavulla. A widespread tool used today is decoupling.[2]

A second key factor is increased operating, administrative, and general expenses ("OA&G"). In the 2011 test period, the natural gas transmission, distribution, and storage utility's OA&G was $48,751,155; in the 2015 test period, the comparable OA&G is $60,087,277, which also includes natural gas production. This increase is also driven by new mandates such as DIMP and PIM, and by the modest but

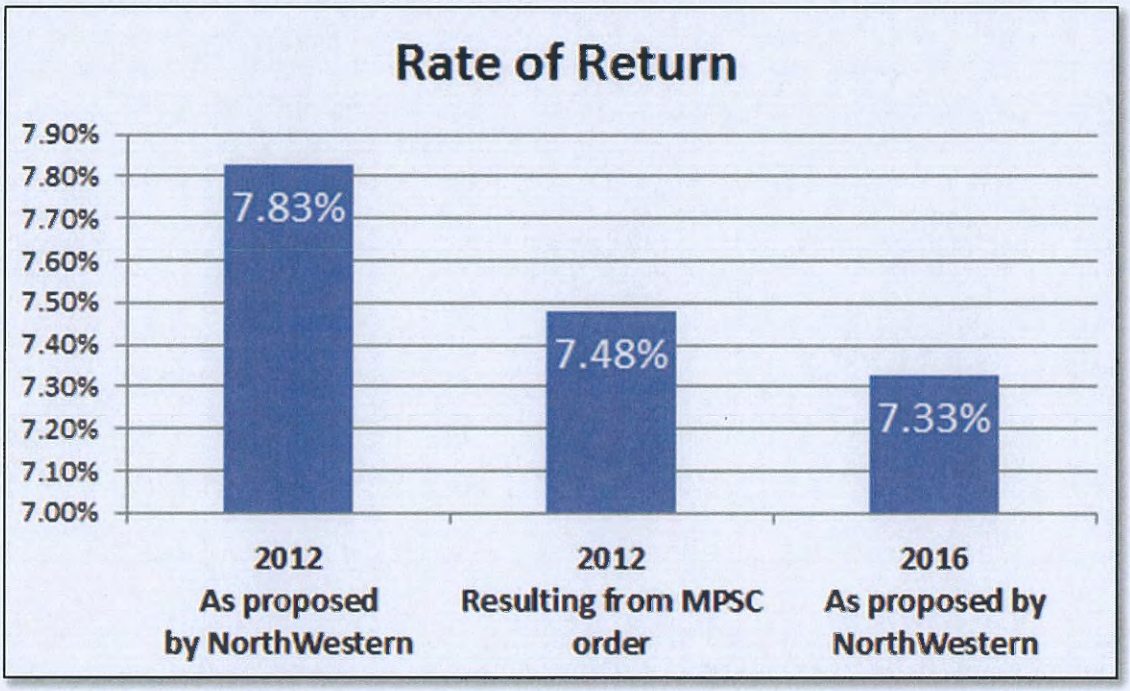
[2] There are a variety of decoupling mechanisms in operation around the country. Generally, the concept refers to some form of separation between the volume of sales of natural gas or electricity and utility revenue or returns. Goals include better aligning the utility business model with public policy and consumer goals including investing in critical infrastructure and supporting efficient resource use. NorthWestern looks forward to the Commission's decoupling roundtable on October 28th.

real inflation that has occurred since the last natural gas general rate increase. From December 2011 to December 2015, the Bureau of Labor Statistics Consumer Price Index for all items increased by 4.8%.

A third key factor is increased investment to provide service. In the 2011 test period, the natural gas transmission, distribution, and storage utility's rate base was $309.2 million; in the 2015 test period, the comparable rate base is $360.0 million, an increase of over 16%. To emphasize, this is just the transmission, distribution, and storage rate base; it does not include NorthWestern's investment in Battle Creek, Bear Paw (NFR), and South Bear Paw (Devon) production assets. Including these production assets, total investment in rate base has increased to $432.1 million.



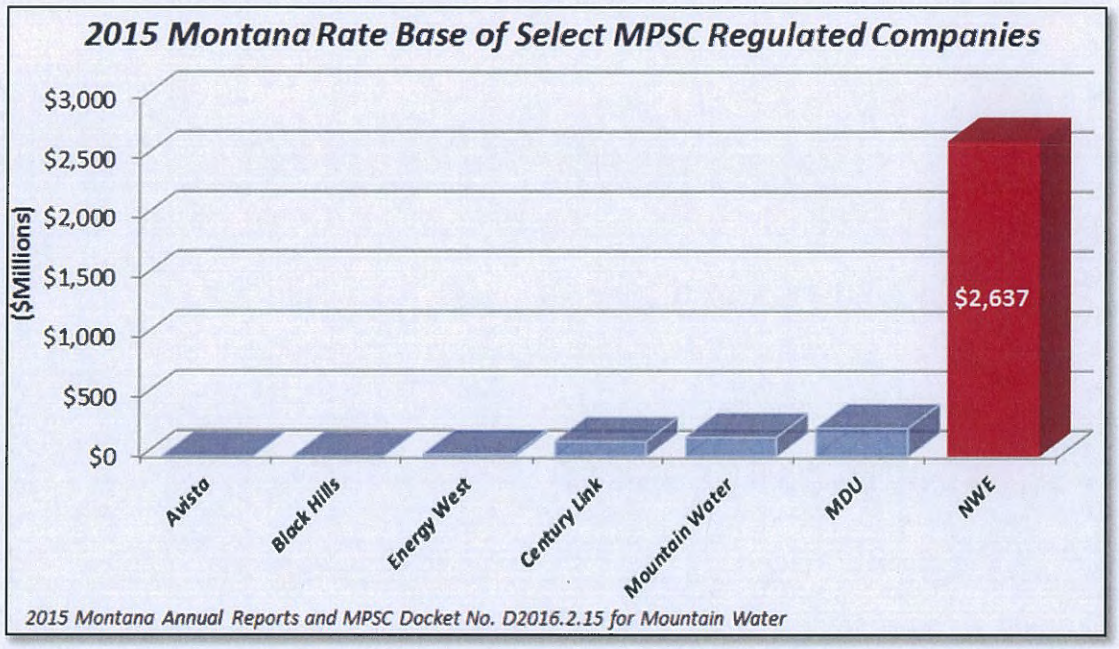
A final important part of this proceeding, as always, is the cost of capital. In 2012, NorthWestern requested an overall rate of return of 7.83% premised on a return on equity of 10.5%. The Commission authorized a return on equity of 9.8%, which resulted in a rate of return of 7.48%. In 2016, NorthWestern is requesting an overall rate of return of 7.33% premised on a return on equity of 10.35%.



Financial Health

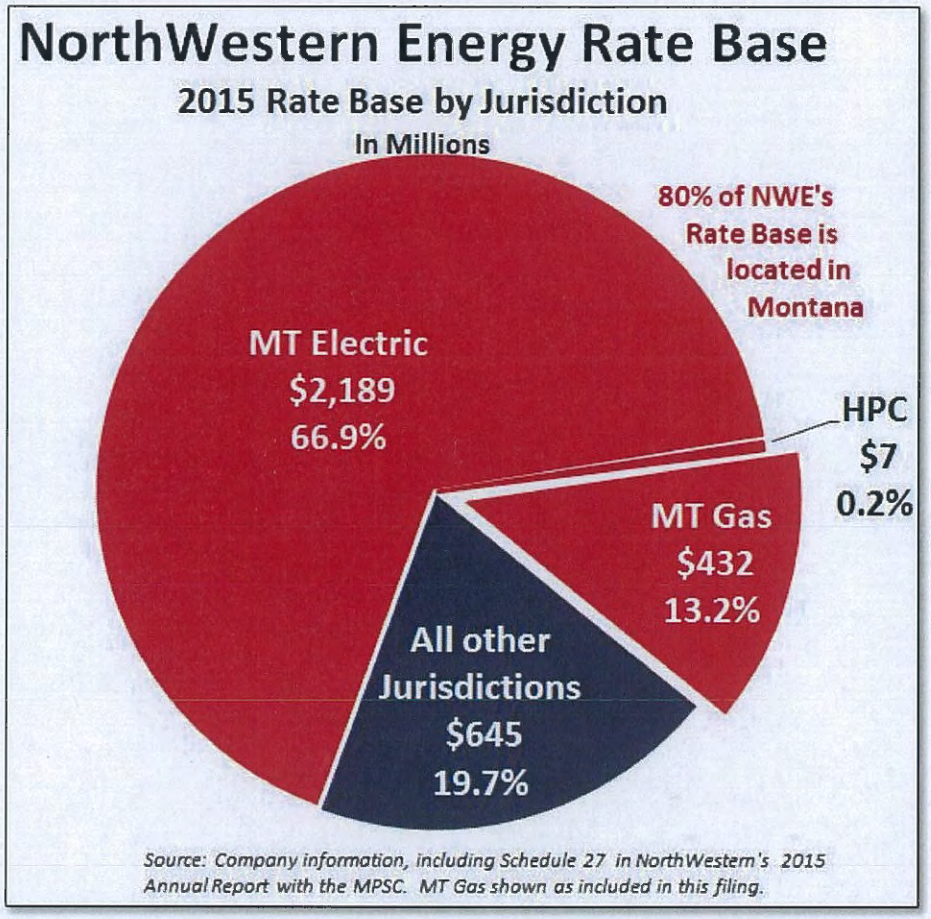
Q. How important is a utility's financial health to its customers?

A. It is vital. NorthWestern Energy's financial health turns significantly on decisions by this Commission because we are a pure utility and so much of our business is regulated by the Montana Commission. NorthWestern Energy is by far the largest state-regulated private sector critical infrastructure provider in Montana.



According to companies' filings with PHMSA, NorthWestern owns 66% of all the natural gas distribution facilities in Montana and serves 62% of all natural gas customers in the state. Our gas transmission infrastructure also supports other Montana local gas distribution companies and industrial users.

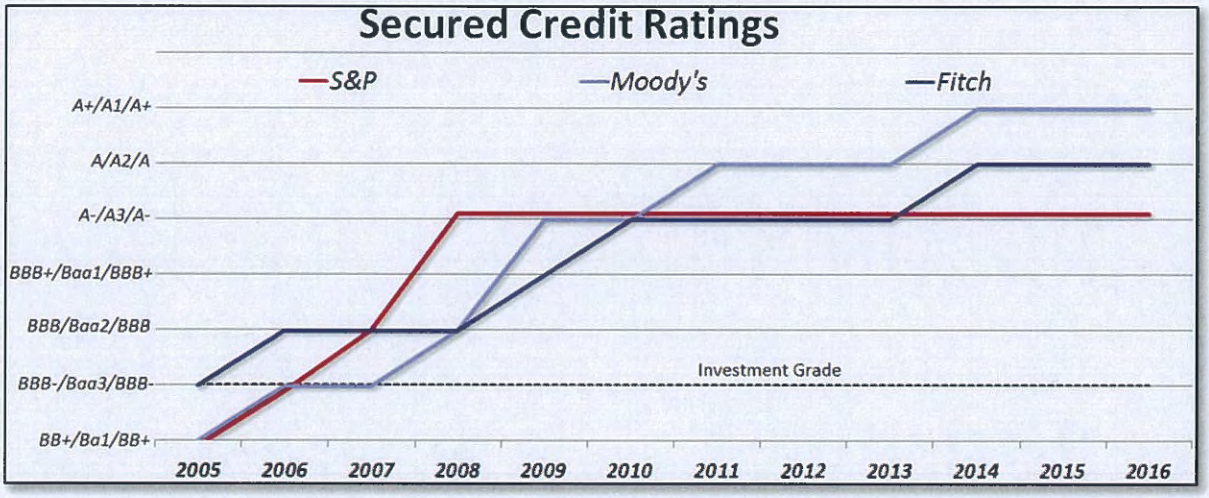
The Montana Commission regulates a dramatically larger share of our total company assets than is true for other major companies regulated by the Montana Commission. Because all of our business is regulated, and approximately 80% of it is specifically regulated by the Montana Commission, Montana regulatory decisions have a significant effect on NorthWestern's financial health.



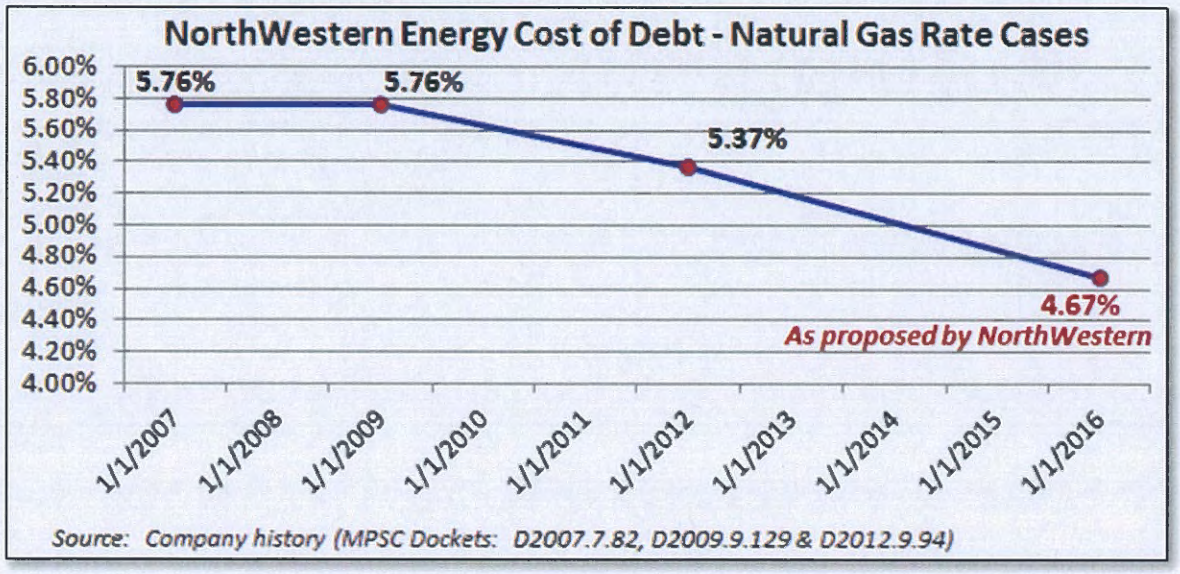
A financially sound utility is critical to Montana customers, and indeed to Montana overall, because it enables long-term asset planning and investment required to provide safe, reliable service at reasonable rates. For NorthWestern, being financially sound enables us to proceed with our DSIP, DIMP, and PIM.

NorthWestern has worked hard to earn improved confidence with both our debt and equity investors. A key measure of our increasing financial health is the improved credit ratings we have achieved from each of the rating agencies over the past ten years. As Daniel L. Rausch ("Dan") describes in his Prefiled Direct Testimony, over the prior decade we have succeeded in steadily improving our

credit ratings. The chart below demonstrates this improvement. Dan provides more detail about ratings agency views and our overall debt picture.



Trends in the larger economy are important. However, NorthWestern's cost of debt has also decreased in recent years in direct correlation to our financial performance and ratings. The decrease in the cost of debt results in a corresponding decrease in the rate of return, which benefits our customer's rates. The decrease in NorthWestern's cost of debt is illustrated in the chart below.



NorthWestern's earnings and cash flow have also improved over time, allowing us to sustainably increase our dividend to shareholders while decreasing our payout ratio (dividend per share as a percentage of earnings per share). A sustainably growing dividend contributes to overall investor confidence, helping us to compete for capital and achieve a more stable and desirable investor base, something I believe the Commission has recognized as desirable since our emergence from bankruptcy. When I joined NorthWestern in August 2008, we were covered by three equity analysts, and our largest shareholder was a hedge fund. Now, we are covered by seven analysts (listed below), with five hold ratings, one buy rating and one sell rating.

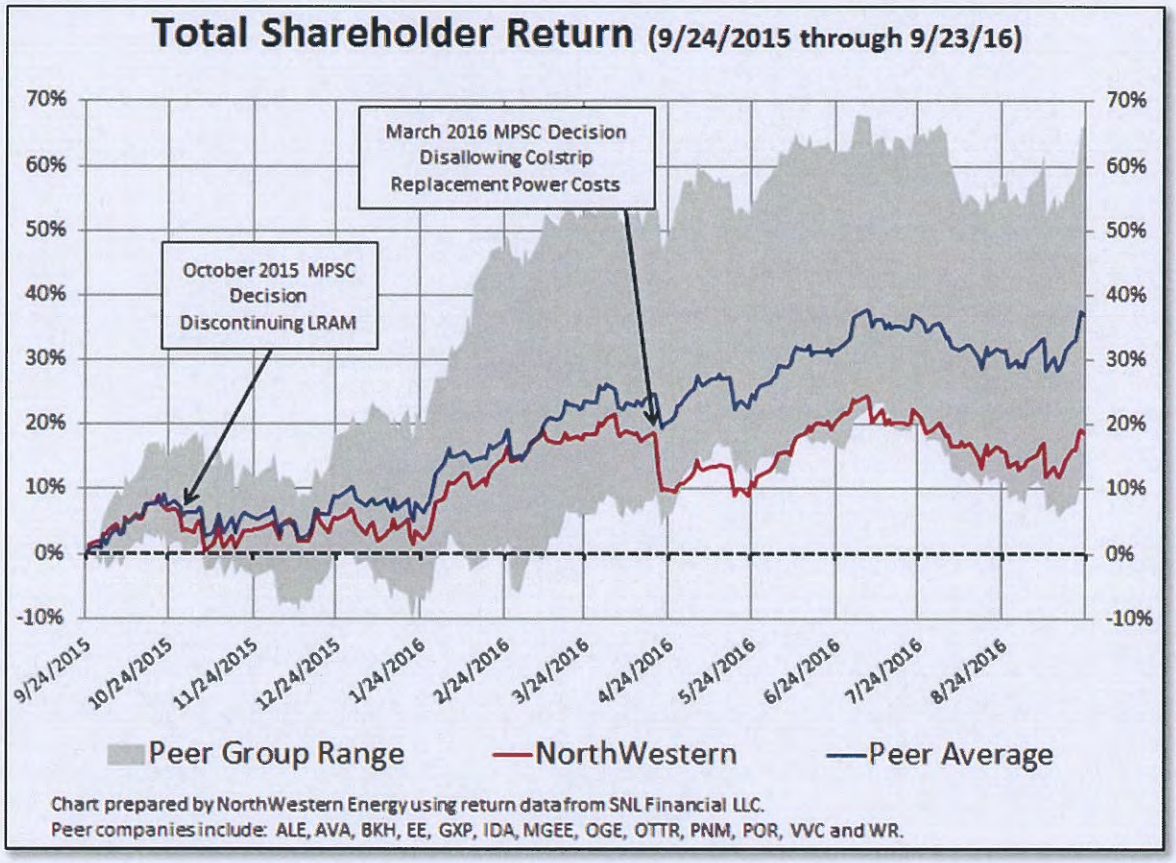
Sell-Side Firm	*Sell-Side Firm*	*Date of Report*	*Rating*
Bank of America Merrill Lynch	Brian Chin	7/22/2016	Sell
D.A. Davidson & Co.	Doug Christopher	8/19/2016	Buy
KeyBanc	Paul Ridzon	7/22/2016	Hold
Ladenburg Thalman	Brian Russo	7/22/2016	Hold
Mizuho Securities	James von Riesemann	7/22/2016	Hold
Wells Fargo Securities	Neil Kalton	7/25/2016	Hold
Williams Capital	Chris Ellinghaus	7/25/2016	Hold

(Source: Individual Equity Analyst Reports – as of 9/19/2016)

Now, our largest investors tend to be institutional investors that conduct thorough analysis and investigations before entering a stock, and – for as long as conditions are favorable – tend to stay with the stock. As the Commission knows from harsh experience, these are desirable investors for a utility that provides critical infrastructure and that necessarily must plan long-term to meet its customers' needs.

1 As part of their approach to analyzing utilities, credit ratings agencies, equity
2 analysts, and investors evaluate regulatory actions and the general "regulatory
3 environment" in which a given utility operates. Investors have told us that state
4 regulation is a core element of their evaluation. In order to be successful,
5 investors in utilities must understand the details of state regulatory practices, as
6 profitability and financial fundamentals are heavily dependent on the utility's
7 ability to earn a fair return. Long-term investors believe a thorough evaluation of
8 a state's regulatory practices over time provides the best insight into future
9 regulatory decisions. Some of the most important regulatory factors mentioned
10 by investors include returns on equity allowed and actually earned, pricing
11 structure, and the use of enhanced regulatory mechanisms. I do not suggest that
12 investor preferences or debt and equity analysts' ratings should drive regulatory
13 outcomes. I do suggest that, based on this Commission's experience, a well-
14 managed, financially sound utility able to plan for and invest in serving its
15 customers is essential to the Commission's ability to carry out its responsibilities.
16
17 In NorthWestern's case, decisions of this Commission are key contributors to
18 success or failure in achieving that mission. The chart below illustrates
19 NorthWestern's total shareholder return over the last 12 months in comparison to
20 our 13 peer company average return. While our 18.7% total return is solid on its
21 own, it is only approximately half the 37% average of our peers' return – with only
22 one peer providing a lower return to its equity owners than NorthWestern over
23 this period (Great Plains Energy, 16%). The impact of two recent and significant

1 decisions from the Commission (discontinuation of our Lost Revenue Adjustment
2 Mechanism and disallowance of the Colstrip Unit 4 replacement power costs) on
3 our stock price, and thus on shareholder return, is clearly visible in the chart
4 below.[3] We are competing for capital, and investors have many options. The
5 desirable, long-term investors we are seeking generally have a low risk appetite
6 and will choose to invest in companies that receive predictable, fair, and
7 equitable treatment from regulators.



[3] This is NOT pointed out to reargue those decisions here, or to suggest that investors only act based on regulatory decisions, but rather to highlight that Commission decisions are closely watched and acted on by investors. (For example, risk in the global or national economy can make U.S. utilities relatively more attractive investments.)

By being transparent, focused, substantive, and constructive, I believe NorthWestern is working to help enhance the "regulatory environment." In my opinion, the Commission, through its actions, can continue to improve the regulatory environment for all stakeholders, demonstrating leadership on customer-affecting energy matters. In sum, when we are financially healthy, our customers benefit.

This does not mean that the Commission, NorthWestern, or other parties always agree. It does mean that the long-term interests of our customers, Montana, and NorthWestern Energy as a regulated utility dedicated to public service should be aligned wherever possible.

Introduction of NorthWestern Witnesses

Q. Please identify the other witnesses who will testify on behalf of NorthWestern in this proceeding, and the general subject of their testimony.

A. The additional individuals who will testify in support of NorthWestern's application in this proceeding are:

Distribution, Transmission, and Storage Witnesses

- Mr. Curt T. Pohl, Vice President of Distribution, discusses NorthWestern's capital investments in the distribution system, related expenses, the natural gas DSIP project, and an overview of thinking about the future for natural gas distribution operations; and
- Mr. Michael R. Cashell, Vice President of Transmission, describes the

natural gas transmission system, the major challenges facing NorthWestern related to natural gas transmission, NorthWestern's compliance activities, including PIM, and investment in natural gas transmission projects.

Distribution, Transmission, Storage, and Supply Production Witnesses

- Mr. Adrien M. McKenzie of FINCAP, Inc., a firm providing financial, economic, and policy consulting services, presents an independent evaluation of the return on equity;
- Mr. Daniel L. Rausch, Treasurer, testifies regarding the capitalization, cost of debt, and cost of equity and rate of return for the transportation, distribution, and storage utility and for the Battle Creek, Bear Paw (NFR), and South Bear Paw (Devon) properties;
- Ms. Crystal D. Lail, Vice President and Controller, attests to the accuracy of the actual accounting data presented in the filing, explains the development of the rate base and associated depreciation and depletion expense for the Battle Creek, Bear Paw (NFR), and South Bear Paw (Devon) properties, discusses allocation of shared administrative costs, and explains certain normalizing adjustments to test year data;
- Mr. Wayne M. Hitt, Director – Corporate Taxes, supports all income and property tax related items included in the filing;
- Mr. John S. Canavan, Manager of Gas Transmission Services, explains proposed changes to the general terms and conditions in two

of NorthWestern's natural gas tariff's schedules;

- Mr. Paul M. Normand, Principal with Management Applications Consulting, Inc., presents a lead-lag study and testifies as to the cash working capital net lag days;
- Mr. Patrick J. DiFronzo, Manager, Regulatory Affairs, supports operating revenues and the retail loads used to develop operating revenues for the natural gas utility. He presents the development of the revenue requirements for the Battle Creek, Bear Paw (NFR), and South Bear Paw (Devon), true-ups of revenues for prior years for Bear Paw (NFR) and South Bear Paw (Devon), and the development of multi-year revenue requirements for the natural gas production assets. He explains certain normalizing adjustments to test year data, and also sponsors the income statement, the test period cost of service, and the revenue requirement exhibit, which demonstrate the revenue requirement deficiency for the natural gas utility;
- Mr. John M. Smith, Manager of Montana Gas Supply, details NorthWestern natural gas customers, presents a map of the natural gas system, explains NorthWestern's annual and peak supply requirements, and discusses issues regarding the availability of natural gas for NorthWestern's system;
- Mr. Bleau J. LaFave, Director of Long Term Resources, describes NorthWestern's evaluation process, acquisition process, and the benefits to customers for each of NorthWestern's natural gas

production acquisitions. He explains how each of the acquisitions fits the criteria established in NorthWestern's natural gas supply resource plan;

- Mr. Travis E. Meyer, Director of Investor Relations and Corporate Planning, explains the evaluation models and resulting revenue requirements used in the acquisition process for the Bear Paw (NFR) and South Bear Paw (Devon) production properties;
- Mr. Patrick E. Callahan, Director of Gas Growth and Storage, testifies regarding NorthWestern's acquisition of the Bear Paw (NFR) and South Bear Paw (Devon) properties, along with related assets. He also testifies about the sale of oil properties that were included with the Bear Paw (NFR) assets;
- Mr. Stephan R. Smith, Petroleum Engineer, presents his reserves reports for the Bear Paw (NFR) and South Bear Baw (Devon) natural gas production properties, particularly the proved developed producing reserves and the income forecasts;
- Mr. Thomas K. Hohn, Petroleum Engineer of Hohn Engineering, discusses his reserves report and the proved developed producing reserves for the Black Hills Corporation's production assets; and
- Mr. John D. Hines, Vice President of Supply, explains NorthWestern's approach to managing its natural gas portfolio, the benefits to customers of utility-owned natural gas production assets,

1 NorthWestern's approach to evaluating and purchasing production
2 assets, and NorthWestern's perspective about future acquisitions.
3 **Future Ratemaking Treatment of Production Assets**
4 • Mr. Patrick R. Corcoran, Vice President of Government and
5 Regulatory Affairs, addresses the appropriate ratemaking treatment for
6 the natural gas production assets.
7
8 **Q. Does this conclude your testimony?**
9 **A.** Yes.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF CURTIS T. POHL

ON BEHALF OF NORTHWESTERN ENERGY

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Exhibits

PHMSA[1] DOT form 7100	Exhibit__(CTP-1)
Gas Distribution Historic Expenses	Exhibit__(CTP-2)

[1] Pipeline and Hazardous Materials Safety Administration ("PHMSA")

Witness Information

Q. Please state your name and business address.

A. My name is Curtis T. Pohl. My business address is 11 East Park, Butte, Montana 59701.

Q. By whom are you employed and in what capacity?

A. I work for NorthWestern Energy ("NorthWestern" or "Company") as Vice President of Distribution.

Q. Please summarize your education and employment experience.

A. I graduated from South Dakota State University with a Bachelor of Science degree in Mechanical Engineering in 1986. In July of 1987, I received focused gas engineering training at the Institute of Gas Technology in Chicago. I attended the Utility Executive Course at the University of Idaho in June of 2006. Also, I have attended several operation and leadership training sessions over the course of my career and have been active in industry associations as a member of various committees and as a board member.

I started my career at NorthWestern (previously Northwestern Public Service) in 1986 as a gas engineer in Grand Island, Nebraska. I spent four years in this position, primarily working with day-to-day operations in Nebraska, on gas distribution design, standards, and project management. In 1990, I moved to Huron, South Dakota as Director of Gas Engineering, where I was

1 primarily responsible for overall gas engineering and construction. I became
2 Manager of Gas Operations in 1992; I was responsible for all aspects of the
3 gas operations in South Dakota and Nebraska. In 1998, I accepted a
4 promotion to Vice President of Engineering and Construction where I had
5 responsibility for all engineering and construction for electric and gas
6 operations in South Dakota and Nebraska. When NorthWestern acquired the
7 transmission and distribution assets of the Montana Power Company in 2002,
8 I held the position of Vice President of South Dakota and Nebraska
9 Operations, and in 2003, I moved to Montana to take my current position as
10 Vice President of Distribution. In this role, I have the primary responsibility for
11 gas and electric distribution operations across Montana, South Dakota, and
12 Nebraska.
13
14 **Purpose of Testimony**
15 **Q. What is the purpose of your testimony in this proceeding?**
16 **A.** The purpose of my testimony is to describe the overall natural gas distribution
17 operations in Montana and NorthWestern's approach to providing safe,
18 reliable, and affordable natural gas service to our customers. I specifically
19 discuss:
20 • the capital investments NorthWestern has made in the natural gas
21 distribution system from 2012 through 2015;
22 • the related necessary distribution and other supporting expenses;

- NorthWestern's Distribution System Infrastructure Project ("DSIP") as it relates to natural gas, made up of both capital and expense components, and why it made sense to implement this program; and
- a glimpse of the future for natural gas distribution operations in Montana.

Natural Gas Distribution System

Q. Please provide a general description of NorthWestern's natural gas distribution operations in Montana.

A. NorthWestern operates a natural gas distribution system that includes 4,686 miles of main pipeline with 185,514 services at the end of 2015. This system serves approximately 189,400 customers in 117 communities. Our total distribution system breakdown with main and service pipeline material, sizes, and vintage is shown in our Pipeline and Hazardous Materials Safety Administration ("PHMSA") Annual Report for Calendar Year 2015 Gas Distribution System, attached as Exhibit__(CTP-1).

This system connects to NorthWestern's natural gas intrastate transmission system described in the Prefiled Direct Testimony of Michael R. Cashell ("Cashell Direct Testimony") at city gate stations where the gas is measured and the transmission gas pressure is reduced to distribution pressures. The distribution system operates through various networked systems where maximum allowable operating pressures range from 15 pounds per square

inch gage ("psig") to 150 psig. Major equipment that is maintained includes the pipeline main and services, pressure regulating stations, sectionalizing valves, and customer meters and associated equipment.

Natural Gas Operations

Q. Please describe how NorthWestern's Montana natural gas operations are organized in the field.

A. Distribution Operations is organized into six Division Operations ("Divisions") with five Districts reporting to their respective Divisions as follows:

1. Billings Division
    - A. Lewistown District
2. Bozeman Division
    - A. Livingston District
3. Butte Division
4. Helena Division
5. Great Falls Division
    - A. Havre District
6. Missoula Division
    - A. Kalispell District
    - B. Hamilton District

Each Division has an Operations Manager and a Construction Manager. Reporting to the Operations Manager are the Gas Supervisor specifically

1 responsible for all of the gasmen that execute day-to-day gas operations
2 within the Division and the District Managers that have responsibility for the
3 gas operations within their respective Districts. Reporting to the Construction
4 Manager are the engineers and estimators responsible for engineering and
5 managing gas construction projects.
6
7 Currently there are 89 employees dedicated to Gas Distribution Operations,
8 maintenance, and construction, with approximately 40 other employees in
9 combination electric and gas operations and maintenance roles in small
10 towns, and supervision and engineering within the Divisions.
11 The General Manager of Operations and the General Manager of
12 Construction supervise and support the Divisions.
13
14 **Q. Please describe the centralized functions that support Gas Distribution**
15 **Operations.**
16 **A.** There are several centralized departments that support our distribution field
17 operations as follows:
18 • Asset Management has primary responsibility for capacity planning in
19 the natural gas distribution system as well as developing the overall
20 maintenance and investment strategies that ensure the safety and
21 reliability of our gas distribution system. This group is also responsible
22 for overall Department of Transportation ("DOT") pipeline safety
23 compliance and NorthWestern's damage prevention program, which

focuses on preventing third party damage to the system. Also, this group manages and executes the work necessary for corrosion control on our natural gas distribution system.

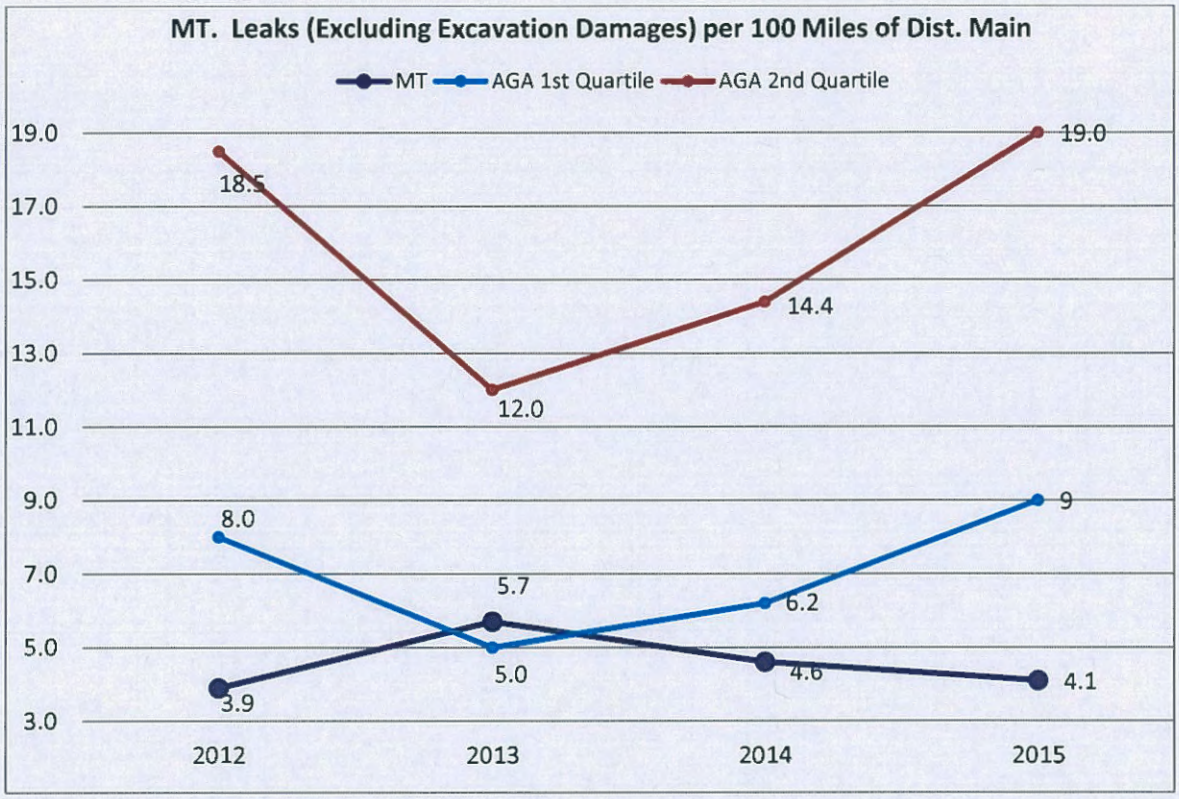
- Organizational Performance has responsibility to ensure maintenance and investment plans developed by Asset Management are executed within budget guidelines. They also assist the field operations in constant process improvement and workforce planning.
- Major Project Management is responsible for managing projects that generally exceed $1,000,000 and/or are multi-year projects. In Gas Distribution, this group's primary project is the DSIP.
- Support Services provides logistics support for warehousing and material procurement, facilities, and fleet.
- Safety supports all safety programs, procedures, and training; it investigates any safety-related incidents that occur.

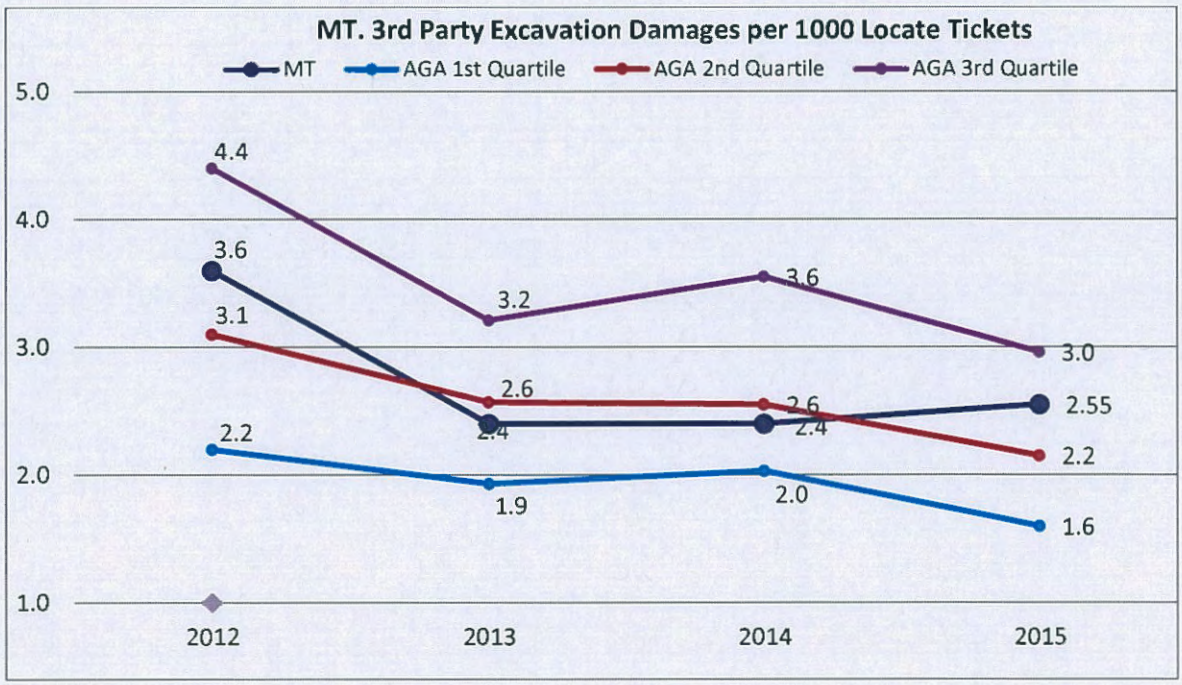
Q. Please describe NorthWestern's Gas Distribution Operations' approach to the provision of safe, reliable, and affordable natural gas service.

A. Our number one goal is the safety of our workforce and the safety of the public. We attain this goal by maintaining our system to minimize gas leaks while providing quality and timely customer service. We pride ourselves on a highly qualified workforce and undertake continual planning to maintain this workforce into the future. We have developed a culture that embraces

continual work process improvement. We perform the appropriate work in accordance with all pipeline safety requirements to maintain a safe and reliable system but also focus on efficiency, resulting in high quality service at affordable rates. Our overall asset management approach is fundamental but very effective. By utilizing this approach we are able to analyze the data that is produced through inspections and system performance monitoring to plan and prioritize investments and implement maintenance plans that maximize the safety and overall performance of our system.

The following graphs show distribution system leak performance over the past four years benchmarked against peer company members of the American Gas Association. Our distribution gas systems perform at a high level in leaks per 100 miles of main. We have made great progress over the past four years in addressing third party damage, but this is an area we need to continue to focus on through our damage prevention programs.


MT. Leaks (Excluding Excavation Damages) per 100 Miles of Dist. Main
MT
AGA 1st Quartile
AGA 2nd Quartile
19.0
17.0
15.0
13.0
11.0
9.0
7.0
5.0
3.0
18.5
12.0
14.4
19.0
8.0
5.0
6.2
9
3.9
5.7
4.6
4.1
2012
2013
2014
2015


MT. 3rd Party Excavation Damages per 1000 Locate Tickets
MT
AGA 1st Quartile
AGA 2nd Quartile
AGA 3rd Quartile
5.0
4.0
3.0
2.0
1.0
4.4
3.2
3.6
3.0
3.6
3.1
2.6
2.6
2.2
2.4
2.4
2.55
2.2
1.9
2.0
1.6
2012
2013
2014
2015

1 **Q. Please further describe Asset Management's role in Gas Distribution**
2 **Operations and the initiatives developed to assure that NorthWestern's**
3 **natural gas service is safe, reliable, and affordable.**
4 **A.** Asset Management is the foundation of our distribution gas operations. This
5 group of highly qualified people is dedicated solely to analyzing the data that
6 our system produces and soliciting feedback from field operations to develop
7 investment and maintenance plans that maintain our system performance for
8 both the short and the long term. They are also responsible for capacity
9 planning by modeling our distribution systems under peak loading conditions
10 and planning appropriate system upgrades to ensure the overall reliability of
11 our system. This group has responsibility for overall pipeline safety
12 compliance in coordination with the Montana Public Service Commission
13 ("MPSC") staff to ensure that we are in compliance with all current PHMSA
14 (DOT) regulations.
15
16 An example of the work that Asset Management completed is our current
17 Distribution Integrity Management Plan ("DIMP"). This plan was based on
18 analysis of bell-hole reports generated by field personnel that indicate the
19 condition of our pipelines each time we expose a piece of main, and on other
20 field-generated reports and system leak reports. These reports, in addition to
21 input provided by field employees and subject matter experts, were used to
22 better understand the overall condition of our system and develop the DIMP.
23 This plan identifies accelerated actions that are necessary to address areas

that impose higher threats to our system in order to maintain system integrity. These actions take higher priority when planning replacement or maintenance activities. Asset Management was also responsible for the development of our DSIP plan currently being executed. I describe DSIP in more detail below.

Q. Please describe the role of the Operations and Construction groups and the initiatives developed to assure that NorthWestern's natural gas service is safe, reliable, and affordable.

A. The Operations and Construction groups execute the plans that are developed by Asset Management. The Operations group supervises our field workforce and develops and implements the overall work plans to carry out all maintenance. This includes pipeline safety compliance, customer service, and construction activity completed by our internal crews. The Gas Operations work plan is broken into 39 activities, which correlate to Federal Energy Regulatory Commission ("FERC") accounts. The major categories that these activities fall into include:

1. Gas Compliance – These are maintenance activities necessary to comply with pipeline safety regulations such as annual regulator station maintenance and leak surveys.
2. Customer Service – These activities are related to work completed on customer premises such as connects/disconnects, odor calls, etc.

3. Proactive Gas System Maintenance – These activities are planned repairs to the system or inspections not associated with compliance.
4. Reactive Gas System Maintenance – These activities include inspection, investigation, or repairs to the system that must be done as soon as practical.
5. Non-Productive Time – These are the associated activities for our craft workforce that involve training, other meetings, and paid time off.
6. Supervision and Engineering.

Each activity is based on units of work so that over time we have developed a history of labor costs per unit and total costs per unit. We use this historical information to monitor trends and prioritize and plan work. This helps us become more efficient with work planning and process improvement. The other main advantage to this tracking method is the visibility and availability of our work plans to supervisors so they can actively manage work activity and make informed decisions and any necessary adjustments based on this readily accessible information.

A good example of effective use of this information is the notification process that NorthWestern developed for almost every activity. The notification process is an electronic process that creates work orders within our system enterprise system, SAP. Orders are work tasks that need to be completed.

1 These orders can then be prioritized, put into our work planning process,
2 dispatched, and completed efficiently. Another key component of the
3 notification process is the data collection that is critical to feed our asset
4 management process described above. The notification process is also
5 critical for compliance purposes; operating supervision personnel have ready
6 access to the information necessary to ensure all compliance work activity is
7 completed in accordance with pipeline safety codes.
8
9 **Q. What challenges does NorthWestern face in operating its natural gas**
10 **distribution system?**
11 **A.** NorthWestern faces several challenges in operating its natural gas
12 distribution system. We have a large service area with low customer density.
13 While we serve natural gas to many larger cities such as Bozeman and
14 Missoula, we also serve many rural areas and small towns. Our workforce
15 has to be dispersed in order to cover emergency response in a timely
16 manner, making it more difficult to maximize the efficiency of this workforce.
17 In our service territory, there is generally not enough work activity in any of
18 our major categories to specialize the skillsets of our workforce. Therefore,
19 our workforce must be trained and qualified to perform a variety of tasks so
20 that productivity can be maximized. We have maintained our system to high
21 standards of performance, but our system is aging. It is critical to monitor the
22 system, make the essential investments, and perform the maintenance
23 necessary to sustain a safe and reliable system. Current and future changes

to pipeline safety regulations are also challenging. While we embrace new regulations where it makes sense to enhance overall safety, new regulations generally mean additional costs.

Distribution System Infrastructure Project

Q. Please describe the DSIP.

A. The DSIP is a comprehensive distribution infrastructure plan for both the gas and electric utilities that was implemented as a supplement to NorthWestern's existing base maintenance and capital investment plans. It is designed to accomplish a specific set of goals and to address some of the challenges of maintaining safe and reliable systems that could not be met by our existing base plans.

The overall goals for the DSIP plan for the natural gas distribution system are:

1. Embrace the industry's new safety model (DIMP);
2. Employ state-of-the-art analytical skills to proactively manage safety, and
3. Improve or, at a minimum, maintain leak rate performance.

The DSIP plan is a seven-year plan that began in 2011. The first two years were intended to be phase-in years with full production starting in 2013. In an effort to keep the MPSC informed, we provide quarterly updates on our progress with DSIP.

1 **Q. How was the DSIP plan developed and why was it necessary?**

2 **A.** As described earlier we have adopted a strong asset management mentality
3 utilizing operating performance data along with field input and expertise to
4 develop our maintenance and investment plans for our distribution systems.
5 In 2009 we recognized that system performance would begin to slip over time
6 if we did not proactively address and improve certain components of our
7 distribution systems. In natural gas distribution specifically we also
8 recognized that better processes were needed to collect operating
9 performance data to give us the ability to analyze information and make more
10 informed decisions related to maintenance and capital investments necessary
11 to ensure our system would be safe and reliable.
12
13 The DSIP plan was developed by Asset Management, in a collaborative
14 process that involved many internal departments, especially our Finance and
15 Regulatory groups. In 2009 and 2010, we engaged in an infrastructure
16 stakeholder process which included members from across Montana with
17 representation from legislators, county commissioners, municipalities, retail
18 customers, industrial customers, electric cooperatives, labor unions, the
19 Montana Consumer Counsel, and MPSC staff. The stakeholder process was
20 instrumental in developing the overall guiding principles and the goals that
21 ultimately were established for the DSIP plan. We continue to use the
22 stakeholder process to gather input on current and future infrastructure plans.

1 **Q. Please describe the natural gas distribution components of the DSIP**
2 **plan and the costs associated with those components.**
3 **A.** The table below shows the actual expenses incurred to implement the DSIP
4 plan through 2015. The expenses recorded in the Gas Amortization line
5 include the expenses incurred in 2011 and 2012 per the approval of an
6 accounting order, Order No. 7138, Docket No. D2011.1.7. Approximately
7 $3,000,000 was incurred during 2011 and 2012, primarily to expand our
8 Geographic Information System platform for gas and to create the necessary
9 framework to implement the DIMP. In 2011 and 2012 we also initiated a
10 process to increase our sectionalizing capability by adding more zone valves
11 in business districts and incurred the related expenses in those years. A
12 large portion of DSIP expenses for 2013 through 2015 activities was incurred
13 for the Damage Prevention Initiative. This program was developed
14 specifically to address third party damage. As the chart above regarding
15 damages per 1,000 locates shows, we have made significant progress over
16 the past four years in this area.

Natural Gas DSIP Expenses by Activity

	Actual			
	2012	2013	2014	2015
DSIP-Dist Integrity Mgmt Prog		28		
DSIP-Zone Valve Installation		36,262	17,962	
DSIP-Non-Business Inside Mtr		26,740	3,229	
DSIP-Gas Line Damage Preventi		243,953	468,648	618,761
DSIP-Gas Line Stub Removal		345		
DSIP-Farm Tap Rebuild		17,539		44,884
DSIP-Gas Main Repairs G1		961	2,884	1,686
DSIP-Gas Service Repairs G1		400,991	193,133	351
DSIP-Gas Meter Repair G1		69,489	13,688	
DSIP-Gas Amortization		603,346	603,346	603,346
**** Total DSIP Gas Expense**		**1,399,654**	**1,302,888**	**1,269,028**

Even though the formal DSIP plan is scheduled to be completed by the end of 2017 NorthWestern anticipates that it will be necessary to continue incurring expenses at or above these levels beyond that time frame. We fully expect to continue our damage prevention program and expand it as necessary. We will also need to continue to meet the requirements of our DIMP program and continue to incur expenses related to maintaining an aging system into the foreseeable future.

The capital expenditure ("CapEx") - investments associated with the DSIP plan for gas distribution from 2012-2015 are shown in the following table:

DSIP Gas Distribution CapEx		2012	2013	2014	2015	Total
	DSIP Gas Business Districts	5,205,466	4,631,197	5,096,724	0	14,933,388
	DSIP Zone Valves	721,775	5,354	(0)		727,129
	DSIP Gas One				5,285,191	5,285,191
	DSIP Gas DIMP	168,774	9,546			178,320
	DSIP Inside Mtr Serv Repl		171,232	175,210		346,442
	DSIP Farm Taps		214,117	115,244	113,080	442,441
	DSIP Gas Service Stubs		494,316	19,460		513,776
	DSIP Gas Line Under Structures		815,398	684,524		1,499,922
	DSIP Other	128,280				128,280
	DSIP Zones Valves				15,247	15,247
Total CapEx		6,224,295	6,341,159	6,091,162	5,413,518	24,070,134

In 2015 we created the Gas One Plan, which encompasses the Business District and Non-Business District Inside Meter Set and Vintage Construction Improvements Capital Component, Gas Line Stub Removal, and Gas Lines Under Structures Removal or Relocation Capital Component (DSIP and Base). In the Gas One Plan, we are using data that is now available to identify higher threat components of our system and inventory those threats to city blocks. This allows us to prioritize the highest needs for upgrades by city block and address several single component items by attacking them on a block-by-block basis. The resulting construction project is much more efficient than the previous approach.

1 **Natural Gas Distribution System Expenses and Investments**

2 **Q. Describe the distribution operating and maintenance expenses**
3 **necessary to achieve NorthWestern's safety and reliability goals.**

4 **A.** In 2015, our actual distribution gas operating and maintenance expenses,
5 including DSIP, were $14,584,602. The books and records of the Company
6 show these expenses by the standard FERC chart of accounts. As stated
7 earlier in my testimony, we track our expenses by activities that match their
8 appropriate FERC accounts. By managing our business in this fashion, we
9 have greater access to and understanding of our actual costs and are able to
10 manage our business much more efficiently to provide safe, reliable, and
11 affordable service. The following table shows 2012-2015 direct gas expenses
12 by operating and maintenance high level category. The detailed expenses by
13 activity are shown in Exhibit__(CTP-2).

Historic MT direct Distribution Gas Expense
By Activity 2012-2015

	Actual			
	2012	2013	2014	2015
** MT Compliance Gas	998,462	1,110,349	1,043,090	1,009,162
** MT Customer Gas	4,002,356	4,055,332	3,994,124	3,827,248
** MT Proactive Gas	1,366,562	1,696,111	1,528,614	1,418,281
** MT Reactive Gas	1,135,500	1,204,387	1,229,858	1,211,087
** MT Non-Productive Time	2,137,526	2,253,627	2,415,279	2,419,079
** MT Supervision & Engineering	1,133,198	1,149,136	1,134,587	1,182,144
*** Total Field Operations	10,773,602	11,468,942	11,345,553	11,067,000
** Total DSIP Gas Expense		1,399,654	1,302,888	1,269,028
** Corrosion Control	1,128,070	1,133,535	1,274,742	1,302,633
* Meter Shop-Montana	352,100	382,464	409,754	416,046
*** Total Central Maintenance Gas Expense	1,480,170	1,515,999	1,684,497	1,718,679
Total Operations and Maintenance Expense	12,253,772	14,384,594	14,332,937	14,054,707

The difference between the 2015 total operating gas distribution operating expenses of $14,584,602 and the direct expenses shown in the table above are the expenses allocated from shared Electric and Gas Supervision, Engineering and Administrative functions.

Q. Describe the capital investments that have been made to achieve NorthWestern's safety and reliability goals.

A. As of year-end 2011, the original cost of natural gas distribution plant was $240,675,470 and net book value was $135,468,052. At year-end 2015, the original cost of gas distribution plant was $293,533,913 and net book value was $169,800,090. During this time frame NorthWestern invested

$52,858,442 into its distribution system while over this same time frame depreciation expense totaled only $18,526,406; the result is an increase in net book value of $34,332,038.

As described previously we invested approximately $24,000,000 over this period in the DSIP plan. The other major categories of CapEx over the past four years include approximately $15,000,000 in growth projects to install new main and services to connect new customers, with capacity projects and other proactive maintenance CapEx projects to ensure reliability making up the balance.

Future Distribution Operations Challenges

Q. Describe some of the challenges for Montana's Gas Distribution Operations going forward.

A. NorthWestern is challenged to meet the need to continue to invest in our natural gas distribution infrastructure at the current pace into the foreseeable future. Although we have made great progress over the past four years, we still have an aging system that requires significant investment over the next several years in order to maintain overall safety and reliability. Exhibit__(CTP-1) shows that approximately 23% of our main and 33% of our services were installed prior to 1970. Age is not the primary factor that determines the integrity of the distribution system; however, it is a data point to consider in our overall management of the distribution assets. We are in

1 the process of updating our DIMP, which is required every five years. Most of
2 the accelerated actions identified through data analysis and verified as
3 necessary and appropriate by subject matter experts indicates that our
4 investment and maintenance strategies are currently on point. We plan to
5 continue investing into the future using our established methods to address
6 installations under older construction practices with the continued execution
7 of our Gas One Plan. However, we will make some adjustments to this plan
8 to focus on some of our identified acceleration actions sooner by
9 implementing programs targeted at specific components, such as inside
10 meter fits. Continued new compliance regulations will put upward pressure
11 on operating costs. An example of this is the new operator qualification
12 requirements proposed by PHMSA. We will continue to look for and
13 implement efficiencies in work practices to help offset labor increases.
14 Through process improvements and technology, we will continue to promote
15 more efficient data collection, work planning, and work execution. In general,
16 due to all of these actions, our Distribution Operations functions at very high
17 performance levels today and will continue to do so into the future to provide
18 safe, reliable, and affordable service for our customers.
19
20 **Q. Does this conclude your testimony?**
21 **A.** Yes.

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.		OMB NO: 2137-0629 EXPIRATION DATE: 5/31/2018
U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Initial Date Submitted:**	03/08/2016
	Form Type:	INITIAL
	Date Submitted:	

ANNUAL REPORT FOR CALENDAR YEAR 2015 GAS DISTRIBUTION SYSTEM

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0629. Public reporting for this collection of information is estimated to be approximately 16 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline/library/forms.*

PART A - OPERATOR INFORMATION	**(DOT use only)**	**20165361-27907**

1. Name of Operator	NORTHWESTERN ENERGY LLC
2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED)	
2a. Street Address	11 E PARK ST
2b. City and County	BUTTE
2c. State	MT
2d. Zip Code	59701
3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER	31632
4. HEADQUARTERS NAME & ADDRESS	
4a. Street Address	3010 W. 69TH ST.
4b. City and County	SIOUX FALLS
4c. State	SD
4d. Zip Code	57108
5. STATE IN WHICH SYSTEM OPERATES	MT
6. **THIS REPORT PERTAINS TO THE FOLLOWING COMMODITY GROUP** *(Select Commodity Group based on the predominant gas carried and complete the report for that Commodity Group. File a separate report for each Commodity Group included in this OPID.)*	
Natural Gas	
7. **THIS REPORT PERTAINS TO THE FOLLOWING TYPE OF OPERATOR** *(Select Type of Operator based on the structure of the company included in this OPID for which this report is being submitted.)*:	
Privately Owned	

PART B - SYSTEM DESCRIPTION

1.GENERAL

	STEEL				PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	RECONDITIONED CAST IRON	SYSTEM TOTAL
	UNPROTECTED		CATHODICALLY PROTECTED								
	BARE	COATED	BARE	COATED							
MILES OF MAIN				1228	3458						4686
NO. OF SERVICES				67591	117923						185514

2.MILES OF MAINS IN SYSTEM AT END OF YEAR

MATERIAL	UNKNOWN	2" OR LESS	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8" THRU 12"	OVER 12"	SYSTEM TOTALS
STEEL	0	788	296	122	20	2	1228
DUCTILE IRON	0	0	0	0	0	0	0
COPPER	0	0	0	0	0	0	0
CAST/WROUGHT IRON	0	0	0	0	0	0	0
PLASTIC PVC	0	0	0	0	0	0	0
PLASTIC PE	0	2643	555	248	12	0	3458
PLASTIC ABS	0	0	0	0	0	0	0
PLASTIC OTHER	0	0	0	0	0	0	0
OTHER	0	0	0	0	0	0	0
RECONDITIONED CAST IRON	0	0	0	0	0	0	0
TOTAL	0	3431	851	370	32	2	4686
Describe Other Material:							

3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR — **AVERAGE SERVICE LENGTH: 82**

MATERIAL	UNKNOWN	1" OR LESS	OVER 1" THRU 2"	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8"	SYSTEM TOTALS
STEEL	0	66455	985	151	0	0	67591
DUCTILE IRON	0	0	0	0	0	0	0
COPPER	0	0	0	0	0	0	0
CAST/WROUGHT IRON	0	0	0	0	0	0	0
PLASTIC PVC	0	0	0	0	0	0	0
PLASTIC PE	0	117241	939	21	1	0	118202
PLASTIC ABS	0	0	0	0	0	0	0
PLASTIC OTHER	0	0	0	0	0	0	0
OTHER	0	0	0	0	0	0	0
RECONDITIONED CAST IRON	0	0	0	0	0	0	0
TOTAL	0	183696	1924	172	1	0	185793
Describe Other Material:							

4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION

	UNKNOWN	PRE-1940	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-1999	2000-2009	2010-2019	TOTAL

MILES OF MAIN	0	24	85	281	706	423	539	1596	769	263	4686
NUMBER OF SERVICES	0	5381	8697	9260	39309	24388	14991	40125	30410	12953	185514

PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR

CAUSE OF LEAK	MAINS		SERVICES	
	TOTAL	HAZARDOUS	TOTAL	HAZARDOUS
CORROSION FAILURE	2	0	9	1
NATURAL FORCE DAMAGE	1	0	11	6
EXCAVATION DAMAGE	45	45	138	135
OTHER OUTSIDE FORCE DAMAGE	1	1	25	23
PIPE, WELD OR JOINT FAILURE	6	2	13	5
EQUIPMENT FAILURE	7	3	215	23
INCORRECT OPERATIONS	1	0	4	3
OTHER CAUSE	2	1	7	3

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR : 8

PART D - EXCAVATION DAMAGE

1. TOTAL NUMBER OF EXCAVATION DAMAGES BY APPARENT ROOT CAUSE: 218

a. One-Call Notification Practices Not Sufficient: 70

b. Locating Practices Not Sufficient: 51

c. Excavation Practices Not Sufficient: 93

d. Other: 4

2. NUMBER OF EXCAVATION TICKETS : 87200

PART E-EXCESS FLOW VALUE(EFV) DATA

NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 2393

ESTIMATED NUMBER OF EFV'S IN THE SYSTEM AT THE END OF YEAR: 14339

PART F - LEAKS ON FEDERAL LAND

TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 0

PART G-PERCENT OF UNACCOUNTED FOR GAS

UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.

INPUT FOR YEAR ENDING 6/30: 1.50%

PART H - ADDITIONAL INFORMATION

PART I - PREPARER

Devin Mccarthy,DOT Coordinator (Preparer's Name and Title)	(406)497-3218 (Area Code and Telephone Number)
devin.mccarthy@northwestern.com (Preparer's email address)	(406) 497-2048 (Area Code and Facsimile Number)

	A	B	C	D	E
1	**Historic MT Natural Distribution Expense**				
2	**By Activity 2012-2015**				
3					
4			Actual		
5		2012	2013	2014	2015
6	* Corrosion Control Maint-Mains	63,298	39,680	45,109	53,264
7	* Corrosion Control Maint-Services	46,602	162,294	35,771	20,189
8	* Gas Inside Meter Survey	43,402	85,072	32,994	42,402
9	* Gas Leak Survey 5 Year	320,098	334,007	398,834	379,248
10	* Gas Business District Survey	109,567	100,551	119,980	143,439
11	* Premise Inspection-Gas	758	34	370	484
12	* Zone Valve Maintenence	88,681	81,894	80,029	76,547
13	* Cased Crossing Maint & Repair	35,704	3,556	29,941	5,132
14	* Regulator Station Maint & Repair	87,160	100,324	77,551	78,929
15	* Regulator Station Inspection	203,192	202,938	222,510	209,529
16	** **MT Compliance Gas**	**998,462**	**1,110,349**	**1,043,090**	**1,009,162**
17	* NG Misc Jobbing Work	13,838	13,905	21,896	29,540
18	* NG Temp Services (Exp)	(429)			(1,360)
19	* Gas Odor Calls	921,929	862,294	857,998	763,861
20	* Gas Customer Investigation	460,626	495,943	440,371	399,112
21	* No Heat/Pilot Light Calls	706,810	722,395	717,487	595,970
22	* Gas Locates	863,997	971,260	975,955	1,033,227
23	* Gas Con/Discon Credit	100,959	87,376	110,300	120,012
24	* Gas Con/Discon Non-Credit	871,216	865,292	807,213	869,440
25	* Gas Relocations	16,779	8,083	10,989	2,455
26	* Natural Gas Damages	39,876	18,047	44,836	9,560
27	* Townsend Customer Gas	6,754	10,738	7,078	5,429
28	** **MT Customer Gas**	**4,002,356**	**4,055,332**	**3,994,124**	**3,827,248**
29	* Meter Move/Fire Valve	3,337	706	1,572	2,573
30	* Main Maintenance & Repair	204,538	279,939	238,659	192,854
31	* Short/Ground Repair-Services	778	1,004	3,819	720
32	* Mains & Services Operation	720,849	883,432	770,004	700,927
33	* Gas Meter Testing	22,382	31,507	8,000	2,414
34	* Gas Meter Calibration Inspect	73,822	64,622	89,471	88,015
35	* Service Maintenance & Repair	243,214	342,802	326,875	361,993
36	* Gas Risers in Concrete	7,888	1,919	170	552
37	* Townsend Proactive Gas	89,753	90,180	90,044	68,233
38	** **MT Proactive Gas**	**1,366,562**	**1,696,111**	**1,528,614**	**1,418,281**
39	* Gas Leak Repair-Mains	78,401	102,391	43,951	56,143
40	* Gas Leak Repair-Services	142,068	180,574	72,567	81,560
41	* Gas Meter Operation & Inspection	242,854	270,251	233,610	243,866
42	* Gas Meter Maintenance & Repair	672,176	651,170	879,730	829,518
43	** **MT Reactive Gas**	**1,135,500**	**1,204,387**	**1,229,858**	**1,211,087**
44	* Company Meetings Gas Craft	124,501	146,901	90,839	96,286
45	* Company Training Gas Craft	532,637	548,399	511,840	520,241
46	* Union Non-Productive Time	1,480,387	1,558,327	1,812,600	1,802,552
47	** **MT Non-Productive Time**	**2,137,526**	**2,253,627**	**2,415,279**	**2,419,079**
48	* Supv & Eng-Gas Operations	808,163	820,512	817,813	845,561
49	* Supv & Eng-Gas Maintenance	325,035	328,624	316,775	336,583
50	** **MT Supervision & Engineering**	**1,133,198**	**1,149,136**	**1,134,587**	**1,182,144**
51	*** **Total Field Operations**	**10,773,602**	**11,468,942**	**11,345,553**	**11,067,000**

	A	B	C	D	E
1	**Historic MT Natural Distribution Expense**				
2	**By Activity 2012-2015**				
52					
53					
54	**DSIP Expenses by Activity**				
55		**Actual**			
56		**2012**	**2013**	**2014**	**2015**
57	DSIP-Dist Integrity Mgmt Prog		28		
58	DSIP-Zone Valve Installation		36,262	17,962	
59	DSIP-Non-Business Inside Mtr		26,740	3,229	
60	DSIP-Gas Line Damage Preventi		243,953	468,648	618,761
61	DSIP-Gas Line Stub Removal		345		
62	DSIP-Farm Tap Rebuild		17,539		44,884
63	DSIP-Gas Main Repairs G1		961	2,884	1,686
64	DSIP-Gas Service Repairs G1		400,991	193,133	351
65	DSIP-Gas Meter Repair G1		69,489	13,688	
66	DSIP-Gas Amortization		603,346	603,346	603,346
67	**** Total DSIP Gas Expense**		**1,399,654**	**1,302,888**	**1,269,028**
68					
69	**Central Maintenance Gas Expense**				
70		**Actual**			
71		**2012**	**2013**	**2014**	**2015**
72	03PCOR874184 Corrosion Control Inspection	188,399	210,343	192,156	234,051
73	03PCOR874179 Short/Ground Survey	49,439	49,116	47,458	62,354
74	03PCOR874221 Rectifier Inspection	31,040	36,017	37,830	34,681
75	03PCOR874222 Cased Crossing Inspection	15,092	7,357	12,544	8,938
76	03PCOR874223 Separately Protected Inspections	18,075	3,131	4,647	2,145
77	03PCOR874224 Interference/Critical Bond Sur	2,039	2,474	2,167	1,824
78	03PCOR874225 Annual Potential Survey	68,297	71,164	71,992	57,110
79	03PCOR874226 Exposed Pipe Inspection	4,350	6,081	3,974	6,052
80	* Corrosion Control	376,731	385,684	372,767	407,156
81	40415 Gas System Intg-Supervision	603,695	606,365	752,332	740,316
82	40416 Corrosion Control Supervision	111,740	112,063	113,688	125,560
83	40462 Corrosion Control Fleet	35,904	29,423	35,956	29,602
84	* Corrosion Control Supervision	751,338	747,851	901,975	895,477
85	**** Corrosion Control**	**1,128,070**	**1,133,535**	**1,274,742**	**1,302,633**
86	07PMTR878162 Gas Meter Operation & Inspection	136,116	148,796	171,937	174,491
87	04SMTR885300 Supervision & Engineering-Gas			87	
88	07PMTR893365 Gas Meter Maintenenace & Repair	215,984	233,667	237,731	241,555
89	*** Meter Shop-Montana**	**352,100**	**382,464**	**409,754**	**416,046**
90	***** Total Central Maintenance Gas Expense**	**1,480,170**	**1,515,999**	**1,684,497**	**1,718,679**
91					
92	**Total Distribution Operations and Maintenance Expense**	**12,253,772**	**14,384,594**	**14,332,937**	**14,054,707**
93					

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF MICHAEL R. CASHELL

ON BEHALF OF NORTHWESTERN ENERGY

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Exhibits

Gas Transmission System Map	Exhibit__(MRC-1)
Letter to MPSC regarding NWE's Gas Storage System	Exhibit__(MRC-2)

Witness Information

Q. Please state your name and business address.

A. My name is Michael R. Cashell. I work at 11 East Park Street, Butte, Montana 59701.

Q. By whom are you employed and in what capacity?

A. I am NorthWestern Energy's ("NorthWestern") Vice President - Transmission.

Q. Please summarize your education and employment experience.

A. I graduated from the Montana Tech of the University of Montana in Butte, Montana, receiving a Bachelor of Science degree in Engineering Science in 1986. I also attended the University of Idaho's Public Utilities Executive Course in 1997. I have been certified as a North American Electric Reliability Corporation ("NERC") System Operator. I have worked in the electric and natural gas utility industry for over 30 years, employed first by the Montana Power Company ("MPC") and now by NorthWestern. My experience is primarily in the areas of gas and electric transmission system operations and maintenance, substation operations and maintenance, balancing authority area operation, tariff and contract administration, bulk power supply and operations, hydroelectric and thermal electric generation plant optimization, and independent power production.

1 **Q. What are your responsibilities as Vice President - Transmission?**

2 **A.** I am responsible for all aspects of NorthWestern's natural gas and electric
3 transmission systems and substations in Montana and South Dakota,
4 including the systems' safe, reliable and efficient operation, transmission
5 services, operations, planning, engineering, and maintenance. I am also
6 responsible for the activities related to transmission and transportation
7 contracts, interconnection agreements, and transmission service under
8 NorthWestern's Federal Energy Regulatory Commission ("FERC") Open
9 Access Transmission Tariff for our wholesale and unbundled retail
10 customers, procurement of ancillary services products, and compliance
11 activities related to all FERC regulation and NERC reliability and cyber
12 security standards. I am also responsible for all natural gas transportation
13 service under Montana Public Service Commission ("MPSC" or
14 "Commission") tariffs. Compliance requirements for which I am
15 responsible include all Department of Transportation, Pipeline Hazardous
16 Materials Safety Administration ("PHMSA"), and MPSC and South Dakota
17 Public Utilities Commission natural gas transmission and storage
18 regulation as well as Western Electricity Coordinating Council (in
19 Montana) and Midwest Reliability Organization criteria (in South Dakota),
20 both of which are NERC regional entities, and FERC criteria.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. Regarding NorthWestern's Montana natural gas transmission system, my testimony describes the major challenges and initiatives facing the system, operations and maintenance, compliance costs, and other expenses and capital expenditures since NorthWestern's last general gas rate case. The test year for the last rate case was 2011. As a result, I focus on the period 2012 through 2015. More specifically, my testimony discusses:

- the physical characteristics and operation of the system including gas transmission and storage facilities, major interconnections with other gas pipelines, and system deliverability;
- compliance responsibilities and activities including Pipeline Integrity Management ("PIM");
- operations and maintenance of the system;
- system expenses and capital investment including plant additions and major projects;
- gas transmission system planning; and
- a discussion of challenges to come including 1) on-going and new PHMSA compliance and other regulation, 2) meeting peak day capacity needs and system growth, and 3) meeting the potential future need to provide gas transmission service for gas-fired generation within NorthWestern's service territory.

1 **Description of the Natural Gas Transmission and Storage System**

2 **Q. Please provide an overview of NorthWestern's natural gas**

3 **transmission and storage system.**

4 **A.** NorthWestern's natural gas transmission system consists of more than

5 2,000 miles of pipeline and serves more than 153 city gate and meter

6 stations where pressure is reduced to distribution level and measured.

7 Pipeline diameter ranges from 1 inch through 24 inches. NorthWestern

8 provides service to approximately 189,400 customers located in 117

9 Montana communities as well as to several smaller natural gas distribution

10 companies that provide service to about 31,000 customers collectively.

11 There are 92 individual compression units totaling almost 80,000

12 horsepower dedicated to our Montana transmission, storage and

13 gathering operations. In addition, NorthWestern owns and operates a

14 pipeline which crosses into Canada through our wholly owned subsidiary,

15 Canadian-Montana Pipeline Company ("CMPL"). NorthWestern owns and

16 operates three working natural gas storage fields in Montana – Dry Creek

17 in southeast Montana with deliverability of about 44 million cubic feet per

18 day ("MMcfd"), Cobb Storage north of Cut Bank with deliverability of about

19 115 MMcfd, and Box Elder Storage near Havre with deliverability of about

20 5 MMcfd. This totals about 164 MMcfd of peak deliverability in the gas

21 storage system. There are 34 receipt points where gas enters our natural

22 gas transmission system. In our three active storage reservoirs, we cycle

about 10 billion cubic feet ("Bcf") in and out of storage annually. A system map is included as Exhibit__(MRC-1).

Q. When do peak deliverability needs on the transmission system occur?

A. Peak deliverability needs occur during the heating season – generally November through March. Typically, the colder the weather, the higher the daily deliverability need.

Q. What resources does the transmission system use to meet customer needs during the heating season?

A. The natural gas supply provided to our customers during the heating season comes from three main sources and the transmission and storage system is key to delivering this gas: 1) flowing gas, which is produced in Montana and has no other place to flow except onto NorthWestern's system; 2) interconnect gas, which is produced outside of Montana but is delivered under contracts with interconnected pipelines to supply gas to NorthWestern's system; and 3) storage gas, which is brought onto the system in the "off season" and injected into NorthWestern's storage fields for use during the heating season.

Nearly one-half of transmission system deliverability comes from our storage reservoirs' capability. NorthWestern also has interconnections

with five other major pipelines. These major connects include the TransCanada pipeline system at Carway northwest of Cut Bank via our CMPL subsidiary, Pine Cliff Energy northeast of Cut Bank at Aden, the TransGas system northeast of Havre (north flow only), Colorado Interstate Gas (Kinder Morgan), and WBI Energy in southeast Montana. These interconnections represent more than 39% of our peaking capability. The balance of our peak day requirements comes from gas produced within Montana (flowing gas) with interconnections to our system.

For the 2015/2016 heating season, the NorthWestern gas transmission system was designed to deliver 335 MMcfd, and this deliverability was achieved through the following resources:

	MMcfd	MMcfd	Resource
System Peak Design		335	Percentage
Transmission System Resources			
Flowing Gas		40	12%
Storage			
Cobb	115		
Dry Creek	44		
Box Elder	5		
Total Storage		164	49%
Interconnects			
South	20		
North	111		
Total Interconnects		131	39%
Total Transmission System Resources		335	

Q. What volume of natural gas did NorthWestern's transmission system deliver to customers in 2015?

A. NorthWestern delivered about 40.9 Bcf to our customers. About 43.5% or 17.8 Bcf of the gas was delivered to the core retail customers for which NorthWestern also has the responsibility to provide natural gas supply and 56.5% or 23.1 Bcf was delivered to the on-system, non-core customers – those customers to whom NorthWestern provides transmission service, but is not responsible for providing natural gas supply.

Transmission and Storage System Compliance

Q. Please summarize NorthWestern's natural gas transmission and storage system compliance responsibilities.

A. NorthWestern's gas transmission and storage system is regulated by PHMSA. PMHSA develops and enforces regulations for the safe, reliable, and environmentally sound operation of the nation's 2.6 million mile pipeline transportation system. The MPSC is responsible for review, audit and enforcement of PHMSA's rules and regulations applicable to NorthWestern's natural gas transmission system. PHMSA's Pipeline Safety Regulations Parts 191 and 192 prescribe minimum federal safety standards for:

- materials,
- pipeline and component design,
- welding and construction requirements for pipelines,
- customer meters, service regulators, and service lines,
- corrosion control,

- testing requirements and pressure uprating,
- operations and maintenance,
- personnel qualifications,
- pipeline integrity management, and
- pipeline control room management.

NorthWestern also constructs, operates, and maintains its facilities and equipment in accordance with applicable federal and state air, water, and waste rules and regulations resulting from the Montana Environmental Policy Act and National Environmental Policy Act. NorthWestern works closely with the Montana Department of Environmental Quality regarding air quality compliance at each of its compressor stations.

NorthWestern provides a safe workplace for employees by complying with standards, rules, and regulations issued under the Occupational Safety and Health Act and providing workplace conditions that conform to applicable Occupational Safety and Health Administration standards.

Pipeline Integrity Management

Q. Please explain PIM.

A. PHMSA regulations, which took effect in January 2004, require transmission operators to develop PIM programs for gas transmission pipelines located where a leak or rupture could do the most harm – in High

Consequence Areas ("HCAs"). The regulations require gas transmission pipeline operators to: 1) perform baseline assessments as well as ongoing assessments of pipeline integrity; 2) improve data collection, integration, and analysis; 3) repair and remediate the pipeline as necessary, and 4) implement preventive and mitigative actions. HCAs are areas within a calculated potential impact radius containing 20 or more buildings intended for human occupancy or identified sites. Identified sites are defined as follows:

1. An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12) month period (the days need not be consecutive). Examples included in the definition are beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility.
2. A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12) month period (the days and weeks need not be consecutive). Examples included in the definition are religious facilities, office buildings, community centers, general stores, 4–H facilities, and roller rinks.
3. A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples included in the definition are hospitals, prisons, schools, day-care facilities, retirement facilities and assisted-living facilities.

Q. What costs has NorthWestern incurred to comply with PIM?

A. Since the regulations took effect in 2004, NorthWestern has incurred over $25 million in capital costs and over $4.5 million in expense on PIM. From 2012 through 2015, NorthWestern spent about $7.6 million on PIM capital projects and incurred about $2.2 million in expense.

<u>Transmission and Storage System Operation and Maintenance</u>

Q. Please provide an overview of operation and maintenance activities on NorthWestern's Montana natural gas transmission system and storage facilities.

A. NorthWestern has approximately 120 full-time employees located in Butte, Augusta, Dry Creek, Cut Bank, Havre, and Deer Lodge who operate and maintain its natural gas transmission system and storage facilities. The staff provides engineering; maintenance of the Geographic Information System; design drafting; construction and maintenance; system integrity and cathodic protection; gas measurement; billing and supervisory control and data acquisition; gas system control; gas production, gathering, and processing; and storage and transmission services. The staff's responsibility includes the safe, reliable operation of the system including inspections.

Q. Please further describe NorthWestern's inspection and maintenance activities.

1 **A.** One hundred percent of the natural gas transmission system is inspected
2 annually through visual, laser detection, or flame ionization testing. Laser
3 technology and flame ionization are both techniques that can be used to
4 detect the level of flammable gas in an environment.
5
6 Depending on location and population, some portions of the system are
7 inspected more often. Known HCAs are patrolled monthly for any
8 changes. Other activity includes routine maintenance, compressor
9 overhauls, well maintenance, cathodic protection maintenance, and city
10 gate station maintenance. NorthWestern also uses contractors in some
11 cases to complete various tasks on our system including line clearance
12 and compressor overhauls.
13
14 **Q. What operation, inspection and maintenance activities does**
15 **NorthWestern conduct on its natural gas storage facilities?**
16 **A.** There has been national interest in the safety and inspection of natural
17 gas storage fields in recent months. Recently, NorthWestern provided a
18 letter to the MPSC to explain the operation, inspection, and maintenance
19 activities it conducts on its natural gas storage facilities. That letter is
20 included as Exhibit__(MRC-2).
21
22 **Transmission and Storage System Expenses**
23 **Q. What are NorthWestern's average annual transmission and storage**
24 **system expenses?**

A. The natural gas transmission and storage system expenses by major category for the last four years are listed in the table below. Overall expenses have averaged over $12 million from 2012 through 2015. Except for minor related costs incurred in 2015, this does not include the estimated expense of $6 million to $7 million that must be incurred over the next several years to complete the Integrity Verification Process. This process is discussed later in this testimony.

Gas Transmission Expense By Activity 2012-2015	Actual			
	2012	2013	2014	2015
** Gas Line Locates	321,009	299,833	240,874	268,808
** Compressor Sta Operation/Maintenance	1,230,248	2,024,257	1,754,768	1,855,054
** Gas Line Preventative Maintenance	983,817	1,384,599	1,492,627	1,125,416
** Gas Line Integrity Management	836,761	279,471	136,364	150,190
** Corrosion Control Inspection	50,792	65,479	71,357	39,697
** Corrosion Control Maintenance	333,870	321,225	317,137	330,521
** Meter/Regulator Station Maintenance	504,043	486,797	487,528	585,883
** City Gate Maintenance	433,498	494,048	506,904	407,132
** Purification Equipment Maintenance	166,528	164,828	119,721	153,040
** Dehydration Equipment Maintenance	19,079	27,860	20,990	6,699
** Meter Operation & Inspect	44,458	43,407	47,039	49,431
** Supervision & Engineering	3,524,757	3,731,932	3,883,424	3,893,275
** System Control Supervision	941,915	924,770	932,183	1,048,726
** Administrative Activity	354,717	490,594	477,968	470,761
** Miscellaneous Operation	467,044	375,094	398,578	223,500
*** **Gas Transmission**	**10,212,535**	**11,114,194**	**10,887,460**	**10,608,133**
** Compressor Sta Operation/Maintenance	367,692	363,202	785,186	488,324
** Storage Preventative Maintenance	122,165	67,176	109,733	81,130
** Storage Repair & Maintenance	38,844	41,920	48,300	79,689
** Corrosion Control Inspection	2,585	1,994	3,630	1,084
** Meter/Regulator Station Maintenance	36,867	23,440	41,338	67,211
** Gas Well Maintenance	235,823	252,637	312,043	402,718
** Purification Equipment Maintenance	101,045	118,715	183,238	120,498
** Supervision & Engineering	155,609	161,439	149,788	147,614
** Administrative Activity	7,852	7,765	9,136	11,292
** Miscellaneous Operation	87,965	92,347	99,906	70,804
*** **Gas Storage**	**1,156,445**	**1,130,636**	**1,742,299**	**1,470,364**
*** **Canadian Montana Pipeline**	**3,410**	**3,876**	**11,122**	**9,425**
**** **Total Expense**	**11,372,390**	**12,248,705**	**12,640,881**	**12,087,921**

**Note: an additional $769,092 of PIM Expense from 2012 - 2015 is in account "Supervision and Engineering"

1 **Transmission and Storage System Capital Expenditures**

2 **Q. Has NorthWestern made capital investments on its natural gas**
3 **transmission and storage system since 2011?**

4 **A.** Yes.

5

6 **Q. Please describe how plant values have changed since 2011.**

7 **A.** As of December 31, 2011, gas transmission original cost was
8 $246,454,553 and net book value was $156,968,875. On December 31,
9 2015, original cost was $270,949,811 and net book value was
10 $171,383,009. For gas storage, as of December 31, 2011, original cost
11 was $39,802,871 and net book value was $18,789,088. On December 31,
12 2015, original cost was $40,713,054 and net book value was $17,148,026.
13 From 2012 through 2015, NorthWestern invested $33.6 million in its gas
14 transmission and storage system. Depreciation during that same time
15 period was $17.3 million on the transmission system and $2.7 million on
16 the storage system, a total of $20.0 million. In summary, NorthWestern
17 invested in its natural gas transmission and storage system at a rate of
18 nearly 1.7 times depreciation during this time period.

19

20 **Q. In what areas did NorthWestern make these investments?**

21 **A.** The largest investment, over $13.2 million, was made in the Reliability-
22 Proactive category and includes many items such as upgrades to
23 compressor controllers and systems, repair of stream and river crossing

exposures, cathodic protection, line segment reroutes, and odorant system containment. Capital investments in PIM programs totaled nearly $7.6 million. The largest PIM-related expenditures have been replacing/rerouting line segments in HCAs. Investments totaling $1.9 million in the Reliability-Reactive category were primarily related to dealing with unanticipated events such as stream crossing exposures, seam leaks, equipment failure, leaking mechanical fittings, or third party damage in which correction could not be delayed. In addition, $3.3 million has been invested in the gas storage system primarily in compressor additions and replacements, enhancements to storage control systems, liquids removal equipment, storage leases, and other miscellaneous items. Finally, in the Major Projects category, investment totaled nearly $4.9 million during the period. Projects in this category included relocating a segment of pipeline in the Missoula-Rattlesnake area to move it away from an area very close to homes that were built after its installation. Another project was a significant addition to storage compression in our Cobb Storage field that was required in order to maintain peak day deliverability from that field. Finally, nearly $2.7 million of investment was made in other capital projects.

Gas Transmission and Storage System Planning

Q. Please describe NorthWestern's transmission and storage system planning methodology.

1 **A.** NorthWestern plans for modifications and upgrades to the gas
2 transmission and storage system to meet growing customer peak day
3 deliverability needs using hydraulic engineering modeling software. The
4 software is capable of determining pipeline pressure and size
5 requirements for the entire system. The model helps us to predict overall
6 system needs and peaking requirements which then allows us to
7 determine how to maintain or increase overall deliverability through on-
8 system gas, storage capability, and interconnections to other pipelines.
9 The modeling software also allows us to study and engineer for local area
10 deliverability under normal operation and peaking events.
11
12 Each year, a multi-variable, linear regression program is used to develop
13 the expected system peak day requirements based on expected adverse
14 weather conditions and use per customer. The variables include average
15 daily temperature, previous day temperature, next day temperature, wind
16 speed, relative humidity, cloud cover, weekday/weekend occurrence, and
17 percent residential customers. Of all of the variables, the model is the
18 most sensitive to the temperature of the peak day event. The peak day
19 design delivery capability for the system drives the capacity-related capital
20 expenditures on the gas transmission and storage system. As a result,
21 this effort is an important annual exercise and helps NorthWestern predict
22 capacity requirements and needed capital investment over a 15-year
23 planning horizon. Recently, NorthWestern worked with the National

1 Weather Service and the Montana Climate Office at the University of
2 Montana regarding its peak day forecasting techniques. We also
3 benchmarked against other similar gas delivery companies. This process
4 validated the methodology that we use for our forecasts and highlighted
5 the fact that the weather (temperature) that is assumed for the peak day is
6 the largest driver of all of the variables.
7
8 **Q. What happens if a contingency takes place and there is inadequate**
9 **deliverability to meet demand?**
10 **A.** While NorthWestern plans carefully and has built a certain amount of
11 redundancy into the gas compression system, we do recognize that
12 events out of our control can occur. These include much colder weather
13 than design or expected conditions (or for a longer period of time) or
14 unexpected equipment outages either on our system or on adjacent
15 systems delivering to our interconnections. As a result, beginning with the
16 2015-2016 heating season, NorthWestern developed a Gas Curtailment
17 Plan that would have allowed us to interrupt gas use through careful
18 curtailment of NorthWestern electric customers that also are served by
19 NorthWestern's natural gas system. For many years we have had
20 curtailment plans on the electric system that are part of our overall
21 planning and compliance requirements. It is prudent to also have a
22 curtailment plan for gas operations in order to avoid more prolonged,

difficult outages. We will continue to utilize this Gas Curtailment Plan going forward and update it as required.

Gas Transmission and Storage Challenges

Q. Are there any additional issues that you would like the Commission to be aware of regarding the current or future operation of the gas transmission and storage system?

A. Yes, there are two main items. The first involves several issues related to pipeline safety. In April 2016, PHMSA released a Notice of Proposed Rulemaking ("NOPR") which, if unchanged before it becomes law, could impose certain retroactive requirements for pipeline materials verification and establishment of maximum allowable operating pressure. It would also establish a new pipeline classification for Moderate Consequence Areas, which would carry many of the requirements that currently exist for HCAs. NorthWestern provided specific comments on this NOPR to PHMSA in July 2016 and also participated in developing and supported the comments submitted by the American Gas Association. Using information from our historic compliance with PIM regulations, NorthWestern has initially estimated that, over a 15-year period, compliance with the NOPR could require over $225 million in capital investment and over $28 million in additional expense.

A precursor to the PHMSA NOPR is the Integrity Verification Process ("IVP") mentioned above. This process, embodied in current PHMSA rules, requires NorthWestern to verify the Maximum Allowable Operating Pressure ("MAOP") and material properties for gas transmission lines, including pipelines constructed before 1970 that had previously been grandfathered from testing protocols. IVP requires reliable, verifiable, traceable, and complete records defined as:

- Reliable – suitable or fit to be relied on.
- Traceable – records that can be clearly linked to original pipeline information.
- Verifiable – records in which information is confirmed by other complementary, but separate, documentation.
- Complete – records that are finalized as evidenced by a signature, date or other appropriate marking.

The IVP requires rebuilding pipeline records from available paper documents; prioritizing pipelines contained within HCAs; indexing and scanning MAOP-critical paper records; capturing location and attributes from MAOP relevant records; identifying gaps in record coverage; completing a full survey of the alignment of the gas transmission system using GPS technology; defining a strategy for closing information gaps; and mitigating risks.

The IVP is required in order to comply with rules already in place. As mentioned above, NorthWestern has estimated the cost of implementing the IVP will be approximately $6-7 million, primarily in expense, over a multi-year period. The table below is an estimate of the costs that we would expect to incur in order to implement IVP and a representative spread of the costs over time.

	Item	Work	Year 1	Year 2	Year 3	Year 4	Year 5	Task Total
Contractor Work or Products	1	IVP - Record Scanning and Packaging	$0	$150,000	$150,000	$0	$0	**$300,000**
	2	IVP Data Mining and Records Analysis	$0	$220,500	$1,653,750	$551,250	$0	**$2,425,500**
	3	IVP - Software Package	$0	$253,660	$172,700	$0	$0	**$426,360**
	4	GPS Center Line	$325,000	$300,840	$1,628,660	$0	$0	**$2,254,500**
NWE Resources	5	Engineering	$100,000	$75,000	$162,500	$162,500	$162,500	**$662,500**
	6	Analyst	$0	$0	$75,000	$75,000	$50,000	**$200,000**
	7	Field Support	$22,500	$0	$22,500	$22,500	$0	**$67,500**
	8	Geographic Information Systems	$6,250	$0	$75,000	$120,750	$98,000	**$300,000**
	9	Business Technology Support	$0	$0	$15,750	$15,750	$0	**$31,500**
	10	Records Management Support	$43,750	$0	$21,875	$21,875	$0	**$87,500**
	11	Project Management	$13,125	$0	$13,125	$13,125	$13,125	**$52,500**
		Total	**$510,625**	**$1,000,000**	**$3,990,860**	**$982,750**	**$323,625**	**$6,807,860**
		Yearly Totals	**$510,625**	**$1,000,000**	**$3,990,860**	**$982,750**	**$323,625**	
		Sum Total	**$6,807,860**					

NorthWestern has just begun implementation, but as shown in the table, significant incremental expenditures must be made over the next several years. These incremental costs are in excess of the average annual expenses during the 2012-2015 period.

NorthWestern is bringing this issue to the Commission's attention as part of this filing because of the unique nature of these costs. They are significant, federally mandated costs that are lumpy and atypical to recovery as part of a general rate filing under the Commission's rules. As such, NorthWestern's ability to properly recover these costs in a

conventional fashion is constrained. It is important that we work with the Commission on an alternative mechanism to recover these federally mandated costs that are imposed on NorthWestern and its customers in a timely fashion.

Finally, PHMSA is presently developing safety regulations for natural gas storage sites. While we cannot currently estimate what impact this may have on our gas storage system, recent proposed rulemakings from PHMSA are clearly shifting regulations away from performance-based compliance to prescriptive methods. These storage regulations could have future operational and financial impacts.

Q. What is the second item?

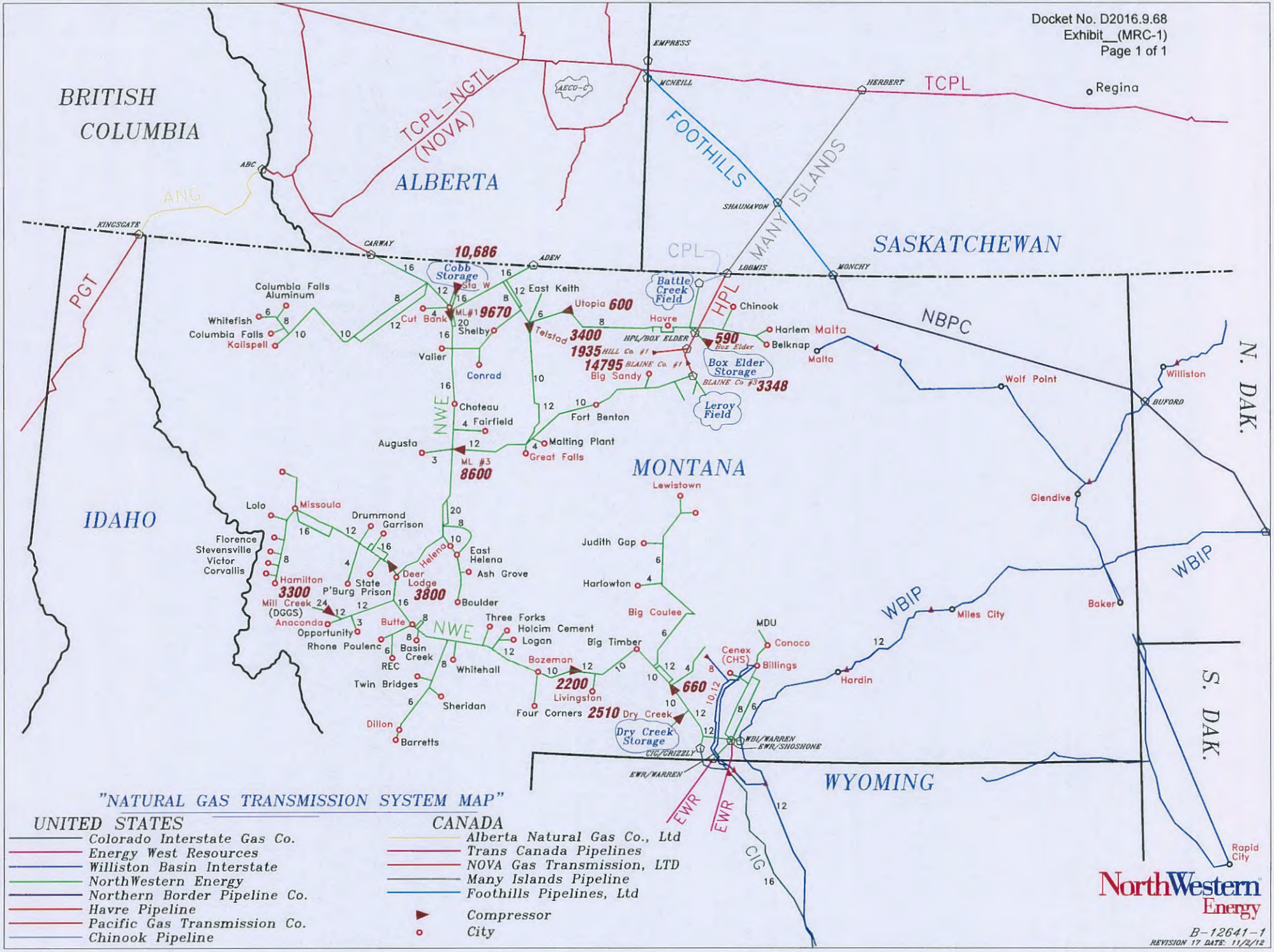
A. NorthWestern's ability to meet growing demands on our natural gas transmission and storage system is constrained in three ways: 1) Our system storage is physically limited to about 164 MMcfd of deliverability; 2) The deliverability of interconnections to adjacent pipelines and sources of gas is currently limited to about 135 MMcfd, and 3) On-system flowing gas deliverability is at about 40 MMcfd and is naturally depleting at a rate of about 10% per year. In addition, if NorthWestern adds new natural gas-fired generation as called for in its 2015 Electricity Supply Resource Procurement Plan, that generation will place further pressure on system deliverability needs.

As a result, NorthWestern is planning today for gas transmission upgrade requirements to meet the challenges ahead. The current overall transmission system deliverability limitations coupled with decreasing natural gas supply availability contributed to our need to develop the Gas Curtailment Plan discussed above.

We must consider our delivery system design as we continue to search for the best natural gas supply sources to meet our gas customers' needs. Accordingly, NorthWestern conducted a first phase study that has identified a number of options to increase gas transmission capacity including expansion of existing on-system storage, new on-system storage, and expanded interconnection capability. The top two options for expansion were 1) a Liquefied Natural Gas facility centrally located within our service territory and 2) expansion of our interconnection with Colorado Interstate Gas Pipeline. The initial high-level ten-year net present value investment estimates for these two options is about $85 to $95 million each.

Q. Does this conclude your testimony?

A. Yes, it does.


BRITISH COLUMBIA
ALBERTA
SASKATCHEWAN
MONTANA
IDAHO
WYOMING
N. DAK.
S. DAK.
TCPL-NGTL (NOVA)
AECO-C
TCPL
Regina
EMPRESS
MCNEILL
HERBERT
FOOTHILLS
MANY ISLANDS
SHAUNAVON
LOOMIS
MONCHY
ABC
KINGSGATE
CARWAY
ADEN
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CPL
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NBPC
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WBIP
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CIG
10,686
Cobb Storage
Sta. W
ML#1 9670
Cut Bank
Shelby
Valier
Conrad
Choteau
Fairfield
Augusta
ML #3 8600
Columbia Falls Aluminum
Whitefish
Columbia Falls
Kalispell
East Keith
Utopia 600
Telstad 3400
1935 HILL Co. #1
14795 BLAINE Co. #1
Big Sandy
Havre
HPL/BOX ELDER
Battle Creek Field
Chinook
Harlem
Belknap
Malta
590 Box Elder
Box Elder Storage
BLAINE Co #3 3348
Leroy Field
Fort Benton
Malting Plant
Great Falls
Wolf Point
Williston
BUFORD
Glendive
Baker
Miles City
Hardin
Lewistown
Judith Gap
Harlowton
Big Coulee
Big Timber
Bozeman
2200 Livingston
Four Corners
2510 Dry Creek
Dry Creek Storage
660
Cenex (CHS)
Billings
MDU
Conoco
WBI/WARREN
EWR/SHOSHONE
CIG/GRIZZLY
EWR/WARREN
Rapid City
Lolo
Missoula
Florence
Stevensville
Victor
Corvallis
Hamilton
3300
Mill Creek (DGGS)
Anaconda
Opportunity
Drummond
Garrison
Helena
Deer Lodge
3800
State P'Burg Prison
East Helena
Ash Grove
Boulder
Butte
Rhone Poulenc
Basin Creek
REC
Twin Bridges
Sheridan
Dillon
Barretts
Three Forks
Holcim Cement
Logan
Whitehall
"NATURAL GAS TRANSMISSION SYSTEM MAP"
UNITED STATES
Colorado Interstate Gas Co.
Energy West Resources
Williston Basin Interstate
NorthWestern Energy
Northern Border Pipeline Co.
Havre Pipeline
Pacific Gas Transmission Co.
Chinook Pipeline
CANADA
Alberta Natural Gas Co., Ltd
Trans Canada Pipelines
NOVA Gas Transmission, LTD
Many Islands Pipeline
Foothills Pipelines, Ltd
Compressor
City
NorthWestern Energy
B-12641-1
REVISION 17 DATE: 11/2/12

NorthWestern Energy
Delivering a Bright Future

July 14, 2016

Mr. Will Rosquist
Administrator, Regulatory Division
Montana Public Service Commission
PO Box 202601
Helena, MT 59620-2601

Re: Natural Gas Storage Field Operations

Dear Will:

As part of our on-going safety and reliability efforts on our Gas Storage and Transmission System, NorthWestern Energy ("NorthWestern") reviews its storage operations and procedures periodically and recently compared our storage system characteristics to those of Aliso Canyon in California. The result of our internal review is 1) we have good preventive maintenance and inspection measures in place; 2) the likelihood of an issue such as the Aliso Canyon situation occurring on our system is low; 3) NorthWestern's Natural Gas Storage System and characteristics differ significantly from those at Aliso Canyon; and 4) if a leak event were to occur, we have response plans in place including local support and well control responders with world-wide experience available through our insurance carrier.

Consistent with PHMSA recommendations and industry standards, NorthWestern has procedures and processes in place to prevent leaks as well as quickly detect leaks in either the Gas Transmission Pipeline System or the storage wells delivering gas to the piping system. We perform an annual pipeline patrol on all of our storage lines. This patrol is accomplished by personnel trained to perform such patrols, including leak detection, line locating, cathodic protection readings, and third-party activity awareness and damage prevention. Our employee operators are trained in detecting gas leaks and monitoring well performance. The operators are equipped with a personal lower explosive limit monitor during monthly inspections of well buildings and associated equipment. We check storage fields annually for signs of bacteria that could cause corrosion below the surface of the wells and in our piping systems and treat any wells that have bacteria detected with biocide. Importantly, all of NorthWestern's storage fields are in very rural locations, minimizing the potential impact of any issue on the public.

As part of our overall insurance coverage, we have access to Wild Well Control, Inc. ("Wild Well"). Specifically within the insurance policy, Wild Well is the company who assists in providing well control services and is a specialized well control company; giving us access to professional well control experts who have worked around the world. More information about Wild Well is available at its website, http://www.wildwell.com/

We did have an incident a number of years ago at the Cobb #2 well in Cobb Storage, which tested our procedures. A nipple broke on the wellhead, upstream of the casing valve. This well has about 600 psig at the surface on average. To repair the wellhead and stop the leaking gas, NorthWestern's engineering staff developed a procedure to safely remove the meter station from the wellhead by using self-contained breathing apparatus and using the local fire department to "fog" the area to prevent the

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possibility of accidental ignition in the area of the leak. This work was done on the surface at the well. A well control service was then brought in to pump fluid down the wellbore and "kill" the well. The broken nipple was replaced and the process was completed successfully.

Another potential failure in any well is a tubing failure, where the tubing would mechanically fail and drop to the bottom of the hole. If this were to occur, we would utilize our well service to pump fluid down the well hole, kill the well, and then retrieve the tubing from the well bore and replace the tubing.

If the casing was to fail and allow gas to migrate to the surface, the well service professionals would be utilized to kill the well by pumping fluid down the tubing and kill the well from the "bottom up". Once this was accomplished, we would determine the cause of the casing leak using a variety of well logs and develop a plan in conjunction with well service engineers to repair the casing or plug the well.

In any situation like those described above, our Emergency Manual describes how we respond. An immediate response by the local operating crew (Cut Bank, Dry Creek, or Havre) would secure the location, evaluate the situation, and notify our Gas Operations Center in Butte of the type of incident and response required. Gas Transmission Supervisors, in conjunction with the on-site field representatives, would decide on a course of action depending upon the situation encountered. This includes notifying local authorities, fire departments, potentially the Department of Emergency Services, the MPSC, NorthWestern Executive Management and Corporate Communications. Every field location is outfitted with proper emergency response equipment, such as self-contained breathing apparatus. As with our previous well response mentioned above, we would likely have the fire department on site to "fog" the area if we needed to use the self-contained breathing apparatus. There are also well service companies in the state who can respond quickly if we need to kill the well. Currently, under contract for well control services, we have a local company, Liquid Gold located in Sunburst, Montana. As noted already, none of our storage wells are in densely populated areas so securing the area will likely be much easier than situations in densely populated areas such as the Aliso Canyon instance.

For some comparison to the Aliso Canyon case, Aliso Canyon's field has about 100 wells and delivers 1.9 Billion Cubic Feet (BCF) per day. So each well would produce about 19 Million Cubic Feet per day (MMCF/d). Storage pressure is 3000 psi. The wells are 7,000 to 11,000 feet deep.

In contrast, NorthWestern's largest storage wells, in our Cobb Storage field, produce 6 to 7 MMcf/d with a pressure closer to 650 psi. Dry Creek Storage peaks at about 1200 psi, but the wells produce closer to 5 MMcf/d. These operating pressures and flows are much less than the operating pressure of the Aliso field. Thus, any potential leak in a NorthWestern field would have much different characteristics than the Aliso field.

NorthWestern Energy
Delivering a Bright Future

Mr. Rosquist
July 14, 2016
Page 3

From a geology standpoint, the Aliso field is, as noted, much larger, and likely with greater porosity and permeability than any of NorthWestern's fields. This means that the flow rates and pressures will be much greater than NorthWestern storage fields as noted above.

It is also important to note that the NorthWestern Natural Gas Storage System is a key strategic asset for meeting the needs of our customers. During peak operation, storage gas provides over a third of the supply needed to meet demand. As a result, it is critical to maintain the integrity of these facilities.

Will, if you, the Commissioners or Commission Staff have any further questions, please let me know.

Sincerely,

Michael R. Cashell
Vice President, Transmission
O 406-497-4575

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF

ADRIEN M. MCKENZIE, CFA

On behalf of

NORTHWESTERN ENERGY

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EXHIBIT:	**DESCRIPTION**
Exhibit__(AMM-1)	Qualifications of Adrien M. McKenzie
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Exhibit__(AMM-3)	Summary of Results
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Exhibit__(AMM-10)	Expected Earnings Approach
Exhibit__(AMM-11)	DCF Model - Non-Utility Group
Exhibit__(AMM-12)	Schedules Supporting ROE for Natural Gas Production Assets True Up

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, EMPLOYER, AND TITLE.

A1. My name is Adrien M. McKenzie. My business address is 3907 Red River Street, Austin, Texas, 78751. I am a Vice President of FINCAP, Inc.

Q2. PLEASE DESCRIBE YOUR QUALIFICATIONS AND PROFESSIONAL EXPERIENCE.

A2. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit__(AMM-1).

Q3. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A3. The purpose of my testimony is to present to the Montana Public Service Commission ("MPSC" or "Commission") my independent analysis of a forward-looking fair rate of return on equity ("ROE") for the Montana jurisdictional gas utility operations of NorthWestern Corporation, doing business as NorthWestern Energy ("NorthWestern" or "Company"). In addition, based on analyses using contemporaneous capital market data, I also evaluate a fair ROE for purposes of NorthWestern's Natural Gas Production Assets - True Up, as discussed in the Prefiled Direct Testimonies of Patrick J. DiFronzo and Daniel L. Rausch. Finally, I examine the reasonableness of the Company's requested capital structure, considering both the specific risks faced by NorthWestern and other industry guidelines.

Q4. PLEASE SUMMARIZE THE INFORMATION AND MATERIALS YOU RELIED ON TO SUPPORT THE OPINIONS AND CONCLUSIONS CONTAINED IN YOUR TESTIMONY.

A4. I am familiar with the organization, finances, and operations of NorthWestern from my participation in prior proceedings before the MPSC, the South Dakota Public Utilities Commission, and the Federal Energy Regulatory Commission ("FERC"). In

connection with the present filing, I considered and relied upon publicly available financial reports and filings, and other published information relating to NorthWestern. I also reviewed information relating generally to current capital market conditions and specifically to investor perceptions, requirements, and expectations for NorthWestern's gas utility operations. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for NorthWestern, and they form the basis of my analyses and conclusions.

Q5. HOW IS YOUR TESTIMONY ORGANIZED?

A5. After first presenting my conclusions and recommendations, I briefly review NorthWestern's operations and finances. I then examine current conditions in the capital markets and their implications in evaluating a fair return for NorthWestern. With this as a background, I discuss well-accepted quantitative analyses to estimate the current cost of equity for a separate reference group of natural gas utilities. These analyses included the discounted cash flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the empirical form of the Capital Asset Pricing Model ("ECAPM"), an equity risk premium approach based on allowed ROEs, and reference to expected earned rates of return for gas utilities. In addition, I discuss the issue of stock flotation expenses and the implications of these legitimate costs on the estimation of a reasonable ROE for the Company. Finally, I test my conclusions against an alternative check of reasonableness by applying the DCF model to a select group of low risk non-utility firms.

Based on the cost of equity estimates indicated by my analyses described above, I determined a fair ROE for NorthWestern's gas utility operations. My ROE evaluation takes into account the specific risks for the Company's jurisdictional utility operations and its requirements for financial strength. The final section of my

1 testimony presents the results of contemporaneous analyses supporting an ROE for use
2 in NorthWestern's Natural Gas Production Assets True Up.

3 **II. RETURN ON EQUITY FOR NORTHWESTERN**

4 **Q6. WHAT IS THE PURPOSE OF THIS SECTION?**

5 **A6.** This section presents my conclusions regarding a reasonable ROE applicable to
6 NorthWestern's gas utility operations. This section also discusses the relationship
7 between ROE and preservation of a utility's financial integrity and the ability to attract
8 capital. Finally, I discuss the reasonableness of the Company's capital structure
9 request in this case.

A. Importance of Financial Strength

10 **Q7. WHAT IS THE ROLE OF THE ROE IN SETTING A UTILITY'S RATES?**

11 **A7.** The ROE is the cost of attracting and retaining common equity investment in the
12 utility's physical plant and assets. This investment is necessary to finance the asset
13 base needed to provide utility service. Investors commit capital only if they expect to
14 earn a return on their investment commensurate with returns available from alternative
15 investments with comparable risks. Moreover, a fair and reasonable return on the
16 value of utility property is integral in meeting sound regulatory economics and the
17 standards set forth by the U.S. Supreme Court in the *Bluefield*[1] and *Hope*[2] cases. A
18 utility's allowed ROE should be sufficient to: 1) fairly compensate the utility's
19 investors, 2) enable the utility to offer a return adequate to attract new capital on
20 reasonable terms, and 3) maintain the utility's financial integrity. So long as the utility
21 has a reasonable opportunity to actually earn the allowed rate of return, these
22 standards should permit the utility to fulfill its obligation to provide reliable service

[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

while meeting the needs of customers through necessary system replacement and expansion, but they can only be met if the utility has a reasonable opportunity to actually earn its allowed ROE.

Q8. HOW DO THE MPSC'S ACTIONS IMPACT INVESTOR CONFIDENCE AND THEIR REQUIRED RATES OF RETURN?

A8. Regulatory signals are a major driver of investors' risk assessment for utilities. Security analysts study commission orders and regulatory policy statements to advise investors about where to put their money. If the Commission's actions instill confidence that the regulatory environment is supportive, investors make capital available to Montana utilities on more reasonable terms. When investors are confident that a utility has reasonable and balanced regulation, they will make funds available even in times of turmoil in the financial markets.

Q9. DOES NORTHWESTERN ANTICIPATE THE NEED FOR CAPITAL GOING FORWARD?

A9. Yes. NorthWestern will require capital investment to meet customer growth, provide for necessary maintenance and replacements of its natural gas utility systems, as well as fund new investment in electric generation, transmission and distribution facilities. Company-wide utility capital additions are expected to total approximately $1.2 billion through 2020. These planned capital additions are far from routine, given that NorthWestern's total rate base amounted to $3.4 billion at December 31, 2015. In Montana, NorthWestern has undertaken a multi-year effort to accelerate the replacement and modernization of its existing utility distribution system through its Distribution System Infrastructure Project ("DSIP"), which is discussed in the Prefiled Direct Testimony of Curt T. Pohl. From 2012 through 2015, NorthWestern invested approximately $24.0 million associated with the DSIP program, along with an additional $15.0 million to install new mains and services to connect new customers.

In addition, as Mr. Michael Cashell discusses in his testimony, the Company has made substantial investment in natural gas transmission and storage, with capital expenditures totaling approximately $33.6 million from 2012 through 2015. Apart from the need to meet deliverability requirements, NorthWestern estimates that compliance with pipeline safety requirements could result in over $225 million in additional capital expenditures. Continued support for NorthWestern's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

B. Implications of Regulatory Mechanisms

Q10. DID YOU CONSIDER THE IMPLICATIONS OF INDUSTRY INFRASTRUCTURE COST RECOVERY MECHANISMS IN EVALUATING A FAIR ROE FOR NORTHWESTERN?

A10. Yes. Adjustment mechanisms and cost trackers have been increasingly prevalent in the utility industry in recent years. In response to the increasing risk sensitivity of investors to uncertainty over fluctuations in costs and the importance of advancing other public interest goals such as reliability, energy conservation, and safety, utilities and their regulators have sought to mitigate some of the cost recovery uncertainty and align the interest of utilities and their customers through a variety of adjustment mechanisms. Based largely on the expanded use of ratemaking mechanisms to address operational risks and investment recovery, Moody's upgraded most regulated utilities in January 2014.[3] This is consistent with the view that investors perceive the impact of regulatory mechanisms to be an industry-wide factor. Just as a rising tide

[3] Moody's Investors Service, "US utility sector upgrades driven by stable and transparent regulatory frameworks," *Sector Comment* (Feb. 3, 2014).

lifts all boats, ratemaking mechanisms have had an across-the-board impact on risk perceptions for virtually all utilities.

Reflective of this trend, companies in the gas utility industry operate under a wide variety of cost adjustment mechanisms, in addition to the standard gas cost recovery clauses that they all have. These enhanced mechanisms range from riders to recover bad debt expense and post-retirement employee benefit costs to revenue decoupling and adjustment clauses designed to address rising capital investment outside of a traditional rate case and the impact of conservation programs. The majority of gas utilities benefit from revenue decoupling, along with a variety of other provisions that enhance their ability to recover operating and capital costs on a timely basis.[4] Similarly, Regulatory Research Associates concluded in its most recent review of adjustment clauses that, "some form of decoupling is in place in the vast majority of the jurisdictions."[5]

Q11. HAVE YOU SUMMARIZED THE VARIOUS REGULATORY MECHANISMS AVAILABLE TO OTHER GAS UTILITIES?

A11. Yes. Reflective of industry trends, the companies in the proxy group of gas utilities I used to estimate the cost of equity ("Gas Group") operate under a variety of regulatory adjustment mechanisms.[6] As summarized on Exhibit__(AMM-2), these mechanisms are ubiquitous and wide ranging. For example, six of the eight firms in the Gas Group have utilities that operate under some form of decoupling mechanism that accounts for the impact of various factors affecting sales volumes and revenues. In addition, Atmos

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[4] *See, e.g.,* American Gas Association, *Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: Current List* (Aug. 2016).

[5] Regulatory Research Associates, "Adjustment Clauses, A State-by-State Overview," *Regulatory Focus* (Aug. 22, 2016).

[6] Because this information is widely referenced by the investment community, it is also directly relevant to an evaluation of the risks and prospects that determine the cost of equity.

Energy Corporation has utilities that operate under enhanced rate design provisions, which have a similar impact.

Q12. DO THE COMPANY'S REGULATORY MECHANISMS SET NORTHWESTERN APART FROM OTHER FIRMS OPERATING IN THE UTILITY INDUSTRY?

A12. Yes. NorthWestern's gas utility operations in Montana currently operate under two expense trackers – one for its natural gas supply costs and one for a portion of changes in property taxes. These mechanisms are designed to recover cost changes on a timely basis, and as such, provide some means of reducing risk for the Company. However, as documented in Exhibit__(AMM-2), a far broader array of adjustment mechanisms are available to other gas utilities.

For example, unlike many gas utilities, NorthWestern does not have a weather normalization adjustment ("WNA") mechanism in place to account for the impacts of abnormal weather on its Montana-jurisdictional gas utility operations. A WNA moderates the impact of extreme weather on customers and, at the same time, dampens the volatility of a gas utility's revenues. Indeed, all of the eight gas utilities in the proxy group used to estimate the cost of equity have some form of weather mitigant, including decoupling mechanisms, adjustment clauses, insurance, and/or rate design features that make revenues less susceptible to variations in gas consumption due to weather. As the Value Line Investment Survey ("Value Line") noted:

> Weather is a factor that affects the demand for natural gas, especially from small commercial businesses and consumers. Not surprisingly, earnings for utilities are susceptible to seasonal temperature patterns, with consumption normally at its peak during the winter heating months. Unseasonably warm or cold weather can cause substantial volatility in quarterly operating results. But some companies strive to counteract this exposure through temperature-adjusted rate mechanisms, which are available in many states. Therefore, investors

> interested in utilities with more-stable profits from one year to the next are advised to look for companies that are able to hedge this risk.[7]

As a result, while the Company remains exposed to the risks associated with abnormal weather, the reduced uncertainties associated with weather mitigants are accounted-for by investors and reflected in my cost of equity estimates.

Q13. ARE THERE OTHER FACTORS THAT DISTINGUISH THE RISKS OF NORTHWESTERN'S GAS UTILITY OPERATIONS FROM OTHER GAS UTILITIES?

A13. Yes. In evaluating a reasonable rate of return on equity, it is also important to note that, unlike many gas utilities, NorthWestern does not benefit from elasticity or decoupling mechanisms that insulate utility margins from declining usage.[8] Similarly, with the repeal of the Lost Revenue Adjustment Mechanism ("LRAM") in 2015, NorthWestern is exposed to the impact of reduced sales volumes attributable to state-mandated energy conservation programs. Moody's noted that the decision to eliminate the LRAM was one factor that would "increase the uncertainty surrounding the degree of NWE's future cost recovery in Montana …"[9]

In addition, like other gas utilities, NorthWestern is committed to upgrading the reliability and safety of its gas distribution system through the DSIP. Unlike others in the industry, however, NorthWestern does not have the benefit of an infrastructure investment cost tracker or other regulatory mechanism that would allow for recovery of these costs outside a traditional rate case.

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[7] The Value Line Investment Survey at 541 (Jun. 3, 2016).
[8] With one exception, NorthWestern's 2015 gas loads fell below annual loads in every year since 2004.
[9] Moody's Investor Service, "NorthWestern Corporation," *Issuer Comment* (April 1, 2016).

Q14. WHAT DOES THIS IMPLY WITH RESPECT TO NORTHWESTERN'S RISKS RELATIVE TO OTHER GAS UTILITIES IN GENERAL?

A14. NorthWestern's continued exposure to the uncertainties associated with the impact of weather, price elasticity, and other fluctuations in customer usage implies a greater level of risk than is faced by other utilities, including the firms in my proxy group. Moody's observed that "NWE operates without some of the cost recovery features that we see in more supportive regulatory environments (e.g., forward test years, decoupling), which add cash flow predictability to the company's financial profile and help to improve, or offset, otherwise weak financial measures."[10] Because the gas utilities in my proxy group have the wide variety of regulatory mechanisms documented in Exhibit__(AMM-2), and NorthWestern's Montana gas operations do not, the ROE determined from my proxy group analysis is not directly applicable to NorthWestern. As the Washington Utilities and Transportation Commission recognized:

> Circumstances in the industry today and modern regulatory practice . . . have led to a proliferation of risk reducing mechanisms being in place for utilities throughout the United States. . . **The effects of these risk mitigating factors was by 2013, and is today, built into the data experts draw from the samples of companies they select as proxies.**[11]

In other words, the increased mitigation in risks associated with the proxy utilities' greater ability to adjust revenues and attenuate the risk of cost recovery is reflected in the cost of equity range determined from my proxy group analyses. To account for the higher level of risk associated with its relative lack of recovery mechanisms, a separate adjustment to NorthWestern's ROE is necessary.

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[10] Moody's Investors Service, "Rating Action: Moody's Changes Rating Outlook for NorthWestern Corporation to Negative from Stable; Ratings Affirmed," *Global Credit Research* (Jan. 22, 2016).

[11] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-130130 and UG-130138 (consolidated) et al., Order 15.14 at 69, ¶ 155 (June 29, 2015). Internal citations omitted (Emphasis added).

C. Implications of Attrition

1 **Q15. WHAT CAUSES ATTRITION?**

2 **A15.** Attrition is the deterioration of actual return below the allowed return that occurs when
3 the relationships between revenues, costs, and rate base used to establish rates do not
4 reflect the actual costs incurred to serve customers during the period that rates are in
5 effect. For example, if external factors are driving costs to increase more than
6 revenues, then the rate of return will fall short of the allowed return even if the utility
7 is operating efficiently. Similarly, when growth in the utility's investment outstrips the
8 rate base used for ratemaking, the earned rate of return will fall below the allowed
9 return through no fault of the utility's management. These imbalances are exacerbated
10 as the regulatory lag increases between the time when the data used to establish rates
11 is measured and the date when the rates go into effect.

12 **Q16. WHY IS IT NECESSARY TO ADDRESS THE IMPACT OF ATTRITION?**

13 **A16.** Investors are concerned with what they can expect in the future, not what they might
14 expect in theory if a historical test year were to repeat. To be fair to investors and to
15 benefit customers, a regulated utility must have an <u>opportunity to actually earn a</u>
16 <u>reasonable return</u> that will maintain financial integrity, facilitate capital attraction, and
17 compensate for risk. In other words, it is the end result in the future that determines
18 whether or not the *Hope* and *Bluefield* standards are met. Standard & Poor's
19 Corporation ("S&P") observed that its risk analysis focuses on the utility's ability to
20 consistently <u>earn</u> a reasonable return:

21 > Notably, the analysis does not revolve around "authorized" returns, but
22 > rather on actual earned returns. We note the many examples of utilities
23 > with healthy authorized returns that, we believe, have no meaningful
24 > expectation of actually earning that return because of rate case lag,
25 > expense disallowances, etc.[12]

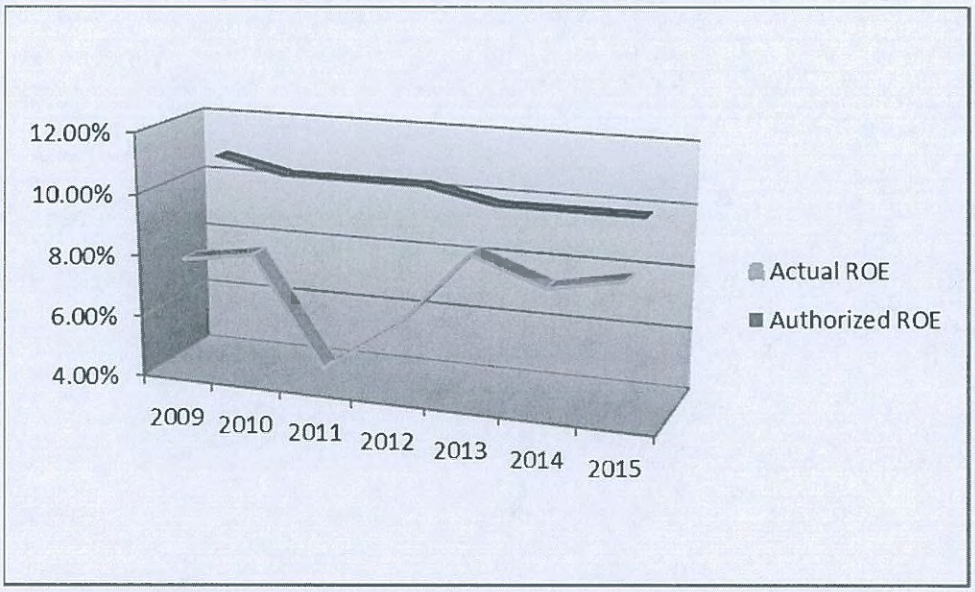
[12] Standard & Poor's Corporation, "Assessing U.S. Utility Regulatory Environments," RatingsDirect (Nov. 7, 2008).

Similarly, Moody's Investors Service ("Moody's) concluded, "we evaluate the framework and mechanisms that allow a utility to recover its costs and investments and earn allowed returns. We are less concerned with the official allowed return on equity, instead focusing on the earned returns and cash flows."[13] Absent other changes to the regulatory paradigm that allow the utility to better match its revenues with its costs, attrition warrants a higher authorized ROE in order to satisfy the end-result test of *Hope* and *Bluefield.*

Q17. HAS THE COMPANY EXPERIENCED ATTRITION AND REGULATORY LAG WITH RESPECT TO ITS MONTANA GAS UTILITY OPERATIONS?

A17. Yes. Regulatory lag and attrition have been consistent issues for NorthWestern, and the Company has been unable to earn its authorized ROE. Figure 1 below compares NorthWestern's actual earned ROE attributable to its jurisdictional gas utility operations with its authorized ROE over the 2009-2015 period:

FIGURE 1
ACTUAL VS. AUTHORIZED ROE



[13] Moody's Investors Service, "Electric Utilities Face Challenges Beyond Near-Term," *Industry Outlook* (Jan. 2010).

1 Fitch Ratings Ltd. observed that for NorthWestern, "regulatory lag due to the use of
2 historical test years remains a credit concern in a period of rising operating costs and
3 peaking capex over 2015-2017."[14]

4 **Q18. IS IT REASONABLE TO CONSIDER THE IMPACT OF NORTHWESTERN'S**
5 **EXPOSURE TO ATTRITION?**

6 **A18.** Yes. If the equity capital that is dedicated to utility public service does not have an
7 opportunity to earn a return commensurate with that available from alternatives of
8 equivalent risk in the capital markets, investors are not being adequately compensated
9 for the use of their money and bearing risk. Setting rates at a level that considers the
10 impact of attrition and allows the utility an opportunity to actually earn its authorized
11 ROE is consistent with fundamental regulatory principles. Central to the
12 determination of reasonable rates for utility service is the notion that owners of public
13 utility properties are protected from confiscation. The Supreme Court standards
14 dictate that the end result test must be applied to the actual returns that investors
15 expect if they put their money at risk to finance utilities.

16 This end result can only be achieved for NorthWestern if the allowed return is
17 sufficient to offset the impact of attrition. That end result would maintain the utility's
18 financial integrity, ability to attract capital and offer investors fair compensation for
19 the risk they bear. Attrition will result in under-earning the allowed ROE if the impact
20 of regulatory lag and rising capital requirements are ignored. Thus, whatever the
21 Commission ultimately determines to be investors' required return, the only way to
22 achieve that end result is to set the ROE at a higher level that is sufficient to give the
23 Company an opportunity to actually earn investors' required rate of return in the
24 future.

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[14] Fitch Ratings Ltd., "Fitch Affirms NorthWestern Corp.'s IDR at 'BBB+'; Outlook Stable," *Press Release* (Nov. 9, 2015).

D. Recommended ROE – Prospective Period

1 **Q19. PLEASE SUMMARIZE THE RESULTS OF THE QUANTITATIVE**

2 **ANALYSES ON WHICH YOUR CONCLUSIONS WERE BASED.**

3 **A19.** My ROE recommendations are based on the results of five methods – the DCF model,

4 the CAPM, the ECAPM, the risk premium approach, and the expected earnings

5 approach. The cost of common equity estimates produced by these analyses are

6 presented in Exhibit__(AMM-3), and summarized in Table 1, below:

TABLE 1
SUMMARY OF RESULTS
PROSPECTIVE ANALYSES

	Average	Midpoint
DCF		
Value Line	9.7%	9.9%
IBES	9.0%	9.0%
Zacks	8.6%	8.7%
Internal br + sv	9.1%	10.2%
CAPM		
Historical Bond Yield	10.4%	10.5%
Projected Bond Yield	10.7%	10.8%
Empirical CAPM		
Historical Bond Yield	11.0%	11.1%
Projected Bond Yield	11.3%	11.4%
Utility Risk Premium		
Current Bond Yields	10.4%	
Projected Bond Yields	11.2%	
Expected Earnings	11.3%	11.7%
Cost of Equity Recommendation		
Cost of Equity Range	**9.5% -- 10.7%**	
Midpoint	**10.1%**	
Risk Adjustment	**0.25%**	
Recommended ROE	**10.35%**	

Q20. WHAT ARE YOUR FINDINGS REGARDING THE FAIR ROE FOR NORTHWESTERN?

A20. Based on the results of my analyses and the economic requirements necessary to support continuous access to capital under reasonable terms, I recommend an ROE of 10.35% for NorthWestern's gas utility operations. The bases for my conclusion are summarized below:

- In order to reflect the risks and prospects associated with NorthWestern's Montana gas utility business, my analyses focused on a proxy group of gas utility firms;
- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied the DCF, CAPM, ECAPM, risk premium, and expected earnings methods to estimate a fair ROE for NorthWestern;
- Widespread expectations for higher interest rates emphasize the need to consider the impact of projected bond yields in evaluating the results of these quantitative methods;
- Based on the results of these analyses, and giving less weight to extremes at the high and low ends of the range, I concluded that the ROE for a regulated gas utility is in the 9.5% to 10.7% range, with a midpoint estimate of 10.1%; and,
- While flotation costs are legitimate business expenses of the Company, I did not add a specific adjustment to my recommended ROE to account for them. This treatment further supports the reasonableness of my 10.1% midpoint value.

Q21. IS AN ROE ADJUSTMENT WARRANTED DUE TO ATTRITION AND THE RELATIVE LACK OF REGULATORY MECHANISMS FOR NORTHWESTERN'S MONTANA GAS OPERATIONS?

A21. Yes. In evaluating a fair ROE for the Company's gas utility operations, the Commission should consider the economic reality that NorthWestern's actual returns have fallen systematically short of the allowed ROE and that, unlike most gas utilities, NorthWestern does not benefit from regulatory mechanisms that provide for timely recovery of fixed costs as customer usage changes. I concluded that:

- Setting rates at a level that considers the impact of attrition and allows the utility an opportunity to actually earn its authorized ROE is consistent with fundamental regulatory principles;
- To be fair to investors and to benefit customers, a regulated utility must have an opportunity to actually earn a return that will maintain financial integrity, facilitate capital attraction, and compensate for risk;
- The opportunity to actually earn a fair ROE and mitigate exposure to attrition is an important objective, and NorthWestern's gas utility operations in Montana have been chronically unable to earn the authorized rate of return;
- The Company operates with a considerably narrower range of regulatory adjustment mechanisms than exist for the utilities in my proxy group, which makes NorthWestern's gas operations in Montana relatively more risky; and,
- Considering NorthWestern's greater risks relative to the proxy group, its relative lack of regulatory adjustment mechanisms, and to address the impact of attrition and regulatory lag, I recommend an upward adjustment to the cost of equity.

Q22. WHAT ADJUSTMENT DO YOU RECOMMEND TO ACCOUNT FOR THESE FACTORS?

A22. In order to account for NorthWestern's greater relative risks, its lack of comparable regulatory mechanisms, and the Company's ongoing exposure to attrition and regulatory lag, I recommend an upward adjustment of 25 basis points to my proxy group results. In arriving at this adjustment, I referenced the observable risk premiums implied by utility bond yields, with yield spreads between bonds rated Baa and A currently amounting to approximately 90 basis points. In addition, prior to the widespread approval of decoupling mechanisms, some regulators concluded that implementing decoupling translated into reduced risk and warranted a lower ROE, with adjustments ranging from 10 to 50 basis points.[15] The corollary would hold that NorthWestern's lack of comparable regulatory mechanisms relative to the proxy group

[15] Morgan, Pamela, "A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations," *Graceful Systems, LLC* (March 2013) at 14.

would warrant a similar upward adjustment to the ROE. Considering these factors, and the need to recognize the Company's past inability to actually earn its allowed ROE, I added a conservative adjustment of 25 basis points to the 10.1% midpoint for the proxy group, resulting in my recommended ROE for NorthWestern of 10.35%.

Q23. IS THIS CONCLUSION SUPPORTED BY THE DCF RESULTS FOR YOUR SELECT GROUP OF NON-UTILITY FIRMS?

A23. Yes. Average DCF estimates for a low-risk group of firms in the competitive sector of the economy ranged from 10.3% to 10.6%, and averaged 10.5%. Objective indicators of investment risk indicate that these non-utility firms are less risky than the Company, and considering these results confirms that my recommended ROE for NorthWestern is within a reasonable range.

E. Recommended ROE – True Up Period

Q24. WHAT WERE THE RESULTS OF YOUR EVALUATION OF A FAIR ROE IN CONNECTION WITH NORTHWESTERN'S NATURAL GAS PRODUCTION ASSETS TRUE UP?

A24. Based on the results of identical qualitative analyses, but applied using contemporaneous data, I recommend an ROE of 10.65% for purposes of NorthWestern's Natural Gas Production Assets True Up. The findings supporting this conclusion are presented in Exhibit__(AMM-12) and summarized in Table 2, below:

TABLE 2
SUMMARY OF RESULTS
TRUE UP ANALYSES

	Average	Midpoint
DCF		
Value Line	10.4%	10.9%
IBES	9.9%	10.4%
Zacks	9.1%	9.5%
Internal br + sv	9.5%	10.2%
CAPM		
Historical Bond Yield	11.8%	11.8%
Projected Bond Yield	12.1%	12.1%
Empirical CAPM		
Historical Bond Yield	12.3%	12.3%
Projected Bond Yield	12.5%	12.4%
Utility Risk Premium		
Current Bond Yields	10.1%	
Projected Bond Yields	11.0%	
Expected Earnings	11.4%	12.5%
Cost of Equity Recommendation		
Cost of Equity Range	**9.8% -- 11.0%**	
Midpoint	**10.4%**	
Risk Adjustment	**0.25%**	
Recommended ROE	**10.65%**	

As illustrated above, considering these results, and giving less weight to extremes at the high and low ends of the range, I concluded that a contemporaneous ROE at mid-2014 for a regulated gas utility would fall in the 9.8% to 11.0% range, with a midpoint estimate of 10.4%.

Considering NorthWestern's higher risks relative to the proxy group, its lack of comparable adjustment mechanisms,[16] and attrition that was ongoing over the period covered by the True Up, an upward adjustment to the Company's cost of equity of 25 basis points is warranted. After adding a conservative adjustment of 25 basis points to the 10.4% cost of equity midpoint for the proxy group to account for NorthWestern's

[16] As discussed later in my testimony, while the LRAM was in effect through November 2015, the utilities in the proxy group nevertheless operated under a considerably broader range of regulatory adjustment mechanisms.

higher risk relative to the proxy group, its lack of comparable adjustment mechanisms, and attrition that was ongoing over the relevant period, my recommended ROE for the Company is 10.65% for purposes of the Natural Gas Production Assets True Up.

F. Other Factors

Q25. WHAT OTHER FACTORS SHOULD BE CONSIDERED IN EVALUATING A FAIR ROE FOR NORTHWESTERN IN THIS CASE?

A25. Apart from the results of the quantitative methods summarized above, it is crucial to recognize the importance of supporting the Company's financial position so that NorthWestern remains prepared to respond to unforeseen events that may materialize in the future. Recent challenges in the economic and financial market environment highlight the imperative of maintaining the Company's financial strength in order to attract the capital needed to secure reliable service at a lower cost for customers. The reasonableness of the Company's requested ROE is reinforced by the fact that, due to broad-based expectations for higher bond yields, current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond.

Q26. WHAT IS YOUR CONCLUSION AS TO THE REASONABLENESS OF NORTHWESTERN'S CAPITAL STRUCTURE?

A26. Based on my evaluation, I concluded that the Company's requested common equity ratio of 46.79% represents a reasonable capitalization. This conclusion was based on the following findings:

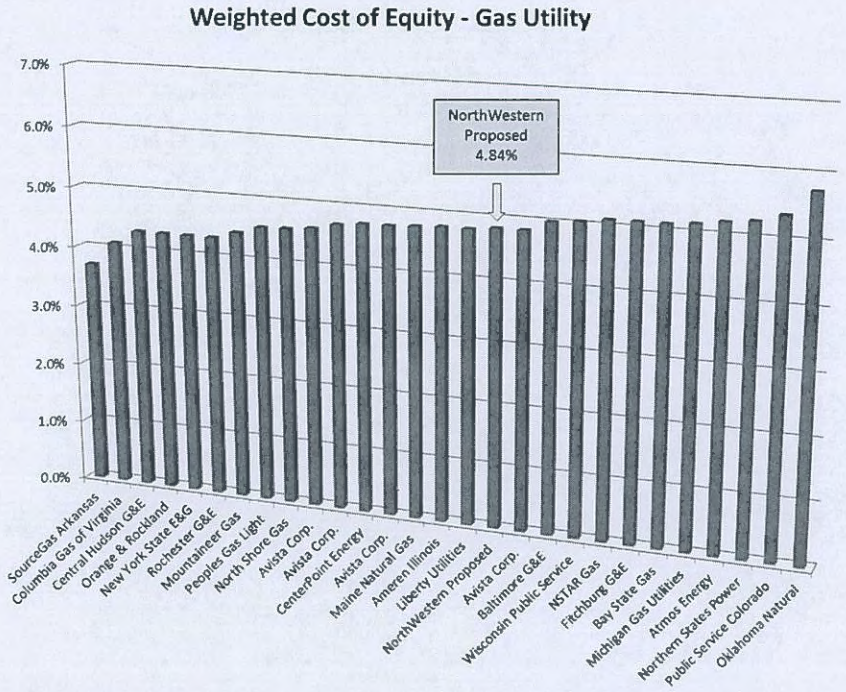
- NorthWestern's 46.79% common equity ratio falls well below the 55.1% average for the proxy group of gas utilities at year-end 2015. Similarly, NorthWestern's requested equity ratio falls well short of the 55.4% equity ratio based on Value Line's expectations for these utilities over the near-term. Because a capitalization that contains relatively less equity (and more debt) implies greater financial risk, it also implies a higher required rate of return to compensate investors for bearing additional uncertainty; and,

- NorthWestern's requested capitalization is consistent with the Company's need to maintain its credit standing and financial flexibility as it seeks to raise additional capital to fund significant system investments and meet the requirements of its service territory.

Q27. HOW DOES NORTHWESTERN'S REQUESTED 4.84% WEIGHTED COST OF EQUITY COMPARE WITH THE WEIGHTED COSTS OF EQUITY APPROVED FOR NATURAL GAS UTILITIES IN OTHER JURISDICTIONS?

A27. The bar chart below shows the weighted costs of equity approved by state regulators for investor-owned natural gas utilities across the country for the period January 1, 2015 through June 30, 2016. These observations represent all of the commission decisions that specify an ROE and an equity ratio for gas utilities during this period:

FIGURE 2



Source: Regulatory Research Associates, "Major Rate Case Decisions," *Regulatory Focus* (Jan. 14, 2016 & July 15, 2016).
Authorized Return on Equity * Common Equity/Total Cap. Excludes decisions where a data element was not disclosed.

1 Despite the Company's greater risks, NorthWestern's proposed weighted cost of equity
2 of 4.84% percent, which is also shown in the chart above, falls well within the
3 distribution of these weighted costs of equity for other gas utilities.

4 **Q28. WHAT ARE THE IMPLICATIONS OF SETTING AN ALLOWED ROE**
5 **BELOW THE RETURNS AVAILABLE FROM OTHER INVESTMENTS OF**
6 **COMPARABLE RISK?**

7 **A28.** If the utility is unable to offer a return similar to the returns available from other
8 opportunities of comparable risk, investors will become unwilling to supply capital to
9 the utility on reasonable terms. For existing investors, denying the utility an
10 opportunity to earn what is available from other similar risk alternatives prevents them
11 from earning their cost of capital. Both of these outcomes violate long recognized
12 regulatory standards and will ultimately harm both investors and customers.

13 **III. FUNDAMENTAL ANALYSES**

14 **Q29. WHAT IS THE PURPOSE OF THIS SECTION?**

15 **A29.** As a predicate to subsequent quantitative analyses, this section briefly reviews the
16 operations and finances of NorthWestern. In addition, it examines conditions in the
17 capital markets and the general economy. An understanding of the fundamental
18 factors driving the risks and prospects of natural gas utilities is essential in developing
19 an informed opinion of investors' expectations and requirements that are the basis of a
20 fair and reasonable ROE.

A. NorthWestern Energy

21 **Q30. BRIEFLY DESCRIBE NORTHWESTERN AND ITS MONTANA GAS**
22 **UTILITY OPERATIONS.**

23 **A30.** NorthWestern provides electricity and natural gas to approximately 701,000 customers
24 in Montana, South Dakota and Nebraska. The regulated natural gas utility business in

Montana includes production, storage, transmission and distribution. Natural gas is distributed to approximately 189,400 customers in 117 Montana communities over a system of approximately 5,000 miles of underground distribution pipelines. The natural gas transmission system consists of more than 2,000 miles of pipeline. Natural gas is used for residential and commercial heating, and for fuel for two electric generating facilities. Since 2010, the Company has acquired gas production and gathering systems as a part of an overall strategy to provide rate stability and customer value through the addition of regulated gas supply assets that are not subject to market forces.

For 2015, approximately 66% of the Company's Montana gas operation revenues and throughput were attributable to residential customers with commercial customers making up the remaining balance. At year-end 2015, the total rate base attributable to NorthWestern's Montana gas operations was $463.2 million, with total annual revenues of approximately $176.4 million.[17]

Q31. WHERE WAS THE CAPITAL USED TO FINANCE NORTHWESTERN'S INVESTMENT IN ITS MONTANA GAS UTILITY PLANT OBTAINED?

A31. As a wholly-owned division, the Montana gas operation has no publicly traded common stock and obtains common equity capital through NorthWestern Corporation, and through retained earnings. Long-term debt is also obtained through NorthWestern Corporation. NorthWestern Corporation has been assigned a corporate credit rating of "BBB" by S&P and a long-term issuer rating of "A3" (with Negative outlook) by Moody's.

[17] 2015 Annual Report of NorthWestern Energy to the Public Service Commission State of Montana (Gas Utility) at Schedules 8 and 27.

B. Outlook for Capital Costs

1 **Q32. WHAT ARE THE IMPLICATIONS OF CURRENT CAPITAL MARKET**
2 **CONDITIONS IN EVALUATING A FAIR ROE?**

3 **A32.** Current capital market conditions continue to be deeply affected by the Federal
4 Reserve's unprecedented monetary policy actions, which were designed to push
5 interest rates to historically and artificially low levels in an effort to stimulate the
6 economy and bolster employment. Since the Great Recession, investors have also had
7 to contend with a heightened level of economic uncertainty. The ongoing potential for
8 renewed turmoil in the capital markets has been seen repeatedly and investors have
9 reacted to such periods of "risk off" behavior by seeking a safe haven in U.S.
10 government bonds. As a result of this "flight to safety," Treasury bond yields have
11 been pushed significantly lower in the face of political, economic, and capital market
12 risks. While serving as President of the Federal Reserve Bank of Philadelphia,
13 Charles Plosser observed that U.S. interest rates were unprecedentedly low, and
14 "outside historical norms."[18]

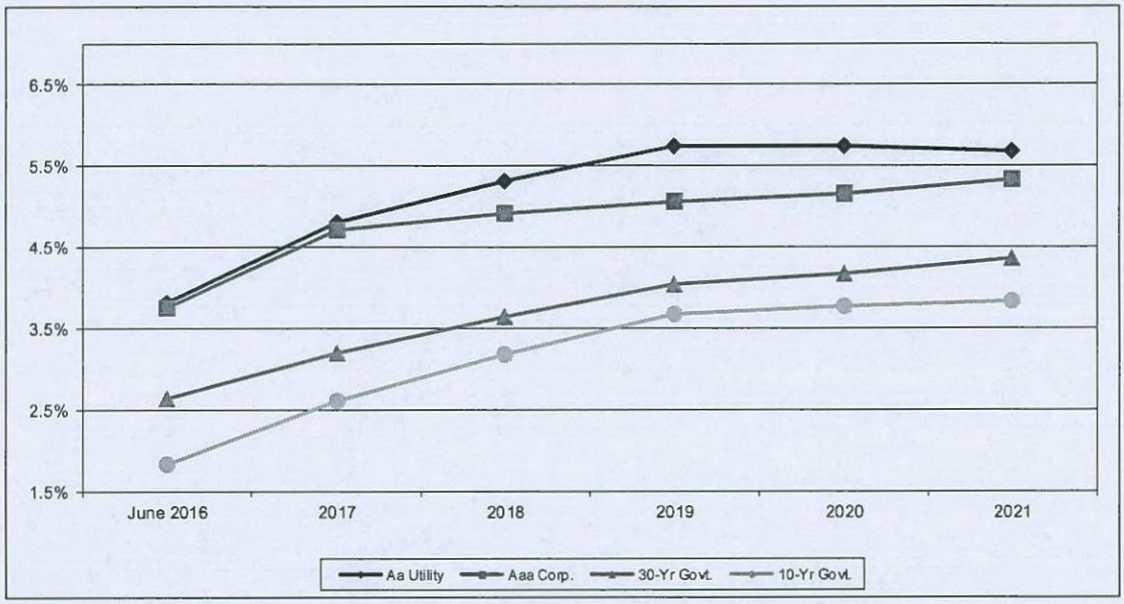
15 **Q33. ARE THESE VERY LOW INTEREST RATES EXPECTED TO CONTINUE?**

16 **A33.** No. Investors continue to anticipate that interest rates will increase significantly from
17 present levels. For example, the June 3, 2016 quarterly economic review from the
18 Value Line Investment Survey ("Value Line") anticipates that corporate bond yields
19 will increase 140 basis points between then and 2018. Figure 3 below compares
20 current interest rates on 10-year and 30-year Treasury bonds, triple-A rated corporate
21 bonds, and double-A rated utility bonds with the respective near-term projections from
22 Value Line, IHS Global Insight, Blue Chip Financial Forecasts ("Blue Chip"), and the

[18] Barnato, Katy, "Fed's Plosser: Low rates 'should make us nervous'," CNBC (Nov. 11, 2014). The average yield on 10-year Treasury bonds for the six-months ended June 2016 was 1.8%, which is even lower than the 2.3% yields prevailing at the time of Mr. Plosser's observations.

1 Energy Information Administration ("EIA"), which are sources that are highly
2 regarded and widely referenced:

FIGURE 3
INTEREST RATE TRENDS



Source:
Value Line Investment Survey, Forecast for the U.S. Economy (Jun. 3, 2016)
IHS Global Insight (Apr. 6 & Jun. 27, 2016)
Energy Information Administration, Annual Energy Outlook 2016 Early Release (May 17, 2016)
Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 35, No. 6 (Jun. 1, 2016)

3 As evidenced above, projections by investment advisors, forecasting services, and
4 government agencies support the general consensus in the investment community that
5 the present artificial low level of long-term interest rates will not be sustained.

6 **Q34. DOES THE FEDERAL RESERVE'S DECEMBER 16, 2015 DECISION TO**
7 **RAISE THE TARGET RANGE FOR THE FEDERAL FUNDS RATE BY ONE-**
8 **QUARTER PERCENTAGE POINT ALTER THESE CONDITIONS?**

9 **A34.** No. The Federal Reserve's long-anticipated move to increase the federal funds rate
10 represents a first, and very modest, step towards implementing the process of

monetary policy normalization outlined in its September 17, 2014 press release.[19] While the Federal Reserve's action marks the onset of the normalization process, this first move does not result in a fundamental alteration of its highly accommodative monetary policy. Nor does it remove uncertainty over the trajectory of further interest rate increases or the overhanging implications of the Federal Reserve's enormous holdings of long-term securities.

The Federal Reserve continues to exert considerable influence over capital market conditions through its massive holdings of Treasuries and mortgage-backed securities. Prior to the initiation of the stimulus program in 2009, the Federal Reserve's holdings of U.S. Treasury bonds and notes amounted to approximately $400-$500 billion. With the implementation of its asset purchase program, balances of Treasury securities and mortgage backed instruments climbed steadily, and their effect on capital market conditions became more pronounced. Table 2 below charts the course of the Federal Reserve's asset purchase program:

TABLE 2
FEDERAL RESERVE BALANCES OF
TREASURY BONDS AND MORTGAGE-BACKED SECURITIES
(BILLION $)

2008	$ 410
2009	$ 1,618
2010	$ 1,939
2011	$ 2,423
2012	$ 2,512
2013	$ 3,597
2014	$ 4,097
2015	$ 4,100

[19] Press Release, Fed. Reserve Sys., Policy Normalization Principles and Plans, (Sept. 17, 2014), http://www.federalreserve.gov/newsevents/press/monetary/20140917c.htm.

Far from representing a return to normal, the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities now amount to more than $4 trillion,[20] which is an all-time high. The Federal Reserve has announced its intention to maintain these balances by reinvesting principal payments from these securities "until normalization of the level of the federal funds rate is well under way."[21]

Of course, the corollary to these observations is that changes to this policy of reinvestment would further reduce stimulus measures and could place significant upward pressure on bond yields, especially considering the unprecedented magnitude of the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities. As a *Financial Analysts Journal* article noted:

> Because no precedent exists for the massive monetary easing that has been practiced over the past five years in the United States and Europe, the uncertainty surrounding the outcome of central bank policy is so vast. . . . Total assets on the balance sheets of most developed nations' central banks have grown massively since 2008, and the timing of when the banks will unwind those positions is uncertain.[22]

With expectations for higher interest rates, concerns about the implications of Britain's departure from the European Union, stagnating growth in China's economy, and fears of a global economic slowdown, coupled with dramatic decreases in oil and commodities prices, ongoing concerns over political stalemate in Washington, and political and economic unrest in the Middle East, the potential for significant volatility and higher capital costs is clearly evident to investors.

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[20] Federal Reserve Statistical Release, "Factors Affecting Reserve Balances of Depository Institutions and Condition Statement of Federal Reserve Banks," H.4.1.
[21] Federal Reserve, Federal Open Market Committee Press Release (June 15, 2016), https://www.federalreserve.gov/newsevents/press/monetary/20160615a.htm.
[22] Poole, William, "Prospects for and Ramifications of the Great Central Banking Unwind," Financial Analysts Journal (November/December 2013).

Q35. WHAT DO THESE EVENTS IMPLY WITH RESPECT TO THE ROE FOR NORTHWESTERN MORE GENERALLY?

A35. Current capital market conditions continue to reflect the impact of unprecedented policy measures taken in response to recent dislocations in the economy and financial markets. As a result, current capital costs are not representative of what is likely to prevail over the near-term future. As FERC concluded:

> [W]e also understand that any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula, including those produced by historically anomalous capital market conditions. Therefore, while the DCF model remains the Commission's preferred approach to determining allowed rate of return, the Commission may consider the extent to which economic anomalies may have affected the reliability of DCF analyses ...[23]

This conclusion continues to be supported by comparisons of current conditions to the historical record and independent forecasts. As demonstrated above, recognized economic forecasting services project that long-term capital costs will increase from present levels.

Thus, while the DCF model is a recognized approach to estimating the ROE, it is not without shortcomings and does not otherwise eliminate the need to ensure that the "end result" is fair. The Indiana Utility Regulatory Commission has recognized this principle:

> There are three principal reasons for our unwillingness to place a great deal of weight on the results of any DCF analysis. One is . . . the failure of the DCF model to conform to reality. The second is the undeniable fact that rarely if ever do two expert witnesses agree on the terms of a DCF equation for the same utility – for example, as we shall see in more detail below, projections of future dividend cash flow and anticipated price appreciation of the stock can vary widely. And, the third reason is that the unadjusted DCF result is almost always well below what any informed financial analysis would regard as defensible,

[23] Opinion No. 531, 147 FERC ¶ 61,234 at P 41 (2014).

> and therefore require an upward adjustment based largely on the expert witness's judgment. In these circumstances, we find it difficult to regard the results of a DCF computation as any more than suggestive.[24]

Given investors' expectations for rising interest rates and capital costs, the Commission should consider near-term forecasts for higher public utility bond yields in assessing the reasonableness of individual cost of equity estimates and in evaluating the ROE for NorthWestern. The use of these near-term forecasts for public utility bond yields is supported below by economic studies that show that equity risk premiums are higher when interest rates are at very low levels.

IV. SELECTION OF A PROXY GROUP

Q36. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A36. This section discusses the identification of a proxy group of other gas utilities and examines alternative objective indicators of investment risk applicable to the group. In addition, I evaluate the investment risks of NorthWestern against those of the reference group I use to estimate the cost of equity.

A. Gas Utility Group

Q37. HOW DID YOU IMPLEMENT QUANTITATIVE METHODS TO ESTIMATE THE COST OF COMMON EQUITY FOR NORTHWESTERN?

A37. Application of quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply quantitative methods to a proxy group of publicly traded companies that investors regard as risk-comparable.

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[24] *Ind. Michigan Power Co.*, Cause No. 38728, 116 PUR4th, 1, 17-18 (IURC 8/24/1990).

1 **Q38. WHAT SPECIFIC PROXY GROUP OF UTILITIES DID YOU RELY ON FOR**
2 **YOUR ANALYSIS?**
3 **A38.** In order to reflect the risks and prospects associated with NorthWestern's Montana
4 jurisdictional gas utility operations, I examined quantitative estimates of investors'
5 required ROE for a group of natural gas utilities, consisting of eight publicly traded
6 firms included in Value Line's Natural Gas Utility industry.[25] I refer to these utilities
7 as the Gas Group.
8 **Q39. HOW DID YOU EVALUATE THE INVESTMENT RISKS OF THE GAS**
9 **GROUP?**
10 **A39.** My evaluation of relative risk considered four objective, published benchmarks that
11 are widely relied on in the investment community. Credit ratings are assigned by
12 independent rating agencies for the purpose of providing investors with a broad
13 assessment of the creditworthiness of a firm. Ratings generally extend from triple-A
14 (the highest) to D (in default).[26] Other symbols (*e.g.*, "+" or "-") are used to show
15 relative standing within a category. Because the rating agencies' evaluation includes
16 virtually all of the factors normally considered important in assessing a firm's relative
17 credit standing, corporate credit ratings provide a broad, objective measure of overall
18 investment risk that is readily available to investors. Widely cited in the investment
19 community and referenced by investors, credit ratings are also frequently used as a

[25] I excluded one firm (UGI Corporation) that was included in Value Line's Natural Gas Utility Industry because it is primarily engaged in propane sales and marketing. AGL Resources Inc. and Piedmont Natural Gas Company, Inc. were eliminated due to merger and acquisition activity. NiSource was eliminated due to distortions related to its Columbia Pipeline spinoff. In April, 2016, The Laclede Group changed its name to Spire Inc.

[26] Credit rating firms, such as S&P, use designations consisting of upper- and lower-case letters 'A' and 'B' to identify a bond's credit quality rating. 'AAA', 'AA', 'A', and 'BBB' ratings are considered investment grade. Credit ratings for bonds below these designations ('BB', 'B', 'CCC', etc.) are considered speculative grade, and are commonly referred to as "junk bonds". The term "investment grade" refers to bonds with ratings in the 'BBB' category and above.

1 primary risk indicator in establishing proxy groups to estimate the cost of common
2 equity.
3 While credit ratings provide the most widely referenced benchmark for
4 investment risks, other quality rankings published by investment advisory services
5 also provide relative assessments of risks that are considered by investors in forming
6 their expectations for common stocks. Value Line's primary risk indicator is its Safety
7 Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is
8 intended to capture the total risk of a stock, and incorporates elements of stock price
9 stability and financial strength. Given that Value Line is perhaps the most widely
10 available source of investment advisory information, its Safety Rank provides useful
11 guidance regarding the risk perceptions of investors.
12 The Financial Strength Rating is designed as a guide to overall financial
13 strength and creditworthiness, with the key inputs including financial leverage,
14 business volatility measures, and company size. Value Line's Financial Strength
15 Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. These
16 objective, published indicators incorporate consideration of a broad spectrum of risks,
17 including financial and business position, relative size, and exposure to firm-specific
18 factors.
19 Finally, beta measures a utility's stock price volatility relative to the market as
20 a whole, and reflects the tendency of a stock's price to follow changes in the market.
21 A stock that tends to respond less to market movements has a beta less than 1.00,
22 while stocks that tend to move more than the market have betas greater than 1.00.
23 Beta is the only relevant measure of investment risk under modern capital market
24 theory, and is widely cited in academia and in the investment industry as a guide to
25 investors' risk perceptions. Moreover, in my experience, Value Line is the most

widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. … Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[27]

B. NorthWestern's Relative Risks

Q40. WHAT DO THE RISK MEASURES DISCUSSED ABOVE INDICATE WITH RESPECT TO THE RELATIVE RISK OF THE COMPANY?

A40. The average risk indicators for the Gas Group and NorthWestern Corp. are shown in Table 3, below:

TABLE 3
COMPARISON OF RISK INDICATORS
PROSPECTIVE PERIOD

	S&P	Moody's	Value Line		
Company	**Credit Rating**	**Issuer Rating**	**Safety Rank**	**Financial Strength**	**Beta**
Gas Group	A	A2	2	A	0.73
NorthWestern Corp.	BBB	A3	3	B+	0.70

The average single-A ratings corresponding to the Gas Group place their credit risks solidly within the investment grade range. Similarly, the average Value Line risk indicators for the Gas Group, which incorporate a broad spectrum of risks, including financial and business position and exposure to company specific factors, are generally indicative of a company with a conservative risk profile.

Relative to those of the proxy group, the Company's indicators imply a higher level of risk. Credit ratings along with scores for Safety Rank and Financial Strength

[27] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 71 (2006).

all indicate greater risk associated with NorthWestern, as compared to the Gas Group. The marginally lower beta value is the only indicator that is suggestive of a slightly lower risk level for the Company compared to the proxy group.

Q41. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS RETURN ON EQUITY?

A41. Yes. Other things equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow that will remain.

Q42. WHAT COMMON EQUITY RATIO IS IMPLICIT IN NORTHWESTERN'S CAPITAL STRUCTURE?

A42. The capital structure used to compute the overall rate of return for NorthWestern includes approximately 46.79% common equity.

Q43. HOW DOES THIS COMPARE TO THE AVERAGE CAPITALIZATION MAINTAINED BY THE GAS GROUP?

A43. As shown on Exhibit__(AMM-4), for the firms in the Gas Group, common equity ratios at December 31, 2015 ranged from 45.9% to 69.3% and averaged 55.1% of total long-term debt and equity, with Value Line expecting an average common equity ratio of 55.4% for its three-to-five year forecast horizon. Thus, NorthWestern's common equity ratio falls well below these industry benchmarks and indicates greater financial risk than what investors would associate with the Gas Group.

V. CAPITAL MARKET ESTIMATES

Q44. WHAT IS THE PURPOSE OF THIS SECTION?

A44. This section presents capital market estimates of the ROE. First, I address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe the DCF, CAPM, ECAPM, risk premium, and expected earnings analyses conducted to estimate the cost of common equity for the benchmark group of gas utilities.

A. Economic Standards

Q45. WHAT ROLE DOES THE ROE PLAY IN A UTILITY'S RATES?

A45. The return component of a utility's revenue requirements compensates common equity investors for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield* and *Hope* cases, a utility's allowed equity return should be sufficient to: (1) fairly compensate investors for capital invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity. Meeting these objectives allows the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system expansion.

Q46. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THE COST OF EQUITY CONCEPT?

A46. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of

return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q47. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A47. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. Comparing the observed yields on government securities, which are considered free of default risk, to the yields on bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

Q48. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A48. It is widely accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common

stock – required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q49. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A49. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. As noted earlier, long-term debt is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. The last investors in line are common shareholders: they receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q50. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE ROE FOR A UTILITY?

A50. Although the ROE cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is not readily observable, the ROE for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

Q51. DID YOU RELY ON A SINGLE METHOD TO ESTIMATE THE COST OF EQUITY FOR NORTHWESTERN?

A51. No. In my opinion, no single method or model should be relied upon to determine a utility's cost of equity because no single approach can be regarded as wholly reliable. Therefore, I used the DCF, CAPM, ECAPM and risk premium methods to estimate the cost of common equity. In addition, I also evaluated a fair ROE using an expected earnings approach based on investors' current expectations in the capital markets. In my opinion, comparing estimates produced by one method with those produced by other approaches ensures that the estimates of the cost of equity pass fundamental tests of reasonableness and economic logic.

B. Discounted Cash Flow Analyses

Q52. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF COMMON EQUITY?

A52. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. That is, the cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock. The formula for the general form of the DCF model is as follows:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where: P_0 = Current price per share;
P_t = Expected future price per share in period t;
D_t = Expected dividend per share in period t;
k_e = Cost of common equity.

Q53. WHAT FORM OF THE DCF MODEL IS CUSTOMARILY USED TO ESTIMATE THE COST OF COMMON EQUITY IN RATE CASES?

A53. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[28]

$$P_0 = \frac{D_1}{k_e - g}$$

where: g = Investors' long-term growth expectations.

The cost of common equity (k_e) can be isolated by rearranging terms within the equation:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and, 2) growth (*g*). In other words, investors expect to receive a portion of their total return in the form of

[28] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity.

future dividends and the remainder through the capital gains associated with price appreciation over the investors' holding period.

Q54. WHAT FORM OF THE DCF MODEL DID YOU USE?

A54. I applied the constant growth DCF model to estimate the cost of common equity for NorthWestern, which is the form of the model most commonly relied on to establish the cost of common equity for traditional regulated utilities and the method most often referenced by regulators.

Q55. HOW IS THE CONSTANT GROWTH FORM OF THE DCF MODEL TYPICALLY USED TO ESTIMATE THE COST OF COMMON EQUITY?

A55. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (g) for the firm. The final step is to add the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

Q56. HOW DID YOU DETERMINE THE DIVIDEND YIELD FOR THE GAS GROUP?

A56. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by a 30-day average stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Gas Group are presented on Exhibit__(AMM-5). As shown on page 1, dividend yields for the firms in the Gas Group ranged from 2.1% to 3.7% and averaged 2.8%.

Q57. WHAT IS THE NEXT STEP IN APPLYING THE CONSTANT GROWTH DCF MODEL?

A57. The next step is to evaluate long-term growth expectations, or "*g*", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q58. WHAT ARE INVESTORS MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A58. Given that the DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors, in the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry, with the payout ratios falling significantly. As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties.

A measure that plays a pivotal role in determining investors' long-term growth expectations are future trends in earnings per share ("EPS"), which provide the source for future dividends and ultimately support share prices. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional

analysts indicate that growth in earnings is far more influential than trends in dividends per share ("DPS").

The availability of projected EPS growth rates also is key to investors relying on this measure as compared to future trends in DPS. Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of earnings forecasts attests to their relative influence. The fact that securities analysts focus on EPS growth, and that DPS growth rates are not routinely published, indicates that projected EPS growth rates are likely to provide a superior indicator of the future long-term growth expected by investors.

Q59. DO THE GROWTH RATE PROJECTIONS OF SECURITY ANALYSTS CONSIDER HISTORICAL TRENDS?

A59. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q60. DID PROFESSOR MYRON J. GORDON, WHO ORIGINATED THE DCF APPROACH, RECOGNIZE THE PIVOTAL ROLE THAT EARNINGS PLAY IN FORMING INVESTORS' EXPECTATIONS?

A60. Yes. Dr. Gordon specifically recognized that "it is the growth that investors expect that should be used" in applying the DCF model and he concluded:

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth.[29]

[29] Gordon, Myron J., "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* at 89 (1974).

Q61. ARE ANALYSTS' ASSESSMENTS OF GROWTH RATES APPROPRIATE FOR ESTIMATING INVESTORS' REQUIRED RETURN USING THE DCF MODEL?

A61. Yes. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, then it is irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications, as well as the continued success of services such as Thomson Reuters and Value Line, implies that investors use them as a basis for their expectations.

While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. The accuracy of these forecasts in the sense of whether they turn out to be correct is not an issue here, as long as they reflect widely held expectations.[30]

Q62. WHAT ARE SECURITY ANALYSTS CURRENTLY PROJECTING IN THE WAY OF GROWTH FOR THE FIRMS IN THE GAS GROUP?

A62. The earnings growth projections for each of the firms in the Gas Group reported by Value Line, Thomson Reuters ("IBES"), and Zacks Investment Research ("Zacks") are displayed on page 2 of Exhibit__(AMM-5).[31]

Q63. HOW ELSE ARE INVESTORS' EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS OFTEN ESTIMATED WHEN APPLYING THE CONSTANT GROWTH DCF MODEL?

A63. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are never met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

The sustainable growth rate is calculated by the formula, $g = br+sv$, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate. Under DCF theory, the "sv" factor is a component of

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[30] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006) (emphasis added).
[31] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. The sustainable, "br+sv" growth rates for each firm in the Gas Group are summarized on page 2 of Exhibit__(AMM-5), with the underlying details being presented in Exhibit__(AMM-6).

Q64. WHAT COST OF COMMON EQUITY ESTIMATES WERE IMPLIED FOR THE GAS GROUP USING THE DCF MODEL?

A64. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on page 3 of Exhibit__(AMM-5).

Q65. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE ESTIMATES THAT ARE EXTREME LOW OR HIGH OUTLIERS?

A65. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

Q66. HOW DID YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A66. I based my evaluation of DCF estimates at the low end of the range on the fundamental risk-return tradeoff, which holds that investors will only take on more risk if they expect to earn a higher rate of return to compensate them for the greater uncertainty. Because common stocks lack the protections associated with an investment in long-term bonds, a utility's common stock imposes far greater risks on investors. As a result, the rate of return that investors require from a utility's common stock is considerably higher than the yield offered by senior, long-term debt.

Consistent with this principle, DCF results that are not sufficiently higher than the yield available on less risky utility bonds must be eliminated.

Q67. HAVE SIMILAR TESTS BEEN APPLIED BY REGULATORS?

A67. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold.[32] FERC affirmed that:

> The purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt. In public utility ROE cases, the Commission has used 100 basis points above the cost of debt as an approximation of this threshold, but has also considered the distribution of proxy group companies to inform its decision on which companies are outliers. As the Presiding Judge explained, this is a flexible test.[33]

Q68. WHAT INTEREST RATE BENCHMARK DID YOU CONSIDER IN EVALUATING THE DCF RESULTS FOR NORTHWESTERN?

A68. Baa utility bonds represent the lowest ratings grade for which Moody's publishes index values, and the closest available approximation for the risks of common stock, which are significantly greater than those of long-term debt. Monthly yields on Baa utility bonds reported by Moody's averaged approximately 5.0% over the six months ended June 2016.[34]

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[32] *See, e.g., Southern California Edison Co.,* 131 FERC ¶ 61,020 at P 55 (2010) ("*SoCal Edison*").
[33] *Martha Coakley et al., v. Bangor Hydro-Electric Company, et al.,* Opinion No. 531, 147 FERC ¶ 61,234 at P 122 (2014).
[34] Moody's Investors Service, http://credittrends.moodys.com/chartroom.asp?c=3.

1 **Q69. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF**

2 **ESTIMATES AT THE LOW END OF THE RANGE?**

3 **A69.** As indicated earlier, it is generally expected that long-term interest rates will rise as

4 the Federal Reserve normalizes monetary policies. As shown in Table 4 below,

5 forecasts by IHS Global Insight and the EIA imply an average triple-B bond yield of

6 approximately 6.6% over the period 2017-2021:

TABLE 4
IMPLIED BBB BOND YIELD

	2017-21
Projected Aa Utility Yield	
IHS Global Insight (a)	5.41%
EIA (b)	5.50%
Average	5.46%
Current Baa - Aa Yield Spread (c)	1.13%
Implied Baa Utility Yield	**6.59%**

(a) IHS Global Insight (Apr. 6 & Jun. 27, 2016).
(b) Energy Information Administration, Annual Energy Outlook 2016 Early Release (May 17, 2016).
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Jan. - June 2016.

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8 The increase in debt yields anticipated by IHS Global Insight and EIA is also

9 supported by the widely referenced Blue Chip Financial Forecasts, which projects that

10 yields on corporate bonds will climb 180 basis points through 2021.[35]

11 **Q70. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF**

12 **RESULTS FOR THE GAS GROUP?**

13 **A70.** Adding a 100 basis-point premium to the historical and projected average Baa utility

14 bond yields implies a low-end threshold on the order of 6.0% to 7.6%. As highlighted

[35] *Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 35, No. 6 (Jun. 1, 2016).*

on page 3 of Exhibit__(AMM-5), after considering this test and the distribution of the individual estimates, I eliminated five low-end DCF estimates ranging from 4.1% to 6.9%. It is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock.

Q71. IS THERE A BASIS TO ELIMINATE HIGH-END DCF VALUES FOR THE GAS GROUP?

A71. While it is just as important to evaluate DCF estimates at the upper end of the range, there is no objective benchmark analogous to the bond yield averages used to eliminate illogical low-end values. In response, FERC has consistently applied a two-pronged test for high-end values based on the magnitude of the cost of equity estimate and its underlying growth rate. As FERC observed:

> The Presiding Judge found that the [utilities'] criteria for screening high-end outliers substantially complies with Commission precedent. . . The Presiding Judge further stated that the Commission's high-end outlier test since 2004 has been to exclude from the proxy group any company whose cost of equity estimate is at or above 17.7 percent and whose growth rate is at or above 13.3 percent.[36]

Based on these principles, I reviewed the DCF results and determined that the ROE estimate for Chesapeake Utilities at 19.8% (including a growth rate of 17.7%) was unreasonably high and should be removed. Beyond this, the upper end of the DCF range for the Gas Group was set by a cost of equity estimate of 12.5%. This cost of equity estimate, and the underlying growth rate of 10.2%, falls well below the threshold tests employed by FERC. Moreover, while this cost of equity estimate may exceed the majority of the remaining values, remaining low-end estimates in the 7.0% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the DCF estimates, these values provide a

[36] Opinion No. 531 at P 115 (footnotes omitted).

reasonable basis on which to frame the range of plausible DCF estimates and evaluate investors' required rate of return.

Q72. WHAT ROE ESTIMATES ARE IMPLIED BY YOUR DCF RESULTS FOR THE GAS GROUP?

A72. As shown on page 3 of Exhibit__(AMM-5) and summarized in Table 5, below, after eliminating illogical values, application of the constant growth DCF model resulted in the following ROE estimates:

TABLE 5
DCF RESULTS – GAS GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	9.7%	9.9%
IBES	9.0%	9.0%
Zacks	8.6%	8.7%
br + sv	9.1%	10.2%

C. Capital Asset Pricing Model

Q73. WHY IS THE CAPM APPROACH AN APPROPRIATE COMPONENT IN EVALUATING THE ROE FOR THE COMPANY?

A73. The CAPM approach generally is considered to be the most widely referenced method among academicians and professional practitioners for estimating the cost of equity, with the pioneering researchers of this method receiving the Nobel Prize in 1990. Because this is a dominant model for estimating the cost of equity outside the regulatory sphere, the CAPM provides important insight into investors' ROE for utility companies, including NorthWestern.

Q74. PLEASE DESCRIBE THE CAPM.

A74. The traditional CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an

individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. As previously stated, a stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q75. HOW DID YOU APPLY THE CAPM TO ESTIMATE THE ROE?

A75. Application of the CAPM to the Gas Group is based on a forward-looking estimate for investors' required rate of return from common stocks presented in Exhibit__(AMM-7). In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm was obtained from Value Line, and the growth rate was equal to the average of the EPS growth projections for each firm published by IBES and Value Line, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the individual firms, current estimates imply an average growth rate over the next five years of 9.0%. Combining this average

growth rate with a year-ahead dividend yield of 2.6% results in a current cost of common equity estimate for the market as a whole (R_m) of approximately 11.6%. Subtracting a 2.6% risk-free rate based on the average yield on 30-year Treasury bonds for the six months ending June 2016 produced a market equity risk premium of 9.0%.

Q76. WHAT WAS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE CAPM?

A76. As indicated earlier, I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings.

Q77. WHAT ELSE SHOULD BE CONSIDERED IN APPLYING THE CAPM?

A77. As *Morningstar* noted in its publication of historical return data:

> One of the most remarkable discoveries of modern finance is the finding of a relationship between firm size and return. On average, small companies have higher returns than large ones. . . . The relationship between firm size and return cuts across the entire size spectrum; it is not restricted to the smallest stocks.[37]

Because financial research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect.

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, Morningstar has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market

[37] Morningstar, *2015 Ibbotson SBBI Classic Yearbook,* at 99.

capitalization in determining the CAPM cost of equity. These premiums correspond to the size deciles of publicly traded common stocks, and range from a premium of approximately 5.6% for a company in the first decile (market capitalization less than $209.9 million), to a reduction of 36 basis points for firms in the tenth decile (market capitalization greater than $22.0 billion).[38] Accordingly, my CAPM analyses also incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the Gas Group.

Q78. WHAT IS THE IMPLIED ROE FOR THE GAS GROUP USING THE CAPM APPROACH?

A78. As shown on page 1 of Exhibit__(AMM-7), a forward-looking application of the CAPM approach resulted in an average unadjusted ROE estimate of 9.1%.[39] After adjusting for the impact of firm size, the CAPM approach implied an average ROE of 10.4% for the Gas Group, with a midpoint ROE estimate of 10.5%.

Q79. DID YOU ALSO APPLY THE CAPM USING FORECASTED BOND YIELDS?

A79. Yes. As discussed earlier, there is widespread consensus that interest rates will increase materially as the economy continues to strengthen and the Federal Reserve normalizes its monetary policy. Accordingly, in addition to the use of historical bond yields, I also applied the CAPM based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight and Blue Chip. As shown on page 2 of Exhibit__(AMM-7), incorporating a forecasted Treasury bond yield for 2017-2021 implied a ROE of 9.5% for the Gas Group, or 10.7% after adjusting for the impact of relative size. The midpoints of the unadjusted and size adjusted ROE ranges were 9.3% and 10.8%, respectively.

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[38] *Duff & Phelps,* "2016 Valuation Handbook – Guide to Cost of Capital (Preview Version)," John Wiley & Sons (2016).

[39] The midpoint of the unadjusted CAPM range was 8.9%.

D. Empirical Capital Asset Pricing Model

Q80. HOW DOES THE ECAPM APPROACH DIFFER FROM TRADITIONAL APPLICATIONS OF THE CAPM?

A80. Empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta, with low-beta stocks tending to have higher returns and high-beta stocks tending to have lower returns than predicted by the CAPM. This empirical finding is widely reported in the finance literature, as summarized in *New Regulatory Finance*:

> As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical relationships.[40]

As discussed in *New Regulatory Finance*,[41] based on a review of the empirical evidence, the expected return on a security is related to its risk by the ECAPM, which is represented by the following formula:

$$Rj = Rf + 0.25(Rm - Rf) + 0.75[\beta j(Rm - Rf)]$$

This ECAPM equation, and the associated weighting factors, recognize the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research, and correct for the understated returns that would otherwise be produced for low beta stocks.

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[40] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports* at 189 (2006).
[41] *Id.* at 190.

Q81. WHAT ROE ESTIMATES WERE INDICATED BY THE ECAPM?

A81. My applications of the ECAPM were based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connections with the CAPM. As shown on page 1 of Exhibit__(AMM-8), applying the forward-looking ECAPM approach to the firms in the Gas Group results in an average theoretical cost of equity estimate of 9.7%, or 11.0% after incorporating the size adjustment corresponding to the market capitalization of the individual utilities.

As shown on page 2 of Exhibit__(AMM-8), incorporating a forecasted Treasury bond yield for 2017-2021 implied a ROE of approximately 10.0% for the Gas Group, or 11.3% after adjusting for the impact of relative size.

E. Utility Risk Premium

Q82. BRIEFLY DESCRIBE THE RISK PREMIUM METHOD.

A82. The risk premium method extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q83. IS THE RISK PREMIUM APPROACH A WIDELY ACCEPTED METHOD FOR ESTIMATING THE COST OF EQUITY?

A83. Yes. The risk premium approach is based on the fundamental risk-return principle that is central to finance, which holds that investors will require a premium in the form of a higher return in order to assume additional risk. This method is routinely referenced

by the investment community and in academia and regulatory proceedings, and provides an important tool in estimating a fair ROE for NorthWestern.

Q84. HOW DID YOU IMPLEMENT THE RISK PREMIUM METHOD?

A84. Estimates of equity risk premiums for utilities were based on surveys of previously authorized ROEs. Authorized ROEs presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such ROEs should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, these data provide a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q85. IS IT CIRCULAR TO CONSIDER RISK PREMIUMS BASED ON AUTHORIZED RETURNS IN ASSESSING A FAIR ROE FOR NORTHWESTERN?

A85. No. In establishing authorized ROEs, regulators typically consider the results of alternative market-based approaches, including the DCF model. Because allowed risk premiums consider objective market data (*e.g.*, stock prices, dividends, beta, and interest rates), and are not based strictly on past actions of other regulators, this mitigates concerns over any potential for circularity.

Q86. HOW DID YOU CALCULATE THE EQUITY RISK PREMIUMS BASED ON ALLOWED ROES?

A86. The ROEs authorized for gas utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates and published in its *Regulatory Focus* report. In Exhibit__(AMM-9), the average yield on single-A public utility bonds is subtracted from the average allowed ROE for gas utilities to calculate equity risk

premiums for each quarter between 1980 and the second quarter of 2016. As shown on page 3 of Exhibit__(AMM-9), over this period, these equity risk premiums for gas utilities averaged 3.43%, and the yield on single-A public utility bonds averaged 8.31%.

Q87. IS THERE ANY CAPITAL MARKET RELATIONSHIP THAT MUST BE CONSIDERED WHEN IMPLEMENTING THE RISK PREMIUM METHOD?

A87. Yes. There is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates.[42] In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1% increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have diverged from the average interest rate level represented in the data set.

Q88. HAS THIS INVERSE RELATIONSHIP BEEN DOCUMENTED IN THE FINANCIAL RESEARCH?

A88. Yes. There is considerable empirical evidence that when interest rates are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums are greater.[43] This inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature. For example, *New Regulatory Finance* documented this inverse relationship:

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[42] *See, e.g.,* Brigham, E.F., Shome, D.K., and Vinson, S.R., "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management* (Spring 1985); Harris, R.S., and Marston, F.C., "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management* (Summer 1992).
[43] *Id.*

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carelton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose.[44]

Other regulators have also recognized that the cost of equity does not move in tandem with interest rates.[45]

Q89. WHAT ARE THE IMPLICATIONS OF THIS RELATIONSHIP UNDER CURRENT CAPITAL MARKET CONDITIONS?

A89. As noted earlier, bond yields are at unprecedented lows. Given that equity risk premiums move inversely with interest rates, these uncharacteristically low bond yields also imply a sharp increase in the equity risk premium that investors require to accept the higher uncertainties associated with an investment in utility common stocks versus bonds. In other words, higher required equity risk premiums offset the impact of declining interest rates on the ROE.

Q90. WHAT ROE IS IMPLIED BY THE RISK PREMIUM METHOD USING SURVEYS OF ALLOWED ROES?

A90. Based on the regression output between the interest rates and equity risk premiums displayed on page 4 of Exhibit__(AMM-9), the equity risk premium for gas utilities increased approximately 46 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit__(AMM-9), with an average yield on single-A public utility bonds for the six-months ending June 2016 of 4.04%, this implied a current equity risk premium of 5.41% for gas utilities. Adding

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[44] Morin, Roger A., "New Regulatory Finance," Public Utilities Reports, at 128 (2006).

[45] *See, e.g.*, California Public Utilities Commission, Decision 08-05-035 (May 29, 2008); Entergy Mississippi Formula Rate Plan FRP-5, http://www.entergy-mississippi.com/content/price/tariffs/emi_frp.pdf; *Martha Coakley et al.*, 147 FERC ¶ 61,234 at P 147 (2014).

this equity risk premium to the average yield on triple-B utility bonds for the six-months ended June 2016 of 4.95% implies a current ROE of approximately 10.36%.

Q91. WHAT RISK PREMIUM ROE ESTIMATES WERE PRODUCED FOR NORTHWESTERN'S GAS UTILITY OPERATIONS AFTER INCORPORATING FORECASTED BOND YIELDS?

A91. As shown on page 2 of Exhibit__(AMM-9), incorporating a forecasted yield for 2017-2021 and adjusting for changes in interest rates since the study period implied an equity risk premium of 4.65% for gas utilities. Adding this equity risk premium to the implied average yield on triple-B public utility bonds for 2017-2021 of 6.59% resulted in an implied ROE of approximately 11.24%.

F. Expected Earnings Approach

Q92. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE ROE?

A92. As I noted earlier, I also evaluated the ROE using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is consistent with the economic underpinnings for a fair rate of return established by the U.S. Supreme Court in *Bluefield* and *Hope*. Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q93. WHAT ECONOMIC PREMISE UNDERLIES THE EXPECTED EARNINGS APPROACH?

A93. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of

comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. In this situation regulation is effectively taking the value of investors' capital without adequate compensation, contrary to *Hope* and *Bluefield*. The expected earnings approach is consistent with the economic rationale underpinning established regulatory standards, which specifies a methodology to determine an ROE benchmark based on earned rates of return for a peer group of other regional utilities.

Q94. HOW IS THE EXPECTED EARNINGS APPROACH TYPICALLY IMPLEMENTED?

A94. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Moreover, regulators do not set the returns that investors earn in the capital markets, which are a function of dividend payments and fluctuations in common stock prices – both of which are outside their control. Regulators can only establish the allowed ROE, which is applied to the book value of a utility's investment in rate base, as determined from its accounting records. This is directly analogous to the expected earnings approach, which measures the return that investors expect the utility to earn

on book value. As a result, the expected earnings approach provides a meaningful guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. As FERC concluded:

> The returns on book equity that investors expect to receive from a group of companies with risks comparable to those of a particular utility are relevant to determining that utility's market cost of equity, because those returns on book equity help investors determine the opportunity cost of investing in that particular utility instead of other companies of comparable risk.[46]

This expected earnings test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q95. WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR GAS UTILITIES BASED ON THE EXPECTED EARNINGS APPROACH?

A95. Value Line's projected year-end returns on common equity for the firms in the Gas Group are shown in Exhibit__(AMM-10). Consistent with the rationale underlying the development of the br+sv growth rates, these year-end values were converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit__(AMM-6). As shown in Exhibit__(AMM-10), Value Line's projections for the Gas Group suggest an average ROE of approximately 11.3%.

[46] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 128 (2015).

G. Non-Utility Benchmark

1 **Q96. WHAT OTHER PROXY GROUP DID YOU CONSIDER IN EVALUATING A**
2 **ROE FOR NORTHWESTERN?**
3 **A96.** Consistent with underlying economic and regulatory standards, I also applied the DCF
4 model to a reference group of low-risk companies in the non-utility sectors of the
5 economy. I refer to this group as the "Non-Utility Group".
6 **Q97. DO UTILITIES HAVE TO COMPETE WITH NON-REGULATED FIRMS**
7 **FOR CAPITAL?**
8 **A97.** Yes. The cost of capital is an opportunity cost based on the returns that investors
9 could realize by putting their money in other alternatives. Clearly, the total capital
10 invested in utility stocks is only the tip of the iceberg of total common stock
11 investment, and there are a plethora of other enterprises available to investors beyond
12 those in the utility industry. Utilities must compete for capital, not just against firms in
13 their own industry, but with other investment opportunities of comparable risk.
14 Indeed, modern portfolio theory is built on the assumption that rational investors will
15 hold a diverse portfolio of stocks, not just companies in a single industry.
16 **Q98. IS IT CONSISTENT WITH THE BLUEFIELD AND HOPE CASES TO**
17 **CONSIDER INVESTORS' REQUIRED ROE FOR NON-UTILITY**
18 **COMPANIES?**
19 **A98.** Yes. The cost of equity capital in the competitive sector of the economy forms the
20 very underpinning for utility ROEs because regulation purports to serve as a substitute
21 for the actions of competitive markets. The Supreme Court has recognized that it is
22 the degree of risk, not the nature of the business, which is relevant in evaluating an
23 allowed ROE for a utility. The *Bluefield* case refers to "business undertakings
24 attended with comparable risks and uncertainties." It does not restrict consideration to
25 other utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[47]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Q99. DOES CONSIDERATION OF THE RESULTS FOR THE NON-UTILITY GROUP IMPROVE THE RELIABILITY OF DCF RESULTS?

A99. Yes. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry, or by the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities. Because the Non-Utility Group includes low risk companies from more than one industry, it helps to insulate against any possible distortion that may be present in results for a particular sector.

Q100. WHAT CRITERIA DID YOU APPLY TO DEVELOP THE NON-UTILITY GROUP?

A100. My comparable risk proxy group was composed of those United States companies followed by Value Line that:

1) pay common dividends;
2) have a Safety Rank of "1";
3) have a Financial Strength Rating of "A" or greater;
4) have a beta of 0.75 or less; and
5) have investment grade credit ratings from S&P and Moody's.[48]

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[47] *Federal Power Comm'n v. Hope Natural Gas Co.* 320 U.S. 391, (1944).

[48] As described earlier, the term "investment grade" refers to bonds with ratings in the 'BBB' category and above.

1 **Q101. HOW DO THE OVERALL RISKS OF THIS NON-UTILITY GROUP**

2 **COMPARE WITH THE GAS GROUP?**

3 **A101.** Table 6 compares the Non-Utility Group with the Gas Group and NorthWestern Corp.

4 across the measures of investment risk discussed earlier:

TABLE 6
COMPARISON OF RISK INDICATORS

Company	S&P Credit Rating	Moody's Issuer Rating	Value Line Safety Rank	Value Line Financial Strength	Beta
Non-Utility Group	A	A2	1	A+	0.71
Gas Group	A	A2	2	A	0.73
NorthWestern Corp.	BBB	A3	3	B+	0.70

5 When viewed together, a comparison of these objective measures, which consider a

6 broad spectrum of risks, including financial and business position, relative size, and

7 exposure to company-specific factors, indicates that investors would likely conclude

8 that the overall investment risks for the Gas Group are comparable to (or greater than)

9 those of the firms in the Non-Utility Group. All of the risk metrics (except beta) point

10 to lower risk for the Non-Utility Group as compared to NorthWestern Corporation.

11 The companies that make up the Non-Utility Group are representative of the

12 pinnacle of corporate America. These firms, which include household names such as

13 Coca-Cola, McDonalds, Proctor & Gamble, and Wal-Mart, have long corporate

14 histories, well-established track records, and exceedingly conservative risk profiles.

15 Many of these companies pay dividends on a par with utilities, with the average

16 dividend yield for the group approaching 3%. Moreover, because of their significance

17 and name recognition, these companies receive intense scrutiny by the investment

18 community, which increases confidence that published growth estimates are

19 representative of the consensus expectations reflected in common stock prices.

Q102. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY GROUP?

A102. I applied the DCF model to the Non-Utility Group using the same analysts' EPS growth projections described earlier for the Gas Group. The results of my DCF analysis for the Non-Utility Group are presented in Exhibit__(AMM-11). As summarized in Table 7, below, after eliminating illogical low-end and high-end values, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE 7
DCF RESULTS – NON-UTILITY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	10.6%	11.4%
IBES	10.5%	11.8%
Zacks	10.3%	11.2%

As discussed earlier, reference to the Non-Utility Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Because the actual cost of equity is unobservable, and DCF results inherently incorporate a degree of error, the ROE estimates for the Non-Utility Group provide an important benchmark in evaluating a ROE for NorthWestern. Moreover, as illustrated in Table 6, objective indicators relied on by the investment community indicate that the investment risks of the Non-Utility Group are lower than those of NorthWestern. Accordingly, the DCF results for the Non-Utility Group are likely to understate investors' required rate of return for the Company.

H. Flotation Costs

1 **Q103. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN SETTING THE**
2 **RETURN ON EQUITY FOR A UTILITY?**

3 **A103.** The common equity used to finance the investment in utility assets is provided from
4 either the sale of stock in the capital markets or from retained earnings not paid out as
5 dividends. When equity is raised through the sale of common stock, there are costs
6 associated with "floating" the new equity securities. These flotation costs include
7 services such as legal, accounting, and printing, as well as the fees and discounts paid
8 to compensate brokers for selling the stock to the public. Also, some argue that the
9 "market pressure" from the additional supply of common stock and other market
10 factors may further reduce the amount of funds a utility nets when it issues common
11 equity.

12 **Q104. IS THERE AN ESTABLISHED MECHANISM FOR A UTILITY TO**
13 **RECOGNIZE EQUITY ISSUANCE COSTS?**

14 **A104.** No. While debt flotation costs are recorded on the books of the utility, amortized over
15 the life of the issue, and thus increase the effective cost of debt capital, there is no
16 similar accounting treatment to ensure that equity flotation costs are recorded and
17 ultimately recognized. No rate of return is authorized on flotation costs necessarily
18 incurred to obtain a portion of the equity capital used to finance plant. In other words,
19 equity flotation costs are not included in a utility's rate base because that portion of the
20 gross proceeds from the sale of common stock used to pay flotation costs is available to
21 invest in plant and equipment, nor are flotation costs capitalized as an intangible asset.
22 Unless some provision is made to recognize these issuance costs, a utility's revenue
23 requirements will not fully reflect all of the costs incurred for the use of investors' funds.
24 Because there is no accounting convention to accumulate the flotation costs associated

with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most common and appropriate mechanism.

Q105. IS THERE A THEORETICAL AND PRACTICAL BASIS TO INCLUDE A FLOTATION COST ADJUSTMENT IN THIS CASE?

A105. Yes. First, an adjustment for flotation costs associated with past equity issues is appropriate, even when the utility is not contemplating any new sales of common stock. The need for a flotation cost adjustment to compensate for past equity issues been recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[49] Similarly, *New Regulatory Finance* contains the following discussion:

> Another controversy is whether the flotation cost allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. … The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[50]

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[49] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly,* May, 2, 1985.

[50] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 335 (2006).

Q106. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF EQUITY TO ACCOUNT FOR ISSUANCE COSTS?

A106. There are a number of ways in which a flotation cost adjustment can be calculated, but the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, *Regulatory Finance: Utilities' Cost of Capital* concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[51]

Alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6%.[52]

Issuance costs are a legitimate consideration in setting the return on equity for a utility, and applying these expense percentages to an average dividend yield of 2.8% implies a minimum flotation cost adjustment on the order of 10 basis points.[53]

Q107. DID YOU INCLUDE A FLOTATION COST ADJUSTMENT IN ARRIVING AT YOUR RECOMMENDED ROE?

A107. No. The fact that I am not increasing my ROE to account for flotation costs, which are a legitimate utility expense, further supports the reasonableness of my recommendation.

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[51] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 323 (2006).

[52] *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1. Updating the results presented by Mr. Eckenroth through April 2005 also resulted in an average flotation cost percentage of 3.6%.

[53] 3.6% x 2.8%=0.10%

VI. ROE FOR NATURAL GAS PRODUCTION ASSETS - TRUE UP

Q108. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A108. As I noted previously, NorthWestern proposes a Natural Gas Production Assets True Up in this filing. The purpose of this section is to evaluate a fair ROE for purposes of NorthWestern's reconciliation.

Q109. HOW DID YOU EVALUATE A FAIR ROE FOR PURPOSES OF NORTHWESTERN'S TRUE UP?

A109. I employed the same methods and approaches described earlier in Section V of my testimony. Consistent with Mr. Rausch's testimony, and in order to reflect data corresponding to the period during which the interim rates at issue were in effect, I relied on capital market data available as of mid-2014. Because my approach mirrors that described above for the forward-looking ROE, I will not duplicate that discussion here. The results of my analyses are presented in the following schedules, which are attached to my testimony as Exhibit__(AMM-12):

Schedule	Description
Schedule 1	Regulatory Mechanisms
Schedule 2	Capital Structure
Schedule 3	Summary of Results
Schedule 4	DCF Model – Gas Group
Schedule 5	Sustainable Growth Rate
Schedule 6	CAPM
Schedule 7	Empirical CAPM
Schedule 8	Risk Premium
Schedule 9	Expected Earnings Approach

Q110. ARE THE FACTORS YOU DISCUSSED EARLIER THAT DISTINGUISH NORTHWESTERN FROM THE PROXY GROUP ALSO RELEVANT DURING THE ANALYSIS PERIOD CORRESPONDING WITH THE TRUE UP?

A110. Yes. The regulatory mechanisms approved for the proxy group of gas utilities at year-end 2013 are summarized in Schedule 1 to Exhibit__(AMM-12). While the LRAM was repealed effective November 30, 2015, the utilities in the proxy group

nevertheless operated under a considerably broader range of regulatory adjustment mechanisms during the True Up period as compared with NorthWestern, and benefited from revenue decoupling, weather normalization, infrastructure cost recovery trackers, and a variety of other provisions. Meanwhile, as illustrated in Figure 1, during the period covered by the True Up, NorthWestern experienced a chronic shortfall between its earned returns and its authorized ROE. As discussed earlier, the consistent inability to actually earn the allowed return due to attrition is a relevant consideration in evaluating a fair ROE for NorthWestern. In addition, consistent with Table 3 for the prospective period, Table 7 below illustrates that, on balance, investors would have viewed NorthWestern as riskier than the proxy group of gas utilities that was used to estimate the cost of equity:

TABLE 7
COMPARISON OF RISK INDICATORS
TRUE UP PERIOD

	S&P	Moody's	Value Line		
Company	**Credit Rating**	**Issuer Rating**	**Safety Rank**	**Financial Strength**	**Beta**
Gas Group	A-	A2	2	A	0.77
NorthWestern Corp.	BBB	A3	3	B+	0.70

Accordingly, these factors continue to support an upward adjustment from the cost of equity for the proxy group in evaluating a fair ROE for NorthWestern.

Q111. WHAT ROE DO YOU RECOMMEND FOR PURPOSES OF THE NATURAL GAS PRODUCTION ASSETS TRUE UP?

A111. I recommend an ROE of 10.65% in connection with the Company's Natural Gas Production Assets - True Up. Based on my evaluation, I determined that:

- Considering the results of the analyses presented in Exhibit__(AMM-12), and giving less weight to extremes at the high and low ends of the range, I concluded that a contemporaneous

ROE at mid-2014 for a regulated gas utility would fall in the 9.8% to 11.0% range, with a midpoint estimate of 10.4%;

- Considering NorthWestern's higher risks relative to the proxy group, its lack of comparable adjustment mechanisms, and attrition that was ongoing over the period covered by the True Up, an upward adjustment to the Company's cost of equity of 25 basis points is warranted;
- After adding a conservative adjustment of 25 basis points to the 10.4% cost of equity midpoint for the proxy group to account for these factors, my recommended ROE for the Company is 10.65% for purposes of the Natural Gas Production Assets True Up.

Q112. NORTHWESTERN PROPOSES THE USE OF 10.00% AND 9.8% ROES FOR THE NATURAL GAS PRODUCTION ASSETS TRUE-UP. WHAT IS YOUR CONCLUSION REGARDING THE REASONABLENESS OF THE COMPANY'S ROE REQUEST?

A112. As discussed in the testimony of Mr. Rausch, NorthWestern is proposing to use ROEs for purposes of the True Up corresponding to those used by the Company in its evaluation models for the asset purchases.[54] Based on the results of my analyses, I determined that the ROEs proposed by NorthWestern for the True Up fall at the low end of my recommended range of reasonableness of 9.8% to 11.0%, and well below the 10.4% midpoint ROE for the proxy group. Considering the additional risks associated with the Company, the results of my analyses indicate that the 10.00% and 9.80% ROEs proposed by NorthWestern for the Natural Gas Production Assets True Up are conservative.

Q113. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS CASE?

A113. Yes, it does.

[54] As Mr. Rausch explains, these values correspond to the most recent ROEs authorized by the MPSC at the time of the respective asset acquisitions.

EXHIBIT__(AMM-1)

QUALIFICATIONS OF ADRIEN M. MCKENZIE

Q. WHAT IS THE PURPOSE OF THIS EXHIBIT?

A. This exhibit describes my background and experience and contains the details of my qualifications.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received B.A. and M.B.A. degrees with a major in finance from The University of Texas at Austin, and hold the Chartered Financial Analyst (CFA®) designation. Since joining FINCAP in 1984, I have participated in consulting assignments involving a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation. I have extensive experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. I have personally sponsored direct and rebuttal testimony concerning the rate of return on equity ("ROE") in proceedings filed with the Federal Energy Regulatory Commission ("FERC"), the Regulatory Commission of Alaska, the Colorado Public Utilities Commission, the Hawaii Public Utilities Commission, the Idaho Public Utilities Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the Kansas State Corporation Commission, the Kentucky Public Service Commission, the Maryland Public Service Commission, the Montana Public Service Commission, the Nebraska Public Service Commission, the Ohio Public Utilities Commission, the Oregon Public Utilities Commission, the South Dakota Public Utilities Commission, the Virginia State Corporation Commission, the Washington Utilities and

Transportation Commission, the West Virginia Public Service Commission, and the Wyoming Public Service Commission. My testimony addressed the establishment of risk-comparable proxy groups, the application of alternative quantitative methods, and the consideration of regulatory standards and policy objectives in establishing a fair ROE for regulated electric and gas utility operations. In connection with these assignments, my responsibilities have included critically evaluating the positions of other parties and preparation of rebuttal testimony, representing clients in settlement negotiations and hearings, and assisting in the preparation of legal briefs.

In addition, over the course of my career I have worked with Dr. William Avera to prepare prefiled direct and rebuttal testimony in over 250 regulatory proceedings before FERC, the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies in over 30 states.[1] Prior to joining FINCAP, I was employed by an oil and gas firm and was responsible for operations and accounting. A resume containing the details of my qualifications and experience is attached below.

[1] This testimony was sponsored by Dr. William Avera, who is President of FINCAP, Inc.

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Summary of Qualifications

Adrien McKenzie has an MBA in finance from the University of Texas at Austin and holds the Chartered Financial Analyst (CFA) designation. He has over 25 years experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. Assignments have included a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation.

Employment

Vice President, FINCAP, Inc. (June 1984 to June 1987) (April 1988 to present)	Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included rate of return, revenue requirements, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Develop cost of capital analyses using alternative market models for electric, gas, and telephone utilities. Prepare pre-filed direct and rebuttal testimony, participate in settlement negotiations, respond to interrogatories, evaluate opposition testimony, and assist in the areas of cross-examination and the preparations of legal briefs. Other assignments have involved preparation of technical reports, valuations, estimation of damages, industry studies, and various economic analyses in support of litigation.
Manager, McKenzie Energy Company (Jan. 1981 to May. 1984)	Responsible for operations and accounting for firm engaged in the management of working interests in oil and gas properties.

Education

M.B.A., Finance, University of Texas at Austin (Sep. 1982 to May. 1984)	Program included coursework in corporate finance, accounting, financial modeling, and statistics. Received Dean's Award for Academic Excellence and Good Neighbor Scholarship. Professional Report: *The Impact of Construction Expenditures on Investor-Owned Electric Utilities*
B.B.A., Finance, University of Texas at Austin (Jan. 1981 to May 1982)	Electives included capital market theory, portfolio management, and international economics and finance. Elected to Beta Gamma Sigma business honor society. Dean's List 1981-1982.
Simon Fraser University, Vancouver, Canada and University of Hawaii at Manoa, Honolulu, Hawaii (Jan. 1979 to Dec 1980)	Coursework in accounting, finance, economics, and liberal arts.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1990.

Member – CFA Institute.

Bibliography

"A Profile of State Regulatory Commissions," A Special Report by the Electricity Consumers Resource Council (ELCON), Summer 1991.

"The Impact of Regulatory Climate on Utility Capital Costs: An Alternative Test," with Bruce H. Fairchild, *Public Utilities Fortnightly* (May 25, 1989).

Presentations

"ROE at FERC: Issues and Methods," *Expert Briefing on Parallels in ROE Issues between AER, ERA, and FERC*, Jones Day (Sydney, Melbourne, and Perth, Australia) (April 15, 2014).

Cost of Capital Working Group eforum, Edison Electric Institute (April 24, 2012).

"Cost-of-Service Studies and Rate Design," General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

Representative Assignments

Mr. McKenzie has prepared and supported prefiled testimony submitted in over 250 regulatory proceedings. In addition to filings before regulators in over thirty state jurisdictions, Mr. McKenzie has considerable expertise in preparing expert analyses and testimony before the Federal Energy Regulatory Commission ("FERC") on the issue of ROE, and has broad experience in applying and evaluating the results of quantitative methods to estimate a fair ROE, including discounted cash flow approaches, the Capital Asset Pricing Model, risk premium methods, and other quantitative benchmarks. Other representative assignments have included the application of econometric models to analyze the impact of anti-competitive behavior and estimate lost profits; development of explanatory models for nuclear plant capital costs in connection with prudency reviews; and the analysis of avoided cost pricing for cogenerated power.

GAS GROUP

	Company	Mechanism
1	Atmos Energy Corp.	
	Colorado	PGA, ICR
	Kansas	PGA, BDR, ICR, WNA, PCR
	Kentucky	PGA, BDR, ICR, WNA, PBR
	Louisiana	PGA, FRP, ICR, WNA
	Mississippi	PGA, FRP, ICR, WNA, PBR, PCR
	Tennessee	PGA, BDR, FRP, WNA, PBR
	Texas	PGA, BDR, FRP, ICR, WNA, PCR
	Virginia	PGA, BDR, ICR, WNA
2	Chesapeake Utilities	
	Delaware	PGA, RDM (pending), Cost tracker for environmental remediation
	Florida	PGA, ICR, Cost tracker for environmental remediation
	Maryland	PGA, WNA, System Improvement Rider, Cost tracker for environmental remediation
3	New Jersey Resources	
	New Jersey	PGA, RDM, ICR, Cost trackers for environmental remediation and energy efficiency programs, WNA, SCR, Societal Benefits Clause
4	Northwest Natural Gas	
	Oregon	PGA, RDM, WNA, ICR, PCR, Cost tracker for environmental remediation
	Washington	PGA, ICR, Cost tracker for environmental remediation
5	South Jersey Industries	
	New Jersey	PGA, RDM, ICR, Cost trackers for environmental remediation and energy efficiency programs, SCR
6	Southwest Gas	
	Arizona	PGA, RDM, WNA, ICR (limited)
	California	PGA, RDM, ICR
	Nevada	PGA, RDM, ICR, BDR
7	Spire Inc.	
	Alabama	PGA, FRP, PBR, WNA, ICR
	Missouri	PGA, ICR, PCR
8	WGL Holdings, Inc.	
	District of Columbia	PGA, ICR, BDR, PCR
	Maryland	PGA, ICR, DSM, RDM, BDR
	Virginia	PGA, RDM, WNA, DSM, ICR, BDR

BDR -- Bad Debt Cost Recovery Rider
DSM -- Demand Side Management / Conservation / Energy Efficiency Adjustment Clause
FRP -- Formula Rate Plan
ICR -- Infrastructure Investment / Renewables Cost Recovery Mechanism
PBR -- Performance Based Rate Program
PCR -- Pension Cost Recovery Mechanism
PGA -- Gas Cost Adjustment Clause
RDM -- Revenue Decoupling Mechanism
SCR -- Storm Cost Recovery Tracker
TAX -- Property / Franchise Tax Recovery Mechanism
TCR -- Transmission Cost Recovery Tracker
WNA -- Weather Normalization Adjustment or other mitigants

Source : 2015 Form 10-K Reports; American Gas Association, "Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: Current List (Aug. 2016); Regulatory Research Associates, "Adjustment Clauses - A State-by-State Overview," *Regulatory Focus* (Aug. 22, 2016).

ROE ANALYSES

Docket No. D2016.9.68
Exhibit__(AMM-3)
Page 1 of 1

SUMMARY OF RESULTS

	Average	Midpoint
DCF		
Value Line	9.7%	9.9%
IBES	9.0%	9.0%
Zacks	8.6%	8.7%
Internal br + sv	9.1%	10.2%
CAPM		
Historical Bond Yield	10.4%	10.5%
Projected Bond Yield	10.7%	10.8%
Empirical CAPM		
Historical Bond Yield	11.0%	11.1%
Projected Bond Yield	11.3%	11.4%
Utility Risk Premium		
Current Bond Yields	10.4%	
Projected Bond Yields	11.2%	
Expected Earnings	11.3%	11.7%
Cost of Equity Recommendation		
Cost of Equity Range	**9.5% -- 10.7%**	
Midpoint	**10.1%**	
Risk Adjustment	**0.25%**	
Recommended ROE	**10.35%**	

CAPITAL STRUCTURE

GAS GROUP

		At Fiscal Year-End 2015 (a)			Value Line Projected (b)		
	Company	Debt	Preferred	Common Equity	Debt	Other	Common Equity
1	Atmos Energy Corp.	43.5%	0.0%	56.5%	45.0%	0.0%	55.0%
2	Chesapeake Utilities	30.7%	0.0%	69.3%	30.0%	0.0%	70.0%
3	New Jersey Resources	43.6%	0.0%	56.4%	41.0%	0.0%	59.0%
4	Northwest Natural Gas	43.5%	0.0%	56.5%	43.0%	0.0%	57.0%
5	South Jersey Industries	50.0%	0.0%	50.0%	48.5%	0.0%	51.5%
6	Southwest Gas Corp.	49.7%	0.0%	50.3%	48.5%	0.0%	51.5%
7	Spire, Inc. (c)	54.1%	0.0%	45.9%	51.5%	0.0%	48.5%
8	WGL Holdings, Inc.	43.3%	1.3%	55.5%	48.0%	1.0%	51.0%
	Average	44.8%	0.2%	55.1%	44.4%	0.1%	55.4%

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (June 3, 2016).
(c) On April 28, 2016, The Laclede Group changed its name to Spire Inc.

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	Atmos Energy Corp.	$ 75.41	$ 1.77	2.3%
2	Chesapeake Utilities	$ 59.96	$ 1.26	2.1%
3	New Jersey Resources	$ 36.38	$ 0.96	2.6%
4	Northwest Natural Gas	$ 58.91	$ 1.87	3.2%
5	South Jersey Industries	$ 29.79	$ 1.10	3.7%
6	Southwest Gas Corp.	$ 73.13	$ 1.80	2.5%
7	Spire Inc.	$ 66.36	$ 1.96	3.0%
8	WGL Holdings, Inc.	$ 67.25	$ 1.95	2.9%
	Average			2.8%

(a) Average of closing prices for 30 trading days ended July 1, 2016.

(b) The Value Line Investment Survey, *Summary & Index* (July 1, 2016).

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth			br+sv
	Company	V Line	IBES	Zacks	Growth
1	Atmos Energy Corp.	6.0%	7.0%	6.6%	10.2%
2	Chesapeake Utilities	8.5%	3.0%	NA	17.7%
3	New Jersey Resources	1.5%	6.5%	6.5%	5.6%
4	Northwest Natural Gas	7.0%	4.0%	4.0%	3.7%
5	South Jersey Industries	3.0%	6.0%	6.0%	4.4%
6	Southwest Gas Corp.	7.0%	4.0%	5.0%	7.0%
7	Spire Inc.	9.0%	4.5%	4.6%	5.6%
8	WGL Holdings, Inc.	5.0%	8.0%	7.3%	5.0%

(a) The Value Line Investment Survey (June 3, 2016).
(b) www.finance.yahoo.com (retrieved July 7, 2016).
(c) www.zacks.com (retrieved July 7, 2016).
(d) See Exhibit__(AMM-6).

DCF COST OF EQUITY ESTIMATES

	Company	(a) Earnings Growth V Line	(a) Earnings Growth IBES	(a) Earnings Growth Zacks	(a) br+sv Growth
1	Atmos Energy Corp.	8.3%	9.3%	8.9%	12.5%
2	Chesapeake Utilities	10.6%	5.1%	NA	19.8%
3	New Jersey Resources	4.1%	9.1%	9.1%	8.2%
4	Northwest Natural Gas	10.2%	7.2%	7.2%	6.9%
5	South Jersey Industries	6.7%	9.7%	9.7%	8.1%
6	Southwest Gas Corp.	9.5%	6.5%	7.5%	9.5%
7	Spire Inc.	12.0%	7.5%	7.6%	8.5%
8	WGL Holdings, Inc.	7.9%	10.9%	10.2%	7.9%
	Average (b)	**9.7%**	**9.0%**	**8.6%**	**9.1%**
	Midpoint (c)	**9.9%**	**9.0%**	**8.7%**	**10.2%**

(a) Sum of dividend yield (Exhibit__(AMM-5), p. 1) and respective growth rate (Exhibit__(AMM-5), p. 2).

(b) Excludes highlighted figures.

(c) Average of low and high values.

SUSTAINABLE GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
			2020				Adjustment			"sv" Factor			
	Company	EPS	DPS	BVPS	b	r	Factor	Adjusted r	br	s	v	sv	br + sv
1	Atmos Energy Corp.	$4.00	$2.15	$36.65	46.3%	10.9%	1.0321	11.3%	5.2%	0.0837	0.5928	4.96%	10.2%
2	Chesapeake Utilities	$4.00	$1.50	$30.45	62.5%	13.1%	1.0530	13.8%	8.6%	0.1457	0.6194	9.02%	17.7%
3	New Jersey Resources	$1.95	$1.02	$17.00	47.7%	11.5%	1.0264	11.8%	5.6%	(0.0007)	0.3818	-0.03%	5.6%
4	Northwest Natural Gas	$3.15	$2.05	$32.85	34.9%	9.6%	1.0159	9.7%	3.4%	0.0069	0.4027	0.28%	3.7%
5	South Jersey Industries	$1.80	$1.40	$18.80	22.2%	9.6%	1.0430	10.0%	2.2%	0.0586	0.3733	2.19%	4.4%
6	Southwest Gas Corp.	$4.50	$2.40	$38.45	46.7%	11.7%	1.0231	12.0%	5.6%	0.0330	0.4304	1.42%	7.0%
7	Spire Inc.	$4.20	$2.20	$44.45	47.6%	9.4%	1.0304	9.7%	4.6%	0.0300	0.3162	0.95%	5.6%
8	WGL Holdings, Inc.	$3.55	$2.03	$31.80	42.8%	11.2%	1.0247	11.4%	4.9%	0.0015	0.4218	0.06%	5.0%

SUSTAINABLE GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
			2015			2020		Chg		2020 Price				Common Shares	
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2015	2020	Growth
1	Atmos Energy Corp.	56.5%	$5,650	$3,192	55.0%	$8,000	$4,400	6.6%	$100.00	$80.00	$90.00	2.456	101.48	120.00	3.41%
2	Chesapeake Utilities	70.6%	$508	$358	70.0%	$870	$609	11.2%	$90.00	$70.00	$80.00	2.627	15.27	20.00	5.55%
3	New Jersey Resources	56.8%	$1,951	$1,108	59.0%	$2,445	$1,443	5.4%	$30.00	$25.00	$27.50	1.618	85.19	85.00	-0.04%
4	Northwest Natural Gas	57.5%	$1,358	$781	57.0%	$1,605	$915	3.2%	$60.00	$50.00	$55.00	1.674	27.43	28.00	0.41%
5	South Jersey Industries	50.8%	$2,044	$1,038	51.5%	$3,100	$1,597	9.0%	$35.00	$25.00	$30.00	1.596	70.97	85.00	3.67%
6	Southwest Gas Corp.	50.7%	$3,144	$1,594	51.5%	$3,900	$2,009	4.7%	$80.00	$55.00	$67.50	1.756	47.38	52.00	1.88%
7	Spire Inc.	47.0%	$3,345	$1,572	48.5%	$4,395	$2,132	6.3%	$75.00	$55.00	$65.00	1.462	43.36	48.00	2.05%
8	WGL Holdings, Inc.	56.1%	$2,216	$1,243	51.0%	$3,120	$1,591	5.1%	$60.00	$50.00	$55.00	1.730	49.78	50.00	0.09%

(a) The Value Line Investment Survey (June 3, 2016).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2020 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2020 BVPS.

CURRENT BOND YIELD

	Company	(a) Market Return (R_m) Div Yield	(b) Market Return (R_m) Proj. Growth	Market Return (R_m) Cost of Equity	(c) Risk-Free Rate	Risk Premium	(d) Beta	Unadjusted K_e	(e) Market Cap	(f) Size Adjustment	Size Adjusted K_e
1	Atmos Energy Corp.	2.6%	9.0%	11.6%	2.6%	9.0%	0.75	9.4%	$8,312	0.86%	10.2%
2	Chesapeake Utilities	2.6%	9.0%	11.6%	2.6%	9.0%	0.60	8.0%	$1,013	1.62%	9.6%
3	New Jersey Resources	2.6%	9.0%	11.6%	2.6%	9.0%	0.80	9.8%	$3,314	0.99%	10.8%
4	Northwest Natural Gas	2.6%	9.0%	11.6%	2.6%	9.0%	0.65	8.5%	$1,782	1.63%	10.1%
5	South Jersey Industries	2.6%	9.0%	11.6%	2.6%	9.0%	0.80	9.8%	$2,258	1.49%	11.3%
6	Southwest Gas Corp.	2.6%	9.0%	11.6%	2.6%	9.0%	0.75	9.4%	$3,736	0.99%	10.3%
7	Spire Inc.	2.6%	9.0%	11.6%	2.6%	9.0%	0.70	8.9%	$3,074	1.49%	10.4%
8	WGL Holdings, Inc.	2.6%	9.0%	11.6%	2.6%	9.0%	0.75	9.4%	$3,563	0.99%	10.3%
	Average							**9.1%**			**10.4%**
	Midpoint (g)							**8.9%**			**10.5%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (Jun. 9, 2016).
(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Jun. 9, 2016). and www.valueline.com (Jun. 9, 2016).
(c) Average yield on 30-year Treasury bonds for the six-months ending June 2016 based on data from the Federal Reserve at http://www.federalreserve.gov/releases/h15/data.htm.
(d) The Value Line Investment Survey (June 3, 2015).
(e) www.valueline.com (retrieved July 7, 2016).
(f) Duff & Phelps, "2016 Valuation Handbook - Guide to Cost of Capital," John Wiley & Sons (2016) at Table 7.3.
(g) Average of low and high values.

PROJECTED BOND YIELD

		(a)	(b)		(c)		(d)		(e)	(f)	
		Market Return (R_m)									Size
	Company	Div Yield	Proj. Growth	Cost of Equity	Risk-Free Rate	Risk Premium	Beta	Unadjusted K_e	Market Cap	Size Adjustment	Adjusted K_e
1	Atmos Energy Corp.	2.6%	9.0%	11.6%	3.8%	7.8%	0.75	9.7%	$8,312	0.86%	10.5%
2	Chesapeake Utilities	2.6%	9.0%	11.6%	3.8%	7.8%	0.60	8.5%	$1,013	1.62%	10.1%
3	New Jersey Resources	2.6%	9.0%	11.6%	3.8%	7.8%	0.80	10.0%	$3,314	0.99%	11.0%
4	Northwest Natural Gas	2.6%	9.0%	11.6%	3.8%	7.8%	0.65	8.9%	$1,782	1.63%	10.5%
5	South Jersey Industries	2.6%	9.0%	11.6%	3.8%	7.8%	0.80	10.0%	$2,258	1.49%	11.5%
6	Southwest Gas Corp.	2.6%	9.0%	11.6%	3.8%	7.8%	0.75	9.7%	$3,736	0.99%	10.6%
7	Spire Inc.	2.6%	9.0%	11.6%	3.8%	7.8%	0.70	9.3%	$3,074	1.49%	10.8%
8	WGL Holdings, Inc.	2.6%	9.0%	11.6%	3.8%	7.8%	0.75	9.7%	$3,563	0.99%	10.6%
	Average							9.5%			**10.7%**
	Midpoint (g)							9.3%			**10.8%**

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(c) Average projected 30-year Treasury bond yield for 2017-2021 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Jun. 3, 2016); IHS Global Insight (Apr. 6 & Jun. 27, 2016); & Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 35, No. 6 (Jun. 1, 2016).
(d) The Value Line Investment Survey (June 3, 2015).
(e) www.valueline.com (retrieved July 7, 2016).
(f) Duff & Phelps, "2016 Valuation Handbook - Guide to Cost of Capital," John Wiley & Sons (2016) at Table 7.3.
(g) Average of low and high values.

CURRENT BOND YIELD

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP				Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	Total RP	K_e	Cap	Adjustment	K_e
1	Atmos Energy Corp.	2.6%	9.0%	11.6%	2.6%	9.0%	25%	2.3%	0.75	75%	5.1%	7.3%	9.9%	$8,312	0.86%	10.8%
2	Chesapeake Utilities	2.6%	9.0%	11.6%	2.6%	9.0%	25%	2.3%	0.60	75%	4.1%	6.3%	8.9%	$1,013	1.62%	10.5%
3	New Jersey Resources	2.6%	9.0%	11.6%	2.6%	9.0%	25%	2.3%	0.80	75%	5.4%	7.7%	10.3%	$3,314	0.99%	11.2%
4	Northwest Natural Gas	2.6%	9.0%	11.6%	2.6%	9.0%	25%	2.3%	0.65	75%	4.4%	6.6%	9.2%	$1,782	1.63%	10.9%
5	South Jersey Industries	2.6%	9.0%	11.6%	2.6%	9.0%	25%	2.3%	0.80	75%	5.4%	7.7%	10.3%	$2,258	1.49%	11.7%
6	Southwest Gas Corp.	2.6%	9.0%	11.6%	2.6%	9.0%	25%	2.3%	0.75	75%	5.1%	7.3%	9.9%	$3,736	0.99%	10.9%
7	Spire Inc.	2.6%	9.0%	11.6%	2.6%	9.0%	25%	2.3%	0.70	75%	4.7%	7.0%	9.6%	$3,074	1.49%	11.1%
8	WGL Holdings, Inc.	2.6%	9.0%	11.6%	2.6%	9.0%	25%	2.3%	0.75	75%	5.1%	7.3%	9.9%	$3,563	0.99%	10.9%
	Average												9.7%			**11.0%**
	Midpoint (h)												9.6%			**11.1%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (Jun. 9, 2016).

(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Jun. 9, 2016). and www.valueline.com (Jun. 9, 2016).

(c) Average yield on 30-year Treasury bonds for the six-months ending June 2016 based on data from the Federal Reserve at http://www.federalreserve.gov/releases/h15/data.htm.

(d) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).

(e) The Value Line Investment Survey (June 3, 2015).

(f) www.valueline.com (retrieved July 7, 2016).

(g) Duff & Phelps, "2016 Valuation Handbook - Guide to Cost of Capital," John Wiley & Sons (2016) at Table 7.3.

(h) Average of low and high values.

PROJECTED BOND YIELD

		(a)	(b)		(c)		(d)		(e)	(d)				(f)	(g)	
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP				Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	Total RP	K_e	Cap	Adjustment	K_e
1	Atmos Energy Corp.	2.6%	9.0%	11.6%	3.8%	7.8%	25%	1.9%	0.75	75%	4.4%	6.3%	10.1%	$8,312	0.86%	11.0%
2	Chesapeake Utilities	2.6%	9.0%	11.6%	3.8%	7.8%	25%	1.9%	0.60	75%	3.5%	5.4%	9.3%	$1,013	1.62%	10.9%
3	New Jersey Resources	2.6%	9.0%	11.6%	3.8%	7.8%	25%	1.9%	0.80	75%	4.7%	6.6%	10.4%	$3,314	0.99%	11.4%
4	Northwest Natural Gas	2.6%	9.0%	11.6%	3.8%	7.8%	25%	1.9%	0.65	75%	3.8%	5.7%	9.6%	$1,782	1.63%	11.2%
5	South Jersey Industries	2.6%	9.0%	11.6%	3.8%	7.8%	25%	1.9%	0.80	75%	4.7%	6.6%	10.4%	$2,258	1.49%	11.9%
6	Southwest Gas Corp.	2.6%	9.0%	11.6%	3.8%	7.8%	25%	1.9%	0.75	75%	4.4%	6.3%	10.1%	$3,736	0.99%	11.1%
7	Spire Inc.	2.6%	9.0%	11.6%	3.8%	7.8%	25%	1.9%	0.70	75%	4.1%	6.0%	9.9%	$3,074	1.49%	11.3%
8	WGL Holdings, Inc.	2.6%	9.0%	11.6%	3.8%	7.8%	25%	1.9%	0.75	75%	4.4%	6.3%	10.1%	$3,563	0.99%	11.1%
	Average												**10.0%**			**11.3%**
	Midpoint (h)												**9.9%**			**11.4%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from www.valueline.com (Jun. 9, 2016).

(b) Average of weighted average earnings growth rates from IBES and Value Line Investment Survey for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Jun. 9, 2016). and www.valueline.com (Jun. 9, 2016).

(c) Average projected 30-year Treasury bond yield for 2017-2021 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Jun. 3, 2016); IHS Global Insight (Apr. 6 & Jun. 27, 2016); & Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 35, No. 6 (Jun. 1, 2016).

(d) Morin, Roger A., "New Regulatory Finance," Public Utilities Reports, Inc. at 190 (2006).

(e) The Value Line Investment Survey (June 3, 2015).

(f) www.valueline.com (retrieved July 7, 2016).

(g) Duff & Phelps, "2016 Valuation Handbook - Guide to Cost of Capital," John Wiley & Sons (2016) at Table 7.3.

(h) Average of low and high values.

CURRENT BOND YIELDS

Current Equity Risk Premium		
(a)	Avg. Yield over Study Period	8.31%
(b)	Single-A Utility Bond Yield	4.04%
	Change in Bond Yield	-4.27%
(c)	Risk Premium/Interest Rate Relationship	-0.4628
	Adjustment to Average Risk Premium	1.98%
(a)	Average Risk Premium over Study Period	3.43%
	Adjusted Risk Premium	**5.41%**
Implied Cost of Equity		
(b)	Triple-B Utility Bond Yield	4.95%
	Adjusted Equity Risk Premium	5.41%
	Risk Premium Cost of Equity	**10.36%**

(a) Exhibit__(AMM-9), page 3.
(b) Average bond yield for six-months ending June 2016 based on data from Moody's Investors Service at www.credittrends.com.
(c) Exhibit__(AMM-9), page 4.

PROJECTED BOND YIELDS

	Current Equity Risk Premium	
(a)	Avg. Yield over Study Period	8.31%
(b)	Single-A Utility Bond Yield 2017-21	5.68%
	Change in Bond Yield	-2.64%
(c)	Risk Premium/Interest Rate Relationship	-0.4628
	Adjustment to Average Risk Premium	1.22%
(a)	Average Risk Premium over Study Period	3.43%
	Adjusted Risk Premium	**4.65%**
	Implied Cost of Equity	
(b)	Triple-B Utility Bond Yield 2017-21	6.59%
	Adjusted Equity Risk Premium	4.65%
	Risk Premium Cost of Equity	**11.24%**

(a) Exhibit__(AMM-9), page 3.
(b) Based on data from Wolters Kluwer, Blue Chip Financial Forecasts, Vol. 35, No. 6 (Jun. 1, 2016); Moody's Investors Service at www.credittrends.com.
(c) Exhibit__(AMM-9), page 4.

AUTHORIZED RETURNS

Year	Qtr.		(a) Allowed ROE	(b) Single-A Utility Bond Yield	Risk Premium
1980	1		13.45%	13.49%	-0.04%
	2		14.38%	12.87%	1.51%
	3		13.87%	12.88%	0.99%
	4		14.35%	14.11%	0.24%
1981	1		14.69%	14.77%	-0.08%
	2		14.61%	15.82%	-1.21%
	3		14.86%	16.65%	-1.79%
	4		15.70%	16.57%	-0.87%
1982	1		15.55%	16.72%	-1.17%
	2		15.62%	16.26%	-0.64%
	3		15.72%	15.88%	-0.16%
	4		15.62%	14.56%	1.06%
1983	1		15.41%	14.15%	1.26%
	2		14.84%	13.58%	1.26%
	3		15.24%	13.52%	1.72%
	4		15.41%	13.38%	2.03%
1984	1		15.39%	13.56%	1.83%
	2		15.07%	14.72%	0.35%
	3		15.37%	14.47%	0.90%
	4		15.33%	13.38%	1.95%
1985	1		15.03%	13.31%	1.72%
	2		15.44%	12.95%	2.49%
	3		14.64%	12.11%	2.53%
	4		14.44%	11.49%	2.95%
1986	1		14.05%	10.18%	3.87%
	2		13.28%	9.41%	3.87%
	3		13.09%	9.39%	3.70%
	4		13.62%	9.31%	4.31%
1987	1		12.61%	8.96%	3.65%
	2		13.13%	9.77%	3.36%
	3		12.56%	10.61%	1.95%
	4		12.73%	11.05%	1.68%
1988	1		12.94%	10.32%	2.62%
	2		12.48%	10.71%	1.77%
	3		12.79%	10.94%	1.85%
	4		12.98%	9.98%	3.00%
1989	1		12.99%	10.13%	2.86%
	2		13.25%	9.94%	3.31%
	3		12.56%	9.53%	3.03%
	4		12.94%	9.50%	3.44%
1990	1		12.60%	9.72%	2.88%
	2		12.81%	9.91%	2.90%
	3		12.34%	9.93%	2.41%
	4		12.77%	9.89%	2.88%
1991	1		12.69%	9.58%	3.11%
	2		12.53%	9.50%	3.03%
	3		12.43%	9.33%	3.10%
	4		12.38%	9.02%	3.36%
1992	1		12.42%	8.91%	3.51%
	2		11.98%	8.86%	3.12%
	3		11.87%	8.47%	3.40%
	4		11.94%	8.53%	3.41%
1993	1		11.75%	8.07%	3.68%
	2		11.71%	7.81%	3.90%
	3		11.39%	7.28%	4.11%
	4		11.15%	7.22%	3.93%
1994	1		11.12%	7.55%	3.57%
	2		10.81%	8.29%	2.52%
	3		10.95%	8.51%	2.44%
	4	(c)	11.64%	8.87%	2.77%
1995	2		11.00%	7.93%	3.07%
	3		11.07%	7.72%	3.35%
	4		11.56%	7.37%	4.19%
1996	1		11.45%	7.44%	4.01%
	2		10.88%	7.98%	2.90%
	3		11.25%	7.96%	3.29%
	4		11.32%	7.62%	3.70%
1997	1		11.31%	7.76%	3.55%
	2		11.70%	7.88%	3.82%
	3		12.00%	7.49%	4.51%
	4	(c)	11.01%	7.25%	3.76%
1998	2		11.37%	7.12%	4.25%
	3		11.41%	6.99%	4.42%
	4		11.69%	6.97%	4.72%
1999	1		10.82%	7.11%	3.71%
	2	(c)	10.82%	7.48%	3.34%
	4		10.33%	8.05%	2.28%
2000	1		10.71%	8.29%	2.42%
	2		11.08%	8.45%	2.63%
	3		11.33%	8.25%	3.08%
	4		12.50%	8.03%	4.47%
2001	1		11.16%	7.74%	3.42%
	2	(c)	10.75%	7.93%	2.82%
	4		10.65%	7.68%	2.97%
2002	1		10.67%	7.65%	3.02%
	2		11.64%	7.50%	4.14%
	3		11.50%	7.19%	4.31%
	4		10.78%	7.15%	3.63%
2003	1		11.38%	6.93%	4.45%
	2		11.36%	6.40%	4.96%
	3		10.61%	6.64%	3.97%
	4		10.84%	6.35%	4.49%
2004	1		11.10%	6.09%	5.01%
	2		10.25%	6.48%	3.77%
	3		10.37%	6.13%	4.24%
	4		10.66%	5.94%	4.72%
2005	1		10.65%	5.74%	4.91%
	2		10.52%	5.52%	5.00%
	3		10.47%	5.51%	4.96%
	4		10.40%	5.82%	4.58%
2006	1		10.63%	5.85%	4.78%
	2		10.50%	6.37%	4.13%
	3		10.45%	6.19%	4.26%
	4		10.14%	5.86%	4.28%
2007	1		10.44%	5.90%	4.54%
	2		10.12%	6.09%	4.03%
	3		10.03%	6.22%	3.81%
	4		10.27%	6.08%	4.19%
2008	1		10.38%	6.15%	4.23%
	2		10.17%	6.32%	3.85%
	3		10.49%	6.42%	4.07%
	4		10.34%	7.23%	3.11%
2009	1		10.24%	6.37%	3.87%
	2		10.11%	6.39%	3.72%
	3		9.88%	5.74%	4.14%
	4		10.27%	5.66%	4.61%
2010	1		10.24%	5.83%	4.41%
	2		9.99%	5.61%	4.38%
	3		9.93%	5.09%	4.84%
	4		10.09%	5.34%	4.75%
2011	1		10.10%	5.60%	4.50%
	2		9.85%	5.38%	4.47%
	3		9.65%	4.81%	4.84%
	4		9.88%	4.37%	5.51%
2012	1		9.63%	4.39%	5.24%
	2		9.83%	4.23%	5.60%
	3		9.75%	3.98%	5.77%
	4		10.07%	3.93%	6.14%
2013	1		9.57%	4.18%	5.39%
	2		9.47%	4.23%	5.24%
	3		9.60%	4.74%	4.86%
	4		9.83%	4.76%	5.07%
2014	1		9.54%	4.56%	4.98%
	2		9.84%	4.32%	5.52%
	3		9.45%	4.20%	5.25%
	4		10.28%	4.03%	6.25%
2015	1		9.47%	3.66%	5.81%
	2		9.43%	4.13%	5.30%
	3		9.75%	4.35%	5.40%
	4		9.68%	4.35%	5.33%
2016	1		9.48%	4.18%	5.30%
	2		9.42%	3.90%	5.52%
Average			11.75%	8.31%	3.43%

(a) Regulatory Research Associates, Inc., Major Rate Case Decisions, (July 15, 2016, Jan. 14, 2016, Jan. 7, 2011, Apr. 5, 2004, Jan. 21, 1998, July 12, 1991, and Jan. 16, 1990).

(b) Moody's Investors Service.

(c) No decisions reported for following quarter.

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.945191
R Square	0.893386
Adjusted R Square	0.892625
Standard Error	0.005205
Observations	142.000000

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1.000000	0.031779	0.031779	1173.150966	0.000000
Residual	140.000000	0.003792	0.000027		
Total	141.000000	0.035572			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.072791	0.001205	60.392855	0.000000	0.070408	0.075174	0.070408	0.075174
X Variable 1	-0.462752	0.013510	-34.251291	0.000000	-0.489463	-0.436041	-0.489463	-0.436041

EXPECTED EARNINGS APPROACH

GAS GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	Atmos Energy Corp.	11.0%	1.0321	11.4%
2	Chesapeake Utilities	13.0%	1.0530	13.7%
3	New Jersey Resources	11.5%	1.0264	11.8%
4	Northwest Natural Gas	9.5%	1.0159	9.7%
5	South Jersey Industries	9.5%	1.0430	9.9%
6	Southwest Gas Corp.	12.5%	1.0231	12.8%
7	Spire Inc.	9.5%	1.0304	9.8%
8	WGL Holdings, Inc.	11.0%	1.0247	11.3%
	Average			11.3%
	Midpoint (d)			11.7%

(a) The Value Line Investment Survey (June 3, 2016).
(b) Adjustment to convert year-end return to an average rate of return from Exhibit__(AMM-6).
(c) (a) x (b).
(d) Average of low and high values.

DCF MODEL - NON-UTILITY GROUP

DIVIDEND YIELD

	Company	Industry Group	(a) Price	(b) Dividends	Yield
1	Church & Dwight	Household Products	$ 98.13	$ 1.42	1.4%
2	Coca-Cola	Beverage	$ 45.02	$ 1.40	3.1%
3	Colgate-Palmolive	Household Products	$ 71.39	$ 1.58	2.2%
4	ConAgra Foods	Food Processing	$ 45.84	$ 1.00	2.2%
5	Costco Wholesale	Retail Store	$ 149.22	$ 1.80	1.2%
6	Everest Re Group Ltd.	Reinsurance	$ 179.17	$ 4.80	2.7%
7	Gen'l Mills	Food Processing	$ 63.74	$ 1.84	2.9%
8	Hormel Foods	Food Processing	$ 36.01	$ 0.62	1.7%
9	Johnson & Johnson	Medical Supplies	$ 114.44	$ 3.25	2.8%
10	Kellogg	Food Processing	$ 75.76	$ 2.04	2.7%
11	Kimberly-Clark	Household Products	$ 128.99	$ 3.68	2.9%
12	Lilly (Eli)	Drug Industry	$ 75.11	$ 2.04	2.7%
13	McDonald's Corp.	Restaurant	$ 124.66	$ 3.60	2.9%
14	PepsiCo, Inc.	Beverage	$ 102.90	$ 3.01	2.9%
15	Procter & Gamble	Household Products	$ 81.90	$ 2.68	3.3%
16	Public Storage	REIT	$ 253.86	$ 7.20	2.8%
17	Smucker (J.M.)	Food Processing	$ 133.05	$ 2.77	2.1%
18	Sysco Corp.	Wholesale Food	$ 49.08	$ 1.26	2.6%
19	Target Corp.	Retail Store	$ 70.34	$ 5.10	7.3%
20	Verizon Com.	Telecommunications	$ 51.19	$ 2.26	4.4%
21	Wal-Mart Stores	Retail Store	$ 69.43	$ 2.00	2.9%
	Average				**2.8%**

(a) Average of closing prices for 30 trading days ended Jun. 17, 2016.
(b) The Value Line Investment Survey, *Summary & Index* (Jun. 10, 2016).

GROWTH RATES

		(a)	(b)	(c)
		Earnings Growth Rates		
	Company	V Line	IBES	Zacks
1	Church & Dwight	7.50%	8.83%	9.64%
2	Coca-Cola	4.00%	4.04%	5.79%
3	Colgate-Palmolive	13.50%	7.33%	7.34%
4	ConAgra Foods	6.00%	6.98%	8.13%
5	Costco Wholesale	9.00%	9.02%	9.87%
6	Everest Re Group Ltd.	2.50%	-7.28%	10.00%
7	Gen'l Mills	5.00%	5.42%	6.82%
8	Hormel Foods	14.00%	9.35%	10.30%
9	Johnson & Johnson	8.50%	6.00%	5.73%
10	Kellogg	5.00%	4.98%	5.78%
11	Kimberly-Clark	10.00%	7.40%	7.26%
12	Lilly (Eli)	9.50%	12.46%	12.48%
13	McDonald's Corp.	6.00%	10.57%	9.70%
14	PepsiCo, Inc.	6.00%	6.50%	7.42%
15	Procter & Gamble	6.50%	6.13%	6.35%
16	Public Storage	NA	7.60%	6.26%
17	Smucker (J.M.)	7.00%	10.56%	8.36%
18	Sysco Corp.	10.50%	10.50%	8.67%
19	Target Corp.	11.00%	9.25%	10.69%
20	Verizon Com.	8.00%	3.18%	4.22%
21	Wal-Mart Stores	1.00%	1.95%	4.34%

(a) The Value Line Investment Survey (Mar. 25, Apr. 8, Apr. 22, Apr. 29, May 20, May 27, & Jun. 17, 2016).

(b) www.finance.yahoo.com (retrieved Jun. 20, 2016).

(c) www.zacks.com (retrieved Jun. 20, 2015).

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)
		Cost of Equity Estimates		
	Company	V Line	IBES	Zacks
1	Church & Dwight	8.9%	10.3%	11.1%
2	Coca-Cola	7.1%	7.1%	8.9%
3	Colgate-Palmolive	15.7%	9.5%	9.6%
4	ConAgra Foods	8.2%	9.2%	10.3%
5	Costco Wholesale	10.2%	10.2%	11.1%
6	Everest Re Group Ltd.	5.2%	-4.6%	12.7%
7	Gen'l Mills	7.9%	8.3%	9.7%
8	Hormel Foods	15.7%	11.1%	12.0%
9	Johnson & Johnson	11.3%	8.8%	8.6%
10	Kellogg	7.7%	7.7%	8.5%
11	Kimberly-Clark	12.9%	10.3%	10.1%
12	Lilly (Eli)	12.2%	15.2%	15.2%
13	McDonald's Corp.	8.9%	13.5%	12.6%
14	PepsiCo, Inc.	8.9%	9.4%	10.3%
15	Procter & Gamble	9.8%	9.4%	9.6%
16	Public Storage	NA	10.4%	9.1%
17	Smucker (J.M.)	9.1%	12.6%	10.4%
18	Sysco Corp.	13.1%	13.1%	11.2%
19	Target Corp.	18.3%	16.5%	17.9%
20	Verizon Com.	12.4%	7.6%	8.6%
21	Wal-Mart Stores	3.9%	4.8%	7.2%
	Average (b)	**10.6%**	**10.5%**	**10.3%**
	Midpoint (c)	**11.4%**	**11.8%**	**11.2%**

(a) Sum of dividend yield (Exhibit__(AMM-11), p. 1) and respective growth rate (Exhibit__(AMM-11), p. 2).

(b) Excludes highlighted figures.

(c) Average of low and high values.

DOCKET NO. D2016.9.68

EXHIBIT__(AMM-12)

SCHEDULES SUPPORTING ROE

FOR

NATURAL GAS PRODUCTION ASSETS TRUE UP

REGULATORY MECHANISMS

GAS GROUP

	Company	Mechanism
1	AGL Resources, Inc.	PGA; RDM; WNA; ICR; DSM; Cost tracker for environmental remediation
2	Atmos Energy Corp.	PGA; WNA; ICR; BDR; Annual rate filing mechanism
3	New Jersey Resources	PGA; RDM; ICR; Cost trackers for environmental remediation and energy efficiency programs
4	NiSource, Inc.	PGA; RDM; WNA; ICR; BDR; Tax rider; Surcharge for conservation and energy efficiency programs; Cost tracker for environmental remediation
5	Northwest Natural Gas	PGA; RDM; WNA; ICR; Cost tracker for environmental remediation
6	Piedmont Natural Gas	PGA; RDM; WNA; ICR; Rate stabilization mechanism to reduce regulatory lag
7	South Jersey Industries	PGA; RDM; ICR; Cost trackers for environmental remediation and energy efficiency programs
8	Southwest Gas	PGA; RDM
9	WGL Holdings, Inc.	PGA; RDM; WNA; ICR; DSM; PCR

BDR -- Bad Debt Cost Recovery Rider
DSM -- Demand Side Management / Conservation Adjustment Clause
ECA -- Environmental and/or Emissions Cost Adjustment Clause
FCA -- Fuel and/or Power Cost Adjustment Clause
ICR -- Infrastructure Investment / Renewables Cost Recovery Mechanism
PCR -- Pension Cost Recovery Mechanism
PGA -- Gas Cost Adjustment Clause
RDM -- Revenue Decoupling Mechanism
SCR - Storm Cost Recovery Tracker
TCR -- Transmission Cost Recovery Tracker
WNC -- Weather Normalization Clause or other mitigants

Source : 2013 Form 10-K Reports

CAPITAL STRUCTURE

GAS GROUP

		At Fiscal Year-End 2013 (a)			Value Line Projected (b)		
	Company	Debt	Preferred	Common Equity	Debt	Other	Common Equity
1	AGL Resources	50.9%	0.0%	49.1%	50.5%	0.0%	49.5%
2	Atmos Energy Corp.	48.8%	0.0%	51.2%	45.0%	0.0%	55.0%
3	New Jersey Resources	39.6%	0.0%	60.4%	30.0%	0.0%	70.0%
4	NiSource, Inc.	58.0%	0.0%	42.0%	60.5%	0.0%	39.5%
5	Northwest Natural Gas	49.7%	0.0%	50.3%	45.5%	0.0%	54.5%
6	Piedmont Natural Gas	51.8%	0.0%	48.2%	46.0%	0.0%	54.0%
7	South Jersey Industries	45.9%	0.0%	54.1%	42.0%	0.0%	58.0%
8	Southwest Gas Corp.	49.6%	0.0%	50.4%	49.5%	0.0%	50.5%
9	WGL Holdings, Inc.	31.2%	1.5%	67.3%	27.5%	1.5%	71.0%
	Average	**47.3%**	**0.2%**	**52.6%**	**44.1%**	**0.2%**	**55.8%**

(a) Company Form 10-K and Annual Reports.
(b) The Value Line Investment Survey (Jun. 6, 2014).

ROE ANALYSES

SUMMARY OF RESULTS

	Average	Midpoint
DCF		
Value Line	10.4%	10.9%
IBES	9.9%	10.4%
Zacks	9.1%	9.5%
Internal br + sv	9.5%	10.2%
CAPM		
Historical Bond Yield	11.8%	11.8%
Projected Bond Yield	12.1%	12.1%
Empirical CAPM		
Historical Bond Yield	12.3%	12.3%
Projected Bond Yield	12.5%	12.4%
Utility Risk Premium		
Current Bond Yields	10.1%	
Projected Bond Yields	11.0%	
Expected Earnings	11.4%	12.5%
Cost of Equity Recommendation		
Cost of Equity Range	**9.8% -- 11.0%**	
Midpoint	**10.4%**	
Risk Adjustment	**0.25%**	
Recommended ROE	**10.65%**	

DCF MODEL - GAS GROUP

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	AGL Resources	$ 53.02	$ 1.96	3.7%
2	Atmos Energy Corp.	$ 50.67	$ 1.51	3.0%
3	New Jersey Resources	$ 51.70	$ 1.68	3.2%
4	NiSource, Inc.	$ 36.81	$ 1.04	2.8%
5	Northwest Natural Gas	$ 44.46	$ 1.84	4.1%
6	Piedmont Natural Gas	$ 35.29	$ 1.28	3.6%
7	South Jersey Industries	$ 56.81	$ 2.00	3.5%
8	Southwest Gas Corp.	$ 53.13	$ 1.48	2.8%
9	WGL Holdings, Inc.	$ 39.74	$ 1.76	4.4%
	Average			3.5%

(a) Average of closing prices for 30 trading days ended Jun. 6, 2014.
(b) The Value Line Investment Survey, *Summary & Index* (Jun. 6, 2014).

DCF MODEL - GAS GROUP

GROWTH RATES

		(a)	(b)	(c)	(d)	(e)
		Earnings Growth				br+sv
	Company	V Line	IBES	Zacks	Reuters	Growth
1	AGL Resources	10.5%	NA	2.0%	4.0%	6.2%
2	Atmos Energy Corp.	7.5%	7.1%	6.7%	7.1%	6.4%
3	New Jersey Resources	5.5%	3.6%	4.0%	3.6%	6.2%
4	NiSource, Inc.	10.5%	10.4%	8.7%	10.4%	6.9%
5	Northwest Natural Gas	6.5%	3.5%	3.7%	3.5%	4.0%
6	Piedmont Natural Gas	4.0%	3.7%	4.0%	3.7%	3.8%
7	South Jersey Industries	8.0%	6.0%	6.0%	NA	9.5%
8	Southwest Gas Corp.	6.0%	2.4%	4.7%	2.4%	7.1%
9	WGL Holdings, Inc.	4.0%	4.9%	5.4%	4.9%	4.3%

(a) The Value Line Investment Survey (Jun. 6, 2014).
(b) www.finance.yahoo.com (retrieved Jun. 16, 2014).
(c) www.zacks.com (retrieved Jun. 16, 2014).
(d) www.reuters.com (retrieved June. 16, 2014).
(e) See Schedule 5.

DCF MODEL - GAS GROUP

DCF COST OF EQUITY ESTIMATES

	Company	(a) Earnings Growth V Line	(a) Earnings Growth IBES	(a) Earnings Growth Zacks	(a) Earnings Growth Reuters	(a) br+sv Growth
1	AGL Resources	14.2%	NA	5.7%	7.7%	9.9%
2	Atmos Energy Corp.	10.5%	10.0%	9.7%	10.0%	9.3%
3	New Jersey Resources	8.7%	6.8%	7.2%	6.8%	9.4%
4	NiSource, Inc.	13.3%	13.2%	11.5%	13.2%	9.8%
5	Northwest Natural Gas	10.6%	7.6%	7.8%	7.6%	8.1%
6	Piedmont Natural Gas	7.6%	7.3%	7.6%	7.3%	7.4%
7	South Jersey Industries	11.5%	9.5%	9.5%	NA	13.0%
8	Southwest Gas Corp.	8.8%	5.1%	7.5%	5.1%	9.8%
9	WGL Holdings, Inc.	8.4%	9.3%	9.8%	9.3%	8.7%
	Average (b)	**10.4%**	**9.9%**	**9.1%**	**9.6%**	**9.5%**
	Midpoint (c)	**10.9%**	**10.4%**	**9.5%**	**10.4%**	**10.2%**

(a) Sum of dividend yield (Schedule 4, p. 1) and respective growth rate (Schedule 4, p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

DCF MODEL - GAS GROUP

SUSTAINABLE GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		----------	2018	----------			Adjustment			--------- "sv" Factor --------			
	Company	EPS	DPS	BVPS	b	r	Factor	Adjusted r	br	s	v	sv	br + sv
1	AGL Resources	$4.30	$2.40	$36.25	44.2%	11.9%	1.0225	12.1%	5.4%	0.0181	0.4423	0.80%	6.2%
2	Atmos Energy Corp.	$3.50	$1.70	$38.90	51.4%	9.0%	1.0470	9.4%	4.8%	0.0470	0.3235	1.52%	6.4%
3	New Jersey Resources	$3.75	$1.76	$30.10	53.1%	12.5%	1.0266	12.8%	6.8%	(0.0141)	0.4267	-0.60%	6.2%
4	NiSource, Inc.	$2.40	$1.20	$19.30	50.0%	12.4%	1.0068	12.5%	6.3%	0.0138	0.4853	0.67%	6.9%
5	Northwest Natural Gas	$3.30	$2.10	$34.20	36.4%	9.6%	1.0250	9.9%	3.6%	0.0108	0.3782	0.41%	4.0%
6	Piedmont Natural Gas	$2.10	$1.43	$19.45	31.9%	10.8%	1.0217	11.0%	3.5%	0.0057	0.4813	0.28%	3.8%
7	South Jersey Industries	$4.80	$2.60	$33.35	45.8%	14.4%	1.0410	15.0%	6.9%	0.0539	0.4869	2.62%	9.5%
8	Southwest Gas Corp.	$4.00	$1.80	$37.00	55.0%	10.8%	1.0265	11.1%	6.1%	0.0247	0.3833	0.95%	7.1%
9	WGL Holdings, Inc.	$3.10	$1.87	$29.90	39.7%	10.4%	1.0194	10.6%	4.2%	0.0017	0.3356	0.06%	4.3%

DCF MODEL - GAS GROUP

SUSTAINABLE GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2013			2018			Chg	2018 Price				Common Shares		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2013	2018	Growth
1	AGL Resources	48.8%	$7,444	$3,633	49.5%	$9,195	$4,552	4.6%	$70.00	$60.00	$65.00	1.793	118.89	125.00	1.01%
2	Atmos Energy Corp.	51.2%	$5,036	$2,578	55.0%	$7,500	$4,125	9.9%	$65.00	$50.00	$57.50	1.478	90.64	106.00	3.18%
3	New Jersey Resources	63.4%	$1,400	$888	70.0%	$1,655	$1,159	5.5%	$60.00	$45.00	$52.50	1.744	41.66	40.00	-0.81%
4	NiSource, Inc.	43.7%	$13,480	$5,891	39.5%	$15,965	$6,306	1.4%	$45.00	$30.00	$37.50	1.943	313.68	325.00	0.71%
5	Northwest Natural Gas	52.4%	$1,434	$751	54.5%	$1,770	$965	5.1%	$60.00	$50.00	$55.00	1.608	27.08	28.00	0.67%
6	Piedmont Natural Gas	50.3%	$2,364	$1,189	54.0%	$2,735	$1,477	4.4%	$45.00	$30.00	$37.50	1.928	74.88	76.00	0.30%
7	South Jersey Industries	54.9%	$1,507	$828	58.0%	$2,150	$1,247	8.5%	$75.00	$55.00	$65.00	1.949	32.72	37.50	2.76%
8	Southwest Gas Corp.	50.6%	$2,794	$1,414	50.5%	$3,650	$1,843	5.5%	$70.00	$50.00	$60.00	1.622	46.36	50.00	1.52%
9	WGL Holdings, Inc.	69.8%	$1,827	$1,275	71.0%	$2,180	$1,548	4.0%	$50.00	$40.00	$45.00	1.505	51.70	52.00	0.12%

(a) The Value Line Investment Survey (Jun. 6, 2014).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2018 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2018 BVPS.

CAPM - CURRENT BOND YIELD

GAS GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Market Return (R_m)									Size
	Company	Div Yield	Proj. Growth	Cost of Equity	Risk-Free Rate	Risk Premium	Beta	Unadjusted K_e	Market Cap	Size Adjustment	Adjusted K_e
1	AGL Resources	2.3%	10.0%	12.3%	3.5%	8.8%	0.80	10.5%	$6,282	0.93%	11.5%
2	Atmos Energy Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	0.80	10.5%	$5,069	1.19%	11.7%
3	New Jersey Resources	2.3%	10.0%	12.3%	3.5%	8.8%	0.75	10.1%	$2,301	1.75%	11.8%
4	NiSource, Inc.	2.3%	10.0%	12.3%	3.5%	8.8%	0.80	10.5%	$11,644	0.80%	11.3%
5	Northwest Natural Gas	2.3%	10.0%	12.3%	3.5%	8.8%	0.70	9.7%	$1,219	1.75%	11.4%
6	Piedmont Natural Gas	2.3%	10.0%	12.3%	3.5%	8.8%	0.75	10.1%	$2,829	1.72%	11.8%
7	South Jersey Industries	2.3%	10.0%	12.3%	3.5%	8.8%	0.80	10.5%	$1,858	1.75%	12.3%
8	Southwest Gas Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	0.80	10.5%	$2,405	1.75%	12.3%
9	WGL Holdings, Inc.	2.3%	10.0%	12.3%	3.5%	8.8%	0.75	10.1%	$2,129	1.75%	11.8%
	Average							**10.3%**			**11.8%**
	Midpoint (k)							**10.1%**			**11.8%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 8, 2014).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 10, 2014).
(c) (a) + (b).
(d) Average yield on 30-year Treasury bonds for the six-months ending Jul. 2014 based on data from the Federal Reserve at http://www.federalreserve.gov/releases/h15/data.htm.
(e) (c) - (d).
(f) The Value Line Investment Survey (Jun. 6, 2014).
(g) (d) + (e) x (f).
(h) www.valueline.com (retrieved Jun. 16, 2014).
(i) *Morningstar*, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).
(j) (g) + (h).
(k) Average of low and high values.

CAPM - PROJECTED BOND YIELD

GAS GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Market Return (R_m)									Size
	Company	Div Yield	Proj. Growth	Cost of Equity	Risk-Free Rate	Risk Premium	Beta	Unadjusted K_e	Market Cap	Size Adjustment	Adjusted K_e
1	AGL Resources	2.3%	10.0%	12.3%	4.7%	7.6%	0.80	10.8%	$6,282	0.93%	11.7%
2	Atmos Energy Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.80	10.8%	$5,069	1.19%	12.0%
3	New Jersey Resources	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.4%	$2,301	1.75%	12.2%
4	NiSource, Inc.	2.3%	10.0%	12.3%	4.7%	7.6%	0.80	10.8%	$11,644	0.80%	11.6%
5	Northwest Natural Gas	2.3%	10.0%	12.3%	4.7%	7.6%	0.70	10.0%	$1,219	1.75%	11.8%
6	Piedmont Natural Gas	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.4%	$2,829	1.72%	12.1%
7	South Jersey Industries	2.3%	10.0%	12.3%	4.7%	7.6%	0.80	10.8%	$1,858	1.75%	12.5%
8	Southwest Gas Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	0.80	10.8%	$2,405	1.75%	12.5%
9	WGL Holdings, Inc.	2.3%	10.0%	12.3%	4.7%	7.6%	0.75	10.4%	$2,129	1.75%	12.2%
	Average							**10.6%**			**12.1%**
	Midpoint (k)							**10.4%**			**12.1%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 8, 2014).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 10, 2014).
(c) (a) + (b).
(d) Average projected 30-year Treasury bond yield for 2015-2018 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (May 23, 2014); IHS Global Insight, U.S. Economic Outlook at 79 (May 2014); & Blue Chip Financial Forecasts, Vol. 32, No. 12 (Dec. 1, 2013).
(e) (c) - (d).
(f) The Value Line Investment Survey (Jun. 6, 2014).
(g) (d) + (e) x (f).
(h) www.valueline.com (retrieved Jun. 27, 2013).
(i) *Morningstar*, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).
(j) (g) + (h).
(k) Average of low and high values.

EMPIRICAL CAPM - CURRENT BOND YIELD

HISTORICAL BOND YIELD

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(f)	(i)		(j)	(k)	(l)	(m)
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP				Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	Total RP	K_e	Cap	Adjustment	K_e
1	AGL Resources	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.80	75%	5.3%	7.5%	11.0%	$6,282	0.93%	11.9%
2	Atmos Energy Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.80	75%	5.3%	7.5%	11.0%	$5,069	1.19%	12.2%
3	New Jersey Resources	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	10.6%	$2,301	1.75%	12.4%
4	NiSource, Inc.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.80	75%	5.3%	7.5%	11.0%	$11,644	0.80%	11.8%
5	Northwest Natural Gas	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.70	75%	4.6%	6.8%	10.3%	$1,219	1.75%	12.1%
6	Piedmont Natural Gas	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	10.6%	$2,829	1.72%	12.4%
7	South Jersey Industries	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.80	75%	5.3%	7.5%	11.0%	$1,858	1.75%	12.7%
8	Southwest Gas Corp.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.80	75%	5.3%	7.5%	11.0%	$2,405	1.75%	12.7%
9	WGL Holdings, Inc.	2.3%	10.0%	12.3%	3.5%	8.8%	25%	2.2%	0.75	75%	5.0%	7.2%	10.6%	$2,129	1.75%	12.4%
	Average												10.8%			12.3%
	Midpoint (n)												10.6%			12.3%

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 8, 2014).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 10, 2014).
(c) (a) + (b).
(d) Average yield on 30-year Treasury bonds for the six-months ending Jul. 2014 based on data from the Federal Reserve at http://www.federalreserve.gov/releases/h15/data.htm.
(e) (c) - (d).
(f) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).
(g) (e) x weighting factor.
(h) The Value Line Investment Survey (Jun. 6, 2014).
(i) (e) x (h) x weighting factor.
(j) (d) + (g) + (i).
(k) www.valueline.com (retrieved Jun. 16, 2014).
(l) *Morningstar*, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).
(m) (g) + (h).
(n) Average of low and high values.

EMPIRICAL CAPM - PROJECTED BOND YIELD

PROJECTED BOND YIELD

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(f)	(i)		(j)	(k)	(l)	(m)
		Market Return (R_m)				Market										Size
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP				Unadjusted	Market	Size	Adjusted
	Company	Yield	Growth	Equity	Rate	Premium	Weight	RP^1	Beta	Weight	RP^2	Total RP	K_e	Cap	Adjustment	K_e
1	AGL Resources	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.80	75%	4.5%	6.4%	11.2%	$6,282	0.93%	12.1%
2	Atmos Energy Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.80	75%	4.5%	6.4%	11.2%	$5,069	1.19%	12.4%
3	New Jersey Resources	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.9%	$2,301	1.75%	12.6%
4	NiSource, Inc.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.80	75%	4.5%	6.4%	11.2%	$11,644	0.80%	12.0%
5	Northwest Natural Gas	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.70	75%	4.0%	5.9%	10.6%	$1,219	1.75%	12.3%
6	Piedmont Natural Gas	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.9%	$2,829	1.72%	12.6%
7	South Jersey Industries	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.80	75%	4.5%	6.4%	11.2%	$1,858	1.75%	12.9%
8	Southwest Gas Corp.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.80	75%	4.5%	6.4%	11.2%	$2,405	1.75%	12.9%
9	WGL Holdings, Inc.	2.3%	10.0%	12.3%	4.7%	7.6%	25%	1.9%	0.75	75%	4.3%	6.2%	10.9%	$2,129	1.75%	12.6%
	Average												**11.0%**			**12.5%**
	Midpoint (n)												**10.9%**			**12.4%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Jul. 8, 2014).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 from http://finance.yahoo.com (retrieved Jul. 10, 2014).
(c) (a) + (b).
(d) Average projected 30-year Treasury bond yield for 2015-2018 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (May 23, 2014); IHS Global Insight, U.S. Economic Outlook at 79 (May 2014); & Blue Chip Financial Forecasts, Vol. 32, No. 12 (Dec. 1, 2013).
(e) (c) - (d).
(f) Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 190 (2006).
(g) (e) x weighting factor.
(h) The Value Line Investment Survey (Jun. 6, 2014).
(i) (e) x (h) x weighting factor.
(j) (d) + (g) + (i).
(k) www.valueline.com (retrieved Jun. 16, 2014).
(l) *Morningstar*, "2014 Ibbotson SBBI Market Report," at Table 10 (2014).
(m) (g) + (h).
(n) Average of low and high values.

GAS UTILITY RISK PREMIUM

HISTORICAL BOND YIELDS

Current Equity Risk Premium	
(a) Avg. Yield over Study Period	8.57%
(b) Historical Single-A Utility Bond Yield	4.37%
Change in Bond Yield	-4.20%
(c) Risk Premium/Interest Rate Relationship	-0.4589
Adjustment to Average Risk Premium	1.93%
(a) Average Risk Premium over Study Period	3.31%
Adjusted Risk Premium	**5.23%**
Implied Cost of Equity	
(b) Historical Triple-B Utility Bond Yield	4.82%
Adjusted Equity Risk Premium	5.23%
Risk Premium Cost of Equity	**10.05%**

(a) Schedule 8, page 3.
(b) Based on monthly average bond yields from Moody's Investors Service for the six-month period Feb. 2014 - Jul. 2014
(c) Schedule 8, page 4.

GAS UTILITY RISK PREMIUM

PROJECTED BOND YIELDS

	Current Equity Risk Premium	
(a)	Avg. Yield over Study Period	8.57%
(b)	2015-18 Single-A Utility Bond Yield	6.17%
	Change in Bond Yield	-2.39%
(c)	Risk Premium/Interest Rate Relationship	-0.4589
	Adjustment to Average Risk Premium	1.10%
(a)	Average Risk Premium over Study Period	3.31%
	Adjusted Risk Premium	**4.41%**
	Implied Cost of Equity	
(b)	2015-18 Triple-B Utility Bond Yield	6.62%
	Adjusted Equity Risk Premium	4.41%
	Risk Premium Cost of Equity	**11.03%**

(a) Schedule 8, page 3.

(b) Based on data from IHS Global Insight, U.S. Economic Outlook at 79 (May 2014); Energy Information Administration, Annual Energy Outlook 2014 (May 7, 2014); & Moody's Investors Service at www.credittrends.com.

(c) Schedule 8, page 4.

AUTHORIZED RETURNS

Year	Qtr.		(a) Allowed ROE	(b) Single-A Utility Bond Yield	Risk Premium
1980	1		13.45%	13.49%	-0.04%
	2		14.38%	12.87%	1.51%
	3		13.87%	12.88%	0.99%
	4		14.35%	14.11%	0.24%
1981	1		14.69%	14.77%	-0.08%
	2		14.61%	15.82%	-1.21%
	3		14.86%	16.65%	-1.79%
	4		15.70%	16.57%	-0.87%
1982	1		15.55%	16.72%	-1.17%
	2		15.62%	16.26%	-0.64%
	3		15.72%	15.88%	-0.16%
	4		15.62%	14.56%	1.06%
1983	1		15.41%	14.15%	1.26%
	2		14.84%	13.58%	1.26%
	3		15.24%	13.52%	1.72%
	4		15.41%	13.38%	2.03%
1984	1		15.39%	13.56%	1.83%
	2		15.07%	14.72%	0.35%
	3		15.37%	14.47%	0.90%
	4		15.33%	13.38%	1.95%
1985	1		15.03%	13.31%	1.72%
	2		15.44%	12.95%	2.49%
	3		14.64%	12.11%	2.53%
	4		14.44%	11.49%	2.95%
1986	1		14.05%	10.18%	3.87%
	2		13.28%	9.41%	3.87%
	3		13.09%	9.39%	3.70%
	4		13.62%	9.31%	4.31%
1987	1		12.61%	8.96%	3.65%
	2		13.13%	9.77%	3.36%
	3		12.56%	10.61%	1.95%
	4		12.73%	11.05%	1.68%
1988	1		12.94%	10.32%	2.62%
	2		12.48%	10.71%	1.77%
	3		12.79%	10.94%	1.85%
	4		12.98%	9.98%	3.00%
1989	1		12.99%	10.13%	2.86%
	2		13.25%	9.94%	3.31%
	3		12.56%	9.53%	3.03%
	4		12.94%	9.50%	3.44%
1990	1		12.60%	9.72%	2.88%
	2		12.81%	9.91%	2.90%
	3		12.34%	9.93%	2.41%
	4		12.77%	9.89%	2.88%
1991	1		12.69%	9.58%	3.11%
	2		12.53%	9.50%	3.03%
	3		12.43%	9.33%	3.10%
	4		12.38%	9.02%	3.36%
1992	1		12.42%	8.91%	3.51%
	2		11.98%	8.86%	3.12%
	3		11.87%	8.47%	3.40%
	4		11.94%	8.53%	3.41%
1993	1		11.75%	8.07%	3.68%
	2		11.71%	7.81%	3.90%
	3		11.39%	7.28%	4.11%
	4		11.15%	7.22%	3.93%
1994	1		11.12%	7.55%	3.57%
	2		10.81%	8.29%	2.52%
	3		10.95%	8.51%	2.44%
	4	(c)	11.64%	8.87%	2.77%
1995	2		11.00%	7.93%	3.07%
	3		11.07%	7.72%	3.35%
	4		11.56%	7.37%	4.19%
1996	1		11.45%	7.44%	4.01%
	2		10.88%	7.98%	2.90%
	3		11.25%	7.96%	3.29%
	4		11.32%	7.62%	3.70%
1997	1		11.31%	7.76%	3.55%
	2		11.70%	7.88%	3.82%
	3		12.00%	7.49%	4.51%
	4	(c)	11.01%	7.25%	3.76%
1998	2		11.37%	7.12%	4.25%
	3		11.41%	6.99%	4.42%
	4		11.69%	6.97%	4.72%
1999	1		10.82%	7.11%	3.71%
	2	(c)	10.82%	7.48%	3.34%
	4		10.33%	8.05%	2.28%
2000	1		10.71%	8.29%	2.42%
	2		11.08%	8.45%	2.63%
	3		11.33%	8.25%	3.08%
	4		12.50%	8.03%	4.47%
2001	1		11.16%	7.74%	3.42%
	2	(c)	10.75%	7.93%	2.82%
	4		10.65%	7.68%	2.97%
2002	1		10.67%	7.65%	3.02%
	2		11.64%	7.50%	4.14%
	3		11.50%	7.19%	4.31%
	4		10.78%	7.15%	3.63%
2003	1		11.38%	6.93%	4.45%
	2		11.36%	6.40%	4.96%
	3		10.61%	6.64%	3.97%
	4		10.84%	6.35%	4.49%
2004	1		11.10%	6.09%	5.01%
	2		10.25%	6.48%	3.77%
	3		10.37%	6.13%	4.24%
	4		10.66%	5.94%	4.72%
2005	1		10.65%	5.74%	4.91%
	2		10.52%	5.52%	5.00%
	3		10.47%	5.51%	4.96%
	4		10.40%	5.82%	4.58%
2006	1		10.63%	5.85%	4.78%
	2		10.50%	6.37%	4.13%
	3		10.45%	6.19%	4.26%
	4		10.14%	5.86%	4.28%
2007	1		10.44%	5.90%	4.54%
	2		10.12%	6.09%	4.03%
	3		10.03%	6.22%	3.81%
	4		10.27%	6.08%	4.19%
2008	1		10.38%	6.15%	4.23%
	2		10.17%	6.32%	3.85%
	3		10.49%	6.42%	4.07%
	4		10.34%	7.23%	3.11%
2009	1		10.24%	6.37%	3.87%
	2		10.11%	6.39%	3.72%
	3		9.88%	5.74%	4.14%
	4		10.27%	5.66%	4.61%
2010	1		10.24%	5.83%	4.41%
	2		9.99%	5.61%	4.38%
	3		9.93%	5.09%	4.84%
	4		10.09%	5.34%	4.75%
2011	1		10.10%	5.60%	4.50%
	2		9.85%	5.38%	4.47%
	3		9.65%	4.81%	4.84%
	4		9.88%	4.37%	5.51%
2012	1		9.63%	4.39%	5.24%
	2		9.83%	4.23%	5.60%
	3		9.75%	3.98%	5.77%
	4		10.07%	3.93%	6.14%
2013	1		9.57%	4.18%	5.39%
	2		9.47%	4.23%	5.24%
	3		9.60%	4.74%	4.86%
	4		9.83%	4.76%	5.07%
2014	1		9.54%	4.56%	4.98%
	2		9.84%	4.32%	5.52%
Average			11.89%	8.57%	3.31%

(a) Regulatory Research Associates, Inc., Major Rate Case Decisions, (Jul. 10, 2014, Jan. 24, 2002, Jan. 18, 1995, and Jan. 16, 1990).

(b) Moody's Investors Service.

(c) No decisions reported for following quarter.

GAS UTILITY RISK PREMIUM

REGRESSION RESULTS

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9398234
R Square	0.8832681
Adjusted R Square	0.8823838
Standard Error	0.0053022
Observations	134

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.028079089	0.028079	998.7963	2.00386E-63
Residual	132	0.003710907	2.81E-05		
Total	133	0.031789996			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0723827	0.001325659	54.6013	1.8E-92	0.069760403	0.07500496	0.069760403	0.075004964
X Variable 1	-0.4589493	0.014521995	-31.6037	2E-63	-0.487675253	-0.43022344	-0.48767525	-0.43022344

EXPECTED EARNINGS APPROACH

GAS GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	AGL Resources	6.0%	1.022546	6.1%
2	Atmos Energy Corp.	8.5%	1.046952	8.9%
3	New Jersey Resources	12.5%	1.026608	12.8%
4	NiSource, Inc.	10.0%	1.006814	10.1%
5	Northwest Natural Gas	10.5%	1.025003	10.8%
6	Piedmont Natural Gas	11.0%	1.021693	11.2%
7	South Jersey Industries	15.5%	1.040978	16.1%
8	Southwest Gas Corp.	10.5%	1.026532	10.8%
9	WGL Holdings, Inc.	10.0%	1.019378	10.2%
	Average (d)			**11.4%**
	Midpoint (e)			**12.5%**

(a) The Value Line Investment Survey (Jun. 6, 2014).
(b) Adjustment to convert year-end return to an average rate of return from Schedule 5.
(c) (a) x (b).
(d) Excludes highlighted figures.
(e) Average of low and high values.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF DANIEL L. RAUSCH

ON BEHALF OF NORTHWESTERN ENERGY

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1 **Exhibits**

2 **Natural Gas Consolidated Utility**

3 Capital Structure and Rate of Return	Exhibit__(DLR-1)
4 Cost of Long-Term Debt	Exhibit__(DLR-2)
5 Adjusted Rate Base for Capitalization	Exhibit__(DLR-3)

6 **Natural Gas Production Assets - True-Up**

7 Capital Structure and Rate of Return	Exhibit__(DLR-4)
8 Cost of Long-Term Debt	Exhibit__(DLR-5)
9 Adjusted Rate Base for Capitalization	Exhibit__(DLR-6)

10

11 **Witness Information**

12 **Q. Please state your name and business address.**

13 **A.** My name is Daniel L. Rausch. My business address is 3010 W. 69th

14 Street, Sioux Falls, South Dakota 57108.

15

16 **Q. By whom are you employed and in what capacity?**

17 **A.** I am employed by NorthWestern Energy ("NorthWestern" or "Company")

18 as the Treasurer.

19

20 **Q. How long have you been employed in your current position?**

21 **A.** I have been the Treasurer since December 2012.

22

23 **Q. What are your responsibilities and duties in your current position?**

1 **A.** I am responsible for the areas of Treasury, Corporate Strategic Planning,
2 and Business Development.
3
4 **Q. Please summarize your work experience and educational**
5 **background.**
6 **A.** I have 28 years of experience within the fields of corporate finance,
7 treasury, tax, audit, and accounting. Prior to being named Treasurer at
8 NorthWestern, I was responsible for the direction of Investor Relations and
9 Corporate Strategic Planning for seven years. Over that time, I
10 maintained communications with investors, met with ratings agencies on
11 behalf of NorthWestern, and worked with senior management to identify
12 and develop business strategy for NorthWestern. I have a Bachelor of
13 Science degree in Accounting from the University of South Dakota. I also
14 have my Certified Public Accountant certificate in inactive status.
15
16 **Purpose of Testimony**
17 **Q. What is the purpose of your testimony?**
18 **A.** My testimony will discuss the Montana Natural Gas Transportation,
19 Distribution, Storage, and Production Utility's ("Natural Gas Consolidated
20 Utility") capitalization, cost of debt, cost of equity, and the rate of return
21 proposed for this proceeding. I will also discuss the capitalization, cost of
22 debt, cost of equity, and rate of return used to calculate the revenue
23 requirement for the two natural gas production assets: the Nabors First

1 Reserves Natural Gas Properties ("Bear Paw (NFR)") and the Devon
2 Natural Gas Properties ("South Bear Paw (Devon)"), from 2013 to 2015 in
3 support of NorthWestern's Natural Gas Production Assets - True-Up
4 ("Natural Gas Production Assets - True-Up") discussed in the Prefiled
5 Direct Testimony of Patrick J. DiFronzo ("DiFronzo Direct Testimony").
6
7 **Q. How is your testimony organized?**
8 **A.** My testimony is divided into two sections. First, I describe how
9 NorthWestern arrived at the overall rate of return proposed for the Natural
10 Gas Consolidated Utility. Specifically, I (1) explain how NorthWestern
11 derived the capital structure, (2) discuss the cost of debt, (3) discuss the
12 cost of equity, and (4) combine the cost of debt and the cost of equity with
13 their relative weightings in the capital structure to arrive at the overall rate
14 of return. In the second section, I describe how NorthWestern computed
15 the rate of return proposed for use in the Natural Gas Production Assets -
16 True-Up including an explanation of the capital structure, cost of debt and
17 cost of equity used in that computation.
18
19 **Q. What are your conclusions?**
20 **A.** Below is a summary of my conclusions.
21 For the Natural Gas Consolidated Utility:
22 • the capital structure recommended is 53.21% debt and 46.79% equity;
23 • the cost of debt is 4.67%;

- the cost of equity recommended is 10.35%; and
- the rate of return recommended is 7.33%.

This summary is shown on Exhibit__(DLR-1), attached hereto.

For the Natural Gas Production Assets - True-Up:

- the capital structure recommended is 53.87% debt and 46.13% equity;
- the cost of debt is 5.60%;
- the cost of equity recommended for Bear Paw (NFR) is 10.00% and for South Bear Paw (Devon) is 9.80%; and
- the rate of return recommended for Bear Paw (NFR) is 7.63% and for South Bear Paw (Devon) is 7.54%.

This summary is shown on Exhibit__(DLR-4), attached hereto.

SECTION I: MONTANA NATURAL GAS CONSOLIDATED UTILITY

Capitalization

Q. Please explain the capitalization methodology that you have presented in this case.

A. In determining the regulated capital structure, I used the regulated Montana assets and liabilities (or rate base) of the Montana utility as its total capitalization. I derived the equity of the regulated utility by deducting the debt associated with the regulated utility from the regulated utility's rate base amount. In this filing, using the total Montana utility 13-month

average rate base amount for test year 2015 and the total Montana jurisdictional long-term debt as of December 31, 2015 (adjusted to reflect a recent debt issuance discussed below), I calculated a capital structure comprised of 53.21% debt and 46.79% equity.

Q. Is NorthWestern's methodology of using rate base to derive capitalization in this filing consistent with past Montana Public Service Commission ("Commission") orders?

A. Yes. In Docket No. D2007.7.82, the Commission determined that the use of rate base to derive capitalization is the preferred method for calculating the Company's capital structure for rate-making purposes. Paragraphs 72 and 73 of Order No. 6852f stated that:

> *For regulatory purposes, the PSC evaluated NWE's regulated Montana capital structure using Montana regulated assets and liabilities to derive the Montana regulated equity. This information was provided in NWE Exhibit 11. The Montana NWE regulated electric and gas rate base is $931 million; long-term debt totals $481 million; and, as a result, equity is $450 million. This derives a Montana regulated capital structure of 52 percent debt and 48 percent equity, which is a capital structure close to NWE's consolidated capital structure and one that does* ***not*** *include goodwill. (emphasis in original)*

In Docket No. D2009.9.129, consistent with Order No. 6852f in Docket No. D2007.7.82, NorthWestern used the rate base of the Montana utility and the debt associated with the Montana utility to derive the capital structure for rate-making purposes. The calculated capital structure in that rate

case was 50.55% debt and 49.45% equity. The final capital structure stipulated between the Montana Consumer Counsel ("MCC") and the Company, and subsequently approved by the Commission, was 52% debt and 48% equity. There is no indication in Order No. 7046i that the Commission disapproves of the use of rate base in determining the capitalization for NorthWestern.

In Docket No. D2012.9.94, NorthWestern once again used the rate base of the Montana utility and the debt associated with the Montana utility to derive the capital structure for rate-making purposes. The calculated capital structure in that rate case was 52.33% debt and 47.67% equity. In its rebuttal testimony filing, the Battle Creek natural gas production assets were added to the filing and the capital structure was updated to 52.35% debt and 47.65% equity. In Order No. 7249e, the Commission approved a stipulated revenue requirement increase and a 9.8% return on equity. In its annual reports to the Commission subsequent to Order No. 7249e, NorthWestern has reported its regulatory capital structure and costs using the capital structure of 52.35% debt and 47.65% equity on Schedule 22. The Commission has never questioned this report.

Q. Please explain the rate base amount used in calculating the capital structure presented in this case.

1 **A.** The rate base amount used in this filing is $2.7 billion, which represents
2 the 13-month average rate base amount for the Montana total electric
3 utility for test year 2015 from Schedule 27 of the 2015 Annual Report filed
4 with the Commission and the adjusted 13-month average rate base
5 amount for the Montana total natural gas utility presented in this filing and
6 as described in the Prefiled Direct Testimony of Crystal D. Lail. This total
7 rate base amount also excludes the $31.6 million rate base reduction
8 agreed to in the Stipulation Agreement in Docket No. D2007.7.82. This
9 calculation is shown on Exhibit__(DLR-3).
10
11 **Q. Please explain why NorthWestern is using the total Montana electric**
12 **and natural gas utility rate base amount rather than just the natural**
13 **gas utility rate base amount given that this is a natural gas rate case**
14 **filing.**
15 **A.** Over the years, NorthWestern has evolved into a vertically integrated
16 utility and continues to raise capital as a consolidated utility. The Montana
17 utility is now comprised of electric transmission, distribution, and
18 generation, as well as natural gas transportation, distribution, storage and
19 production ("Montana Total Utility"). All equity is issued through
20 NorthWestern Corporation. Debt is issued either through the Montana
21 mortgage indenture, for the Montana utility capital needs, or through the
22 South Dakota mortgage indenture, for the South Dakota utility capital
23 needs. NorthWestern does not consider a different capital raising process

for natural gas versus electric assets. Since this is a Montana jurisdictional filing, it makes sense to use the capital structure of the Montana Total Utility.

Q. Will NorthWestern apply this same methodology of using its total jurisdictional capital structure in future rate cases?

A. Yes.

Q. Please explain why you excluded the $31.6 million of rate base reduction ordered in the Stipulation Agreement in Docket No. D2007.7.82 when calculating the capitalization of the Montana Total Utility.

A. The $31.6 million (originally $38.8 million) rate base reduction was part of the negotiated settlement between the MCC and NorthWestern in Docket No. D2007.7.82, and, among other things, it effectively reduced the amount of NorthWestern's revenue requirement in future rate cases in exchange for the $15 million rate increase granted to NorthWestem in that docket. By artificially reducing NorthWestern's rate base amount, the revenue requirement calculated based on a lower rate base amount will be lower. To further explain the nature of this Property, Plant and Equipment ("PP&E") adjustment, ¶ 86 of Order No. 6852f states that:

> *The Stipulation specifies the regulatory accounting treatment for capital expenditures for improvements and updates to existing electric transmission and distribution and natural gas transmission, distribution and storage facilities. For each of*

the years 2008 and 2009, $19.4 million will be deducted from gross plant, and the depreciation reserve associated with that plant will be deducted from the total depreciation reserve for ratemaking purposes. This $38.8 million reduction in rate base has a net present value to ratepayers of approximately $31 million based on a discount rate of 8 percent. The associated depreciation expense will be included in cost of service. These investments will be allocated two-thirds to electric delivery service and one-third to natural gas delivery service.

If this PP&E-stipulated adjustment were to apply in determining the capitalization of the utility, the utility's capitalization would be artificially reduced, resulting in a higher debt to rate base ratio. The higher debt to rate base ratio would result in a lower rate of return and thus, generate further benefits to ratepayers (at the expense of shareholders), an unintended consequence of double dipping on the benefits that were intended by the Stipulation.

Most importantly, capitalization is often defined as the total debt and total equity used by a business to finance its assets; hence, the use of rate base assets as a proxy for determining a utility's capitalization is reasonable. The capitalization used in this filing should represent the total capital employed by NorthWestern to invest in its Montana jurisdictional utility long-term assets; in this case, this is the Montana Total Utility rate base amount without the negotiated PP&E reduction prescribed by the Stipulation. In other words, the $31.6 million of PP&E are real assets, which were capitalized using debt and equity and are therefore part of the

total capitalization of the Montana Total Utility. To exclude these assets from the use of rate base as capitalization would result in understating the capitalization of the Montana Total Utility. Furthermore, in order to maintain the integrity of the capital structure calculation, if the $31.6 million of PP&E is not included in rate base, then the debt allocated to these assets should not be included in the total debt amount either (i.e., if the denominator does not include the $31.6 million of assets, neither should the numerator include the debt related to these assets).

Q. Is the exclusion of this stipulated reduction to PP&E in calculating rate base as a proxy for capitalization consistent with past Commission orders?

A. Yes. In Docket No. D2007.7.82, Order No. 6852f, the Commission determined that the rate base amount to be used as a proxy for capitalization was $931 million and this amount excludes the $38.8 million reduction to PP&E. Neither in Docket No. 2009.9.129, Order No. 7046i, nor in Docket D2012.9.94, Order No. 7249e, was there an indication that the Commission did not approve of this exclusion.

Q. Please explain the debt amount used in calculating the capital structure presented in this case.

A. Consistent with the using the Montana Total Utility rate base amount, I used only the Montana jurisdictional long-term debt to come up with the

1 total debt for this filing. None of the Montana jurisdictional debt is
2 specifically secured by either the electric utility assets or the natural gas
3 utility assets. The Montana Total Utility debt used in this filing is $1.4
4 billion, which is the Montana Total Utility long-term debt as of December
5 31, 2015, but adjusted to reflect the refinancing of the $170,205,000
6 4.65% City of Forsyth pollution control bonds with a $144,660,000 2.0%
7 City of Forsyth pollution control bonds in August of 2016 as explained
8 below. This calculation is shown on Exhibit__(DLR-2).
9
10 **Q. Please explain why you included only $1.0 million of the $27.0 million**
11 **of New Market Tax Credit ("NMTC") debt in the debt amount used in**
12 **calculating the capital structure.**
13 **A.** The $27.0 million of NMTC debt is the debt issued to finance the
14 construction of NorthWestern's general office building in Butte, Montana.
15 The NMTC Program was established to spur community development and
16 economic growth in low-income communities by incentivizing private
17 investments in these areas using tax credits. NorthWestern took
18 advantage of this program to reduce the cost of constructing its office
19 building, allowing this cost savings to be passed on to ratepayers in the
20 form of a lower rate base amount for the building. Although the $27.0
21 million appears as debt on the Company's balance sheet, the net
22 obligation of the Company to this loan is expected to be $1.0 million. As
23 part of the structure of this financing, NorthWestern lent $18.2 million to a

1 special purpose entity, who in turn used these funds, together with $8.8
2 million of funds from a private investor and $1.0 million from the Montana
3 Community Development Corporation, to lend $27.0 million to
4 NorthWestern to pay for the building project and $1.0 million of transaction
5 fees and expenses. At the end of the 7-year term of the financing, $7.8
6 million of the $27.0 million loan is expected to be forgiven, $18.2 million of
7 the remaining $19.2 million is expected to be returned to NorthWestern,
8 and $1.0 million is expected to be paid back to the Montana Community
9 Development Corporation. As such, only $1.0 million of the $27.0 million
10 is deemed to be a true debt obligation of NorthWestern.
11
12 **Q. Please explain why you did not include short-term debt in the**
13 **calculation of capital structure for this proceeding.**
14 **A.** There are two reasons the short-term revolving credit facility was not
15 included in the debt portion of the capital structure.
16
17 First, short-term debt is used for working capital purposes. Appropriately,
18 ARM 38.5.147 requires that the debt capital to be included in the
19 calculation of rate of return be based on the "long-term debt outstanding
20 according to the most recently available balance sheet." This rule is
21 reasonable given that long-term debt is used to finance utility rate-based
22 assets while short-term debt is used to fund temporary financing needs,
23 which, in our case, are cash needs related to energy supply purchases,

1 property taxes, construction work in progress, dividends, and other
2 working capital items for all of NorthWestern's jurisdictions. Accordingly,
3 we have never included short-term debt in the calculation of capital
4 structure in previous rate cases.
5
6 Second, if NorthWestern's corporate structure was set up as a holding
7 company structure, like most of the utility companies in our industry, none
8 of the unsecured short-term debt would be at the local utility level. The
9 unsecured revolving credit facilities are typically set at the holding
10 company level, and the rating agencies use the consolidated interest
11 levels to calculate corporate ratios. In those cases, the state level utility
12 company debt levels are kept lower to protect the local customers from
13 any non-local utility debt obligations. NorthWestern's lack of a holding
14 company structure is somewhat unique in the utility industry. In order to
15 accommodate our flat divisional structure and protect Montana customers,
16 the short-term revolving credit facility is not secured by any Montana rate-
17 based assets.
18
19 For these reasons, the short-term unsecured borrowings <u>should not</u> be
20 deemed part of NorthWestern's permanent Montana capital structure.
21
22 **Q. Please explain how the equity amount used in this filing is**
23 **calculated.**

1 **A.** The equity is derived by deducting the Montana Total Utility long-term debt
2 from the Montana Total Utility rate base ($2.7 billion total rate base less
3 $1.4 billion of long-term debt, determined as described above, equals $1.3
4 billion of derived equity). The resulting capital structure is 53.21% debt
5 and 46.79% equity.
6
7 **Q. Is the calculated 53.21% debt / 46.79% equity capital structure**
8 **appropriate to use for this rate case?**
9 **A.** Yes, I believe that this calculated capital structure most accurately reflects
10 the true capitalization of the Montana Total Utility business and is also the
11 capital structure that will allow us to maintain our investment grade
12 corporate credit ratings.
13
14 **Q. Are your credit ratings still important in this low interest rate**
15 **environment?**
16 **A.** Yes. Strong credit ratings allow us to maintain access to the capital
17 markets at all times and at a reasonable cost. A lack of financial strength
18 can limit a company's ability to finance assets, or undertake new projects,
19 particularly during times of capital market volatility. The recent market
20 volatility stemming from the uncertain economic outlook highlights why
21 financial strength is important as it ensures that the Company will have the
22 flexibility to withstand these unanticipated macro-economic events that are
23 outside of our control.

1 **Q. Have your credit ratings always been strong?**

2 **A.** No. In the later part of the 1990s the Company leveraged growth with
3 debt. Our credit ratings steadily declined and the Company experienced
4 extreme financial hardship. Our credit ratings bottomed out in 2003 with a
5 rating of 'D' by Standard & Poor's Ratings ("S&P). It took until 2007 to
6 achieve a 'BBB' rating with S&P, which is considered an investment grade
7 credit rating.

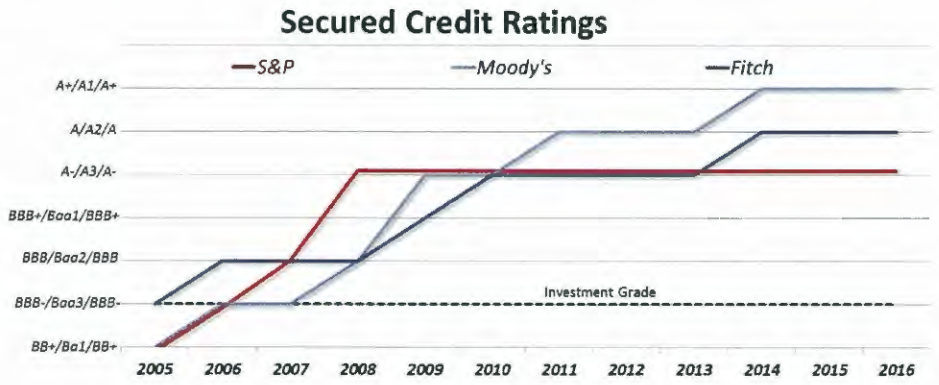
8

9 **Q. What are your credit ratings now?**

10 **A.** Over the prior decade, we have succeeded in improving our credit ratings
11 steadily. Our current ratings are:

	Senior Secured Rating	Senior Unsecured Rating	Commercial Paper	Outlook
Fitch	A	A-	F2	Stable
Moody's	A1	A3	Prime-2	Negative
S&P	A-	BBB	A-2	Stable

12 See following table for a recent history of our credit ratings:



13 **Q. What is the relevance of the improved credit ratings to NorthWestern**
14 **customers?**

1 **A.** Our improved financial strength has benefitted our retail customers in
2 three different ways. First, our improved credit ratings result in lower
3 borrowing costs, which are directly passed on to customers. Our 2016
4 issuance, which I described previously, is the lowest coupon bond in our
5 portfolio ($144.7 million of 7-year tax exempt notes at 2.0 percent).
6
7 Second, the Company's credit strength has provided us with the flexibility
8 to proactively take advantage of favorable market conditions for the
9 benefit of our customers. Because of our financial strength, we have
10 significant flexibility in the timing of financings, which was demonstrated
11 through the Hydro acquisition in November of 2014. We were able to go
12 to market for financing that was large relative to the size of the Company,
13 yet the investors' order book was about 2 times the offering size of $450
14 million, allowing the cost of this debt to be set at a reasonable level. In
15 short, the Company's financial health has directly benefitted its customers
16 through lower interest rates and provides the Company with financial
17 flexibility to take advantage of opportunities that allow us to reduce our
18 costs for the benefit of our customers.
19
20 Finally, as a result of our financial strength, we have been able to take a
21 proactive approach to investing in our utility infrastructure. Over the last
22 five years, the Company has successfully invested over $750 million in its
23 electric and natural gas utilities in Montana, in addition to the successful

acquisition of the Hydro assets from PPL Montana. Related specifically to the Natural Gas Consolidated Utility, our investments were about $216 million over the last five years.

Q. Are NorthWestern's current credit ratings with all three rating agencies stable?

A. NorthWestern's credit outlook with S&P and Fitch are rated "stable" now. However, in a January 25, 2016 report on the Company, Moody's Investors Service ("Moody's") reduced our credit outlook to 'negative' citing that the Montana regulatory environment is not as favorable as some of our peers in the Northwest. Specifically, Moody's stated:

> *NWE operates without some of the cost recovery features that we see in more supportive regulatory environments. For example, we note that many of NWE's northwest peers have rate design that enhances their utility credit profile, including forward looking test years in rate cases, revenue decoupling mechanisms, and/or higher equity layers from which to generate returns.*

Moody's gave a couple examples of future activities that could result in a downgrade of our current rating of A3. The Moody's report stated:

> *... if NorthWestern fails to receive adequate and timely cost recovery from either the Montana Public Service Commission ("MPSC") or other regulatory authorities, or implements more aggressive dividend or debt financing policies, then a downgrade would result.*

In addition, in a report issued by Moody's on the Company on April 1, 2016, Moody's commented:

> *On 29 March, the Montana Public Service Commission (MPSC) voted to disallow cost recovery to NorthWestern Corp (NWE, A3 negative) for around $8 million of replacement power costs it has collected related to a 2013 outage at its Colstrip Unit 4 coal fired generating plant. The decision is credit negative for NWE because it is another sign of a challenging regulatory relationship in Montana, NWE's primary service territory.*

Because Montana comprises the largest part of NorthWestern's service area, ratings agencies are especially focused on regulatory outcomes in Montana.

Cost of Debt

Q. How did you determine the total long-term debt?

A. For the long-term debt existing as of December 31, 2015, I identified all Montana jurisdictional debt. Please see Exhibit__(DLR-2) for the details.

Q. How did you determine the cost of debt?

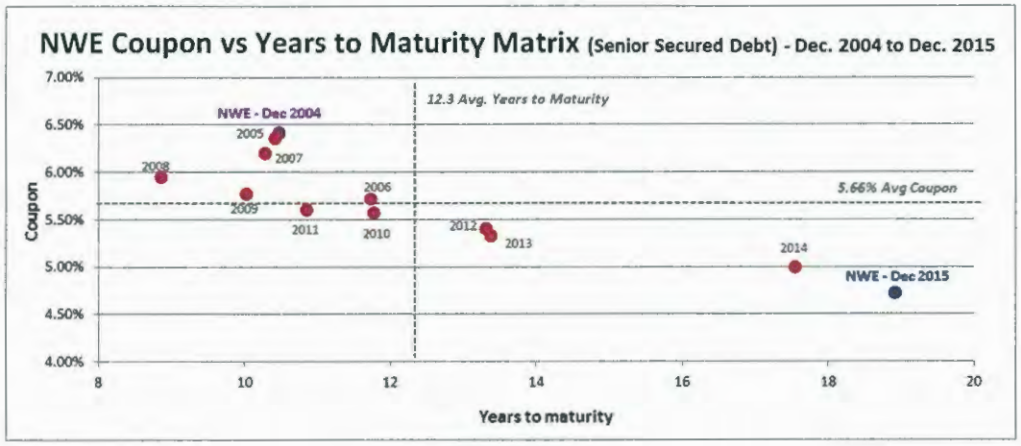
A. To derive the annual cost of long-term debt, I added the annual interest cost and the annual amortization of debt discount and issuance expense associated with each debt component. By dividing the total annual cost of long-term debt by the long-term debt balance, I determined a cost of long-term debt of 4.67% (see Exhibit__(DLR-2)).

Q. How does this cost of debt compare to the cost of debt filed in the previous rate cases?

1 **A.** The cost of debt of 4.67% is significantly lower than the cost of debt filed
2 in previous general rate cases (5.37% in Docket No. D2012.9.94, 5.76% in
3 Docket No. D2009.9.129, and 5.76% in Docket No. D2007.7.82).
4
5 **Q. How was the Company able to achieve this type of interest cost**
6 **savings for the ratepayers?**
7 **A.** As stated earlier, our financial strength, combined with the current low
8 interest rate environment and proactive debt refinancing, resulted in lower
9 borrowing costs, which are directly passed on to customers. Since the
10 last rate case, NorthWestern completed the following Montana debt
11 financing:
12 • In August 2012, $60 million at an interest rate of 4.15% for 30 years
13 and $40 million at an interest rate of 4.30% for 40 years;
14 • In December 2013, $35 million at a rate of 3.99% for 15 years and $15
15 million at a rate of 4.85% for 30 years;
16 • In May 2015, $75 million at an interest rate of 3.11% for 10 years and
17 $125 million at 4.11% for 30 years primarily to refinance the then-
18 existing 6.04% $150 million debt due in 2016; and
19 • In August 2016, $144.7 million of 7-year tax-exempt notes at 2.00% for
20 7 years to refinance the then-existing 4.65% $170.2 million tax-exempt
21 debt due in 2023.
22

Q. How did these financing activities improve NorthWestern's debt profile?

A. Not only did the financing activities lower the cost of debt, they also lengthened the company's debt maturity profile, allowing the company to lock in these lower rates for a longer period of time.



Cost of Equity

Q. How did you determine the cost of equity?

A. I relied on the analysis performed by Mr. Adrien McKenzie of FINCAP LLC, which is explained in his prefiled direct testimony. Mr. McKenzie's analysis shows a range of reasonableness of ROE for a natural gas utility of 9.5% to 10.7%, with an estimated mid-point of 10.1%, plus a 0.25% risk adjustment, for a recommended ROE for NorthWestern of 10.35%. I agree with Mr. McKenzie's assessment and have used the recommended 10.35% in calculating NorthWestern's rate of return.

1 **Rate of Return**

2 **Q. How did you determine the overall rate of return required for the**
3 **Natural Gas Consolidated Utility in Montana?**

4 **A.** The overall rate of return required for the Natural Gas Consolidated Utility
5 in Montana is simply the cost of debt and cost of equity appropriate for the
6 utility weighted by the percentage of debt and rate base-derived equity.
7 The resulting rate of return for the Natural Gas Consolidated Utility is
8 7.33%. This calculation is shown in Exhibit__(DLR-1). The proposed
9 ROR of 7.33% is a reduction from the currently reported Schedule 22
10 ROR of 7.48% for the Natural Gas Consolidated Utility (based on a capital
11 structure of 52.35% debt/47.65% equity and an authorized ROE of 9.80%
12 from Docket No. D2012.9.94 Order No. 7249e).

13

14 **SECTION II: NATURAL GAS PRODUCTION ASSETS - TRUE-UP**

15

16 **Q. What is the purpose of preparing a cost of capital computation for**
17 **the Natural Gas Production Assets – True-Up filing?**

18 **A.** As explained in the Prefiled Direct Testimony of Patrick R. Corcoran,
19 NorthWestern is required to present several differing approaches to
20 ratemaking for the gas production assets in this filing. These approaches
21 require historical analyses using both test period and actual annual
22 revenue requirement computations, as well as forecast annual revenue
23 requirements for each of the gas production properties. Revenue

requirement computations are required for Bear Paw (NFR) from November 2012 through 2019, and South Bear Paw (Devon) from December 2013 through 2019. Because a final order was issued for Battle Creek based on a 2011 test year, the approved cost of capital from that order was used for Battle Creek from 2011 through 2015. In order to perform these analyses for Bear Paw (NFR) and South Bear Paw (Devon), costs of capital are needed for the years 2012 through 2015. For 2016 through 2019, the cost of capital calculated for the Natural Gas Consolidated Utility in Section I above is used to forecast the revenue requirement for all the gas production assets.

Q. Why is NorthWestern proposing a cost of capital computation based on information as of mid-2014?

A. Rather than perform detailed cost of capital computations for each of the historic test years from 2012 to 2015, NorthWestern determined that a historic cost of capital based on information as of mid-2014 was a reasonable proxy for these historic time periods given that NorthWestern would have likely filed one rate case to seek to include both Bear Paw (NFR) and South Bear Paw (Devon) in rate base around mid-2014, since the last gas production asset (South Bear Paw (Devon)) was acquired in November 2013. Therefore, a cost of capital analysis based on mid-2014 information – a cost of debt and capital structure based on a 2013 test year, and a return on equity based on market data as of mid-2014 – is

reasonable. This mid-2014 historic cost of capital computation is being used to determine the final true-up of bridge rates to actual revenue requirement computations for Bear Paw (NFR) for November 2012 through 2015, and for South Bear Paw (Devon) for December 2013 through 2015.

Capitalization

Q. Please explain the capitalization methodology used for the Natural Gas Production Assets – True-Up.

A. Consistent with the methodology used for the Natural Gas Consolidated Utility rate filing discussed in Section I, I used the total rate base of the Montana Total Utility using a 2013 test period to derive the capitalization. Using this methodology, I calculated a capital structure comprised of 53.87% debt and 46.13% equity. Please refer to Exhibit__(DLR-4) for the details of the calculation.

Q. Please explain the rate base amount used in calculating the capital structure for the Natural Gas Production Assets - True-Up.

A. For this filing, we are assuming that a rate case for the gas production assets was filed in mid-2014 and, therefore, are using the 13-month average rate base amount for the Montana Total Utility for test year 2013, adjusted to reflect the full amount of rate base for the South Bear Paw (Devon) gas production assets which were acquired in November 2013.

For the South Bear Paw (Devon) gas production assets, instead of using the 13-month average rate base of $4.7 million for 2013, the 2013 year-end rate base of $60.6 million is used. Since the debt raised to purchase the South Bear Paw (Devon) gas production asset was already part of the Montana Total Utility long-term debt as of December 31, 2013, the rate base amount should be adjusted to reflect the size of Devon at December 31, 2013. The total rate base amount is calculated to be $1.7 billion.

Q. Please explain the debt amount used in calculating the capital structure for the True-Up.

A. Consistent with the methodology used for the Natural Gas Consolidated Utility discussed in Section I, for the long-term debt existing as of December 31, 2013, I identified all the debt issued under the Montana mortgage indenture which totaled $936.1 million. This calculation is shown on Exhibit__(DLR-5).

Q. Please explain how the equity amount used for the True-Up is calculated.

A. The equity is derived by deducting the Montana Total Utility long-term debt from the adjusted Montana Total Utility rate base ($1.7 billion total rate base less $936.1 million of long-term debt, determined as described above, equals $800.0 million of derived equity) using the 2013 test period.

1 **Cost of Debt**

2 **Q. How did you determine the cost of debt?**

3 **A.** To derive the annual cost of long-term debt, I added the annual interest
4 cost and the annual amortization of debt discount and issuance expense
5 associated with each debt component of the Montana jurisdictional debt.
6 By dividing the total annual cost of long-term debt by the long-term debt
7 balance, I determined a cost of long-term debt of 5.60% (see
8 Exhibit__(DLR-5)).
9

10 **Cost of Equity**

11 **Q. How did you determine the cost of equity?**

12 **A.** As explained in his prefiled direct testimony, Mr. Adrien McKenzie of
13 FINCAP LLC, performed some analyses on an appropriate rate of return
14 on equity for NorthWestern's natural gas utility, assuming a rate filing in
15 the third quarter of 2014 and using market data in the mid-2014 time
16 frame. Mr. McKenzie's analysis shows a range of reasonableness of ROE
17 for a natural gas utility of 9.8% to 11.0%, with a midpoint estimate of
18 10.4%. Adding a 0.25% risk adjustment for the lack of recovery
19 mechanism and impact of attrition, Mr. McKenzie recommended an ROE
20 for NorthWestern of 10.65%.
21

22 For the purpose of determining the true-up between the bridge rates used
23 for Bear Paw (NFR) from September 2012 through 2015 and the annual

revenue requirements proposed in this filing, NorthWestern proposes using a ROE equal to the most recent ROE authorized by the Commission at the time of the acquisition of Bear Paw (NFR) of 10.00% (Docket No. D2011.5.41, Order No. 7159l for the Spion Kop Wind Generation Project). This is the same rate used by NorthWestern in its evaluation models for the asset purchase[1] and is within Mr. McKenzie's range of reasonableness of ROE for that time period. The 10.00% is the ROE that resulted from a settlement of several issues in the Spion Kop rate filing.

For the purpose of determining the true-up between the bridge rates used for South Bear Paw (Devon) from December 2013 through 2015 and the annual revenue requirements proposed in this filing, NorthWestern proposes using a ROE equal to the most recent ROE authorized by the Commission (Docket No. D2012.9.94, Order No. 7249e for the Natural Gas Transportation, Distribution and Storage and Battle Creek Production assets) at the time of the acquisition of South Bear Paw (Devon) of 9.80%. Once again, this is the same rate used by NorthWestern in its evaluation models for the purchase of South Bear Paw (Devon)[2] and is at the lowest end of Mr. McKenzie's range of reasonableness of ROE for that time period. The 9.80% is the ROE that resulted from a settlement of several issues in the Montana Natural Gas Transportation, Distribution and

[1] See Prefiled Direct Testimony of Travis E. Meyer Exhibit__(TEM-1).
[2] See Prefiled Direct Testimony of Travis E. Meyer Exhibit__(TEM-2).

Storage assets rate filing. Order No. 7249e also required that 9.80% ROE be used for the Battle Creek Production asset.

Rate of Return

Q. How did you determine the overall rate of return required for the Natural Gas Production Assets - True-Up?

A. The overall rate of return required for the Natural Gas Production Assets – True-Up is simply the cost of debt and cost of equity appropriate for the production asset weighted by the percentage of debt and rate base-derived equity. In the case of Bear Paw (NFR), the resulting rate of return is 7.63%. For South Bear Paw (Devon), the resulting rate of return is 7.54%. This calculation is shown in Exhibit__(DLR-4).

Q. Does this complete your testimony?

A. Yes, it does.

NORTHWESTERN ENERGY

Capital Structure and Rate of Return

MONTANA NATURAL GAS CONSOLIDATED (T&D AND PRODUCTION) UTILITY GENERAL FILING

Test Year ending December 31, 2015

(Thousands of Dollars)

	Amount	Percent of Capitalization	Rate	Rate of Return
Total Montana Utility Long-Term Debt	$1,411,606	53.21%	4.67%	2.49%
Derived Regulated Equity *	1,241,162	46.79%	10.35% **	4.84%
Total Montana Utiilty Rate Base	$2,652,768	100.00%		7.33%

* Regulated Equity is equal to Total Montana Utility Rate Base as Capitalization (Exhibit__DLR-3, Line 10) less Total Montana Utility Long-Term Debt

** The rates of return on equity are based on analysis provided by Mr. Adrien McKenzie.

NORTHWESTERN ENERGY
MONTANA NATURAL GAS CONSOLIDATED UTILITY FILING
MONTANA TOTAL UTILITY LONG-TERM DEBT
Pro Forma for the August 2016 Issuance of $144.7MM 2.0% MT Pollution Control Bonds
December 31, 2015

Line No.	Jurisdiction	Type	(a) Issue Title	(b) Issue Date	Maturity Date	(c) Interest Rate	(d) Principal Amount	Gross Proceeds	(e) Net Proceeds	(f) Currently Outstanding	(g) Yield to Maturity	Annual Interest Cost	Amortization of Debt Disc Premium and Expense	Total Cost	Weighted Average Cost	(h) Affiliate Ownership
1																
2	MT	FMB	6.34% Series Due 2019	03/26/2009	04/01/2019	6.340%	250,000,000	249,832,500	248,207,500	249,945,562	6.344%	15,850,000	664,170	16,514,170	6.61%	n/a
3	MT	FMB	5.71% Series, Due 2039	10/15/2009	10/15/2039	5.710%	55,000,000	55,000,000	54,615,000	55,000,000	5.710%	3,140,500	18,345	3,158,845	5.74%	n/a
4	MT	FMB	5.01% Series, Due 2025	05/27/2010	05/01/2025	5.010%	161,000,000	161,000,000	160,240,796	161,000,000	5.010%	8,066,100	519,742	8,585,842	5.33%	n/a
5	MT	FMB	4.15% Series, Due 2042	08/10/2012	08/10/2042	4.150%	60,000,000	60,000,000	59,659,980	60,000,000	4.150%	2,490,000	12,562	2,502,562	4.17%	n/a
6	MT	FMB	4.30% Series, Due 2042	08/10/2012	08/10/2052	4.300%	40,000,000	40,000,000	39,773,320	40,000,000	4.300%	1,720,000	6,280	1,726,280	4.32%	n/a
7	MT	FMB	4.85% Series, Due 2043	12/19/2013	12/19/2043	4.850%	15,000,000	15,000,000	14,940,000	15,000,000	4.850%	727,500	3,147	730,847	4.87%	n/a
8	MT	FMB	3.99% Series, Due 2028	12/19/2013	12/19/2028	3.990%	35,000,000	35,000,000	34,860,000	35,000,000	3.990%	1,396,500	12,843	1,409,343	4.03%	n/a
9	MT	FMB	4.176% Series, Due 2044	11/15/2014	11/15/2044	4.176%	450,000,000	450,000,000	446,062,500	450,000,000	4.176%	18,792,000	778,295	19,570,295	4.35%	n/a
10	MT	FMB	3.11% Series, Due 2025	06/23/2015	07/01/2025	3.110%	75,000,000	75,000,000	74,700,000	75,000,000	3.110%	2,332,500	410,871	2,743,371	3.66%	n/a
11	MT	FMB	4.11% Series, Due 2045	06/23/2015	07/01/2045	4.110%	125,000,000	125,000,000	124,500,000	125,000,000	4.110%	5,137,500	228,262	5,365,762	4.29%	n/a
12	MT	PCB's	2.00% Series, Due 2023	08/11/2016	08/01/2023	2.000%	144,660,000	144,660,000	144,081,360	144,660,000	2.000%	2,893,200	737,088	3,630,288	2.51%	n/a
13	MT	Unsecured	1.146% New Market Tax Credit			1.146%	1,000,000	1,000,000	955,967	1,000,000	1.146%	11,460	1,066	12,526	1.25%	n/a
14	MT	C.Lease	Capital Leases *				none[1]			none						
15																
16			**MT Total Utility Long-Term Debt**							**$1,411,605,562**		**$62,557,260**	**$3,392,671**	**$65,949,931**	**4.67%**	
17																
18																
19	* MT Total Utility Long-Term Debt comprised of all debt with the MT Jurisdiction, excluding the Basin Creek power purchase agreement which is classified as a capital lease per FAS 13.															
20																
21	**RECONCILIATION TO CONSOLIDATED DEBT AS OF 12/31/2015**															
22																
23			SD Total Utility													
24	SD	FMB	6.05% Series, Due 2018	5/1/2008	5/1/2018	6.050%	55,000,000	55,000,000	54,780,000	55,000,000	6.050%	3,327,500	198,553	3,526,053	6.41%	n/a
25	SD	FMB	5.01% Series, Due 2025	5/27/2010	5/1/2025	5.010%	64,000,000	64,000,000	63,744,000	64,000,000	5.010%	3,208,400	203,707	3,410,107	5.33%	n/a
26	SD	FMB	4.15% Series, Due 2042 (SD)	8/10/2012	8/10/2042	4.150%	30,000,000	30,000,000	29,880,000	30,000,000	4.150%	1,245,000	6,308	1,251,308	4.17%	n/a
27	SD	FMB	4.30% Series, Due 2052 (SD)	8/10/2012	8/10/2052	4.300%	20,000,000	20,000,000	19,920,000	20,000,000	4.300%	860,000	3,153	863,153	4.32%	n/a
28	SD	FMB	4.85% Series, Due 2043 (SD)	12/19/2013	12/19/2043	4.850%	50,000,000	50,000,000	49,800,000	50,000,000	4.850%	2,425,000	10,166	2,435,166	4.87%	n/a
29	SD	FMB	4.22% Series, Due 2044 (SD)	12/19/2014	12/15/2044	4.220%	30,000,000	30,000,000	29,880,000	30,000,000	4.220%	1,266,000	6,749	1,272,749	4.24%	n/a
30	SD	FMB	4.26% Series (PP) ($70M), Due 2040	9/29/2015	9/29/2040	4.260%	70,000,000	70,000,000	69,720,000	70,000,000	4.260%	2,982,000	1,020	2,983,020	4.26%	n/a
31	SD		Old NPS PCB's										49,192	49,192		n/a
32																
33			SD Total Utility Long-Term Debt							$319,000,000		$15,311,900	$478,849	$15,790,749	4.95%	
34																
35		Total NorthWestern Long-Term Debt								1,730,605,562		77,869,160	3,871,520	$81,740,680	4.72%	
36		Add back:														
37	MT	Unsecured	1.146% New Market Tax Credit [1]			1.146%	25,976,900	25,976,900	24,833,058	25,976,900	1.146%	297,695	27,704	325,399	1.25%	n/a
38	MT	PCB's	4.65% Series, Due 2023 August 2016 Paydown							25,545,000						
39																
40		**CONSOLIDATED LONG-TERM DEBT AS OF 12/31/2015 (Ties to 10-K, excluding capital leases)**								**$1,782,127,462**						
41																
42																
43	[1] $26.0 million of $27.0 million total New Market Tax Credit financing not deemed to be obligation of NorthWestern as explained in Mr. Daniel L. Rausch's prefiled direct testimony.															

NORTHWESTERN ENERGY
MONTANA NATURAL GAS CONSOLIDATED UTILITY FILING
Rate Base Asset as Capitalization

LINE	MONTANA 12/31/15 RATE BASE: (Source: Exhibit__(CDL-1) and Annual Report - Schedule 27)	
1		
2	Total Natural Gas Transportation, Distribution, Storage and Production Rate Base (Exhibit__(CDL-1) Column (L) Line 33)	$ 432,088,683
3	Add Back: Regulatory Plant Adjustment per Stipulation (Exhibit__(CDL-1) Column (G) Line 33)	10,456,297
4	Adjusted Total Natural Gas Utility Rate Base	$ 442,544,979
5		
6	Total Electric Transmission, Distribution, and Generation Rate Base (Schedule 27 Line 41)	$ 2,189,420,566
7	Add Back: Regulatory Plant Adjustment per Stipulation (Schedule 27 Line 39)	20,801,999
8	Total Electric Utility Rate Base	$ 2,210,222,565
9		
10	TOTAL MONTANA UTILITY RATE BASE	$ 2,652,767,544

NORTHWESTERN ENERGY

Capital Structure and Rate of Return

MONTANA NATURAL GAS PRODUCTION ASSETS TRUE-UP FILING

Test Year ending December 31, 2013

(Thousands of Dollars)

Bear Paw - NFR	Amount	Percent of Capitalization	Rate	Rate of Return
Total Montana Utility Long-Term Debt	$936,125	53.87%	5.60%	3.02%
Derived Regulated Equity *	801,623	46.13%	10.00% **	4.61%
Total Montana Utiilty Rate Base	$1,737,748	100.00%		7.63%

South Bear Paw - Devon	Amount	Percent of Capitalization	Rate	Rate of Return
Total Montana Utility Long-Term Debt	$936,125	53.87%	5.60%	3.02%
Derived Regulated Equity *	801,623	46.13%	9.80% **	4.52%
Total Montana Utiilty Rate Base	$1,737,748	100.00%		7.54%

* Regulated Equity is equal to Total Montana Utility Rate Base as Capitalization (Exhibit__DLR-6, Line 12) less Total Montana Utility Long-Term Debt

** The rates of return on equity are based on the then authorized ROEs as explained in Mr. Daniel L. Rausch's prefiled direct testimony

NORTHWESTERN ENERGY
MONTANA NATURAL GAS PRODUCTION ASSETS TRUE UP FILING
MONTANA TOTAL UTILITY LONG-TERM DEBT

December 31, 2013

Line No.	Jurisdiction	Type	(a) Issue Title	(b) Issue Date	Maturity Date	(c) Interest Rate	(d) Principal Amount	Gross Proceeds	(e) Net Proceeds	(f) Currently Outstanding	(g) Yield to Maturity	Annual Interest Cost	Amortization of Debt Disc Premium and Expense	Total Cost	Weighted Average Cost	(h) Affiliate Ownership
1																
2	MT	PCB's	4.65% Series, Due 2023	05/09/2006	08/01/2023	4.650%	170,205,000	170,205,000	165,179,180	170,205,000	4.791%	7,914,533	553,322	8,467,855	4.98%	n/a
3	MT	FMB	6.04% Series, Due 2016	09/13/2006	09/01/2016	6.040%	150,000,000	149,926,500	148,169,700	149,979,482	6.043%	9,060,000	248,114	9,308,114	6.21%	n/a
4	MT	FMB	6.34% Series Due 2019	03/26/2009	04/01/2019	6.340%	250,000,000	249,832,500	248,207,500	249,912,980	6.344%	15,850,000	664,170	16,514,170	6.61%	n/a
5	MT	FMB	5.71% Series Due 2039	10/15/2009	10/15/2039	5.710%	55,000,000	55,000,000	54,615,000	55,000,000	5.710%	3,140,500	18,345	3,158,845	5.74%	n/a
6	MT	FMB	5.01% Series, Due 2025	05/27/2010	05/01/2025	5.010%	161,000,000	161,000,000	160,240,796	161,000,000	5.010%	8,066,100	519,742	8,585,842	5.33%	n/a
7	MT	FMB	4.15% Series, Due 2042	08/10/2012	08/10/2042	4.150%	60,000,000	60,000,000	59,659,980	60,000,000	4.150%	2,490,000	12,562	2,502,562	4.17%	n/a
8	MT	FMB	4.30% Series, Due 2042	08/10/2012	08/10/2052	4.300%	40,000,000	40,000,000	39,773,320	40,000,000	4.300%	1,720,000	6,280	1,726,280	4.32%	n/a
9	MT	FMB	4.85% Series, Due 2043	12/19/2013	12/19/2043	4.850%	15,000,000	15,000,000	14,940,000	15,000,000	4.850%	727,500	3,147	730,647	4.87%	n/a
10	MT	FMB	3.99% Series, Due 2028	12/19/2013	12/19/2028	3.990%	35,000,000	35,000,000	34,860,000	35,000,000	3.990%	1,396,500	12,843	1,409,343	4.03%	n/a
11	MT	C.Lease	Capital Leases *			4.400%	27,627			27,627		1,216	0	1,216	4.40%	n/a
12																
13			**MT Total Utility Long-Term Debt**							**$936,125,089**		**$50,366,348**	**$2,038,525**	**$52,404,873**	**5.60%**	
14																
15																
16	* MT Total Utility Long-Term Debt comprised of all debt with the MT Jurisdiction, excluding the Basin Creek power purchase agreement which is classified as a capital lease per FAS 13.															
17																
18	**RECONCILIATION TO CONSOLIDATED DEBT AS OF 12/31/2013**															
19																
20			SD Total Utility													
21	SD	FMB	6.05% Series, Due 2018	5/1/2008	5/1/2018	6.050%	55,000,000	55,000,000	54,780,000	55,000,000	6.050%	3,327,500	198,553	3,526,053	6.41%	n/a
22	SD	FMB	5.01% Series, Due 2025	5/27/2010	5/1/2025	5.010%	64,000,000	64,000,000	63,744,000	64,000,000	5.010%	3,206,400	203,707	3,410,107	5.33%	n/a
23	SD	FMB	4.15% Series, Due 2042 (SD)	8/10/2012	8/10/2042	4.150%	30,000,000	30,000,000	29,880,000	30,000,000	4.150%	1,245,000	6,308	1,251,308	4.17%	n/a
24	SD	FMB	4.30% Series, Due 2052 (SD)	8/10/2012	8/10/2052	4.300%	20,000,000	20,000,000	19,920,000	20,000,000	4.300%	860,000	3,153	863,153	4.32%	n/a
25	SD	FMB	4.85% Series, Due 2043 (SD)	12/19/2013	12/19/2043	4.850%	50,000,000	50,000,000	49,800,000	50,000,000	4.850%	2,425,000	10,166	2,435,166	4.87%	n/a
26	SD		Old NPS PCB's										49,192	49,192		n/a
27																
28			SD Total Utility Long-Term Debt				$219,000,000			$219,000,000		$11,063,900	$471,080	$11,534,980	5.27%	
29																
30		Total NorthWestern Long-Term Debt								1,155,125,089		61,430,248	2,509,605	$63,939,853	5.54%	
31		Less:														
32			MT Capital Leases							27,627						
33																
34		**CONSOLIDATED LONG-TERM DEBT AS OF 12/31/2013 (Ties to 10-K, excluding capital leases)**								**$1,155,097,462**						

NORTHWESTERN ENERGY
MONTANA NATURAL GAS PRODUCTION ASSETS TRUE-UP FILING
Rate Base Asset as Capitalization

LINE	MONTANA 12/31/13 RATE BASE: (Source: Annual Report - Schedule 27)	
1		
2	Total Natural Gas Transportation, Distribution, Storage and Production Rate Base (Schedule 27 Line 42)	$ 372,655,281
3	Adjust for Full Year of Devon [1]: Remove Devon 2013 13-month average rate base	$ (4,746,348)
4	Adjust for Full Year of Devon [1]: Add Devon 2013 year-end rate base (Exhibit__(PJD-4) page 7)	$ 60,643,476
5	Add Back: Regulatory Plant Adjustment per Stipulation (Schedule 27, Line 40)	11,098,508
6	Total Natural Gas Utility Rate Base	$ 439,650,917
7		
8	Total Electric Transmission, Distribution, and Generation Rate Base (Schedule 27 Line 41)	$ 1,275,564,160
9	Add Back: Regulatory Plant Adjustment per Stipulation (Schedule 27, Line 39)	22,533,333
10	Total Electric Utility Rate Base	$ 1,298,097,493
11		
12	TOTAL MONTANA UTILITY RATE BASE	$ 1,737,748,410

[1] Adjusted to reflect full amount of rate base for Devon which was acquired in November 2013. Used Devon's 2013 year-end rate base.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF CRYSTAL D. LAIL

ON BEHALF OF NORTHWESTERN ENERGY

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Exhibits

Natural Gas Rate Base	Exhibit__(CDL-1)
Jurisdictional Allocation of Shared Administrative Costs	Exhibit__(CDL-2)
Electric and Natural Gas Allocation of Shared Administrative Costs	Exhibit__(CDL-3)

1 **Witness Information**

2 **Q. Please state your name and business address.**

3 **A.** My name is Crystal D. Lail. My business address is 3010 West 69th Street,

4 Sioux Falls, South Dakota, 57108.

5

6 **Q. By whom are you employed and in what capacity?**

7 **A.** I am the Vice President and Controller of NorthWestern Corporation

8 ("NorthWestern").

9

10 **Q. Please summarize your educational and employment experiences.**

11 **A.** I have been with NorthWestern since January 2003. My primary

12 responsibilities include, among other duties, overseeing compliance with

13 financial reporting requirements established by the Securities and Exchange

14 Commission ("SEC") and other regulatory agencies, technical research with

15 regard thereto, reviewing NorthWestern's financial statements, and

16 implementing and overseeing accounting policies and procedures.

17 Previously, I was an auditor with KPMG. I have a Bachelor of Science in

18 Business Administration degree from Evangel University and am a Certified

19 Public Accountant.

20

21 **Purpose of Testimony**

22 **Q. What is the purpose of your testimony?**

23 **A.** My testimony:

1. Provides an attestation as to the accuracy of the actual accounting data submitted as part of this filing;
2. Explains the development of the rate base and the associated book depreciation and depletion expense for the Bear Paw (NFR) Natural Gas Production assets for the years 2013 through 2015 as part of this filing;
3. Explains the development of the rate base and the associated book depreciation and depletion expense for the South Bear Paw (Devon) Natural Gas Production assets for the years 2014 through 2015 as part of this filing;
4. Explains the development of the test period rate base and the associated book depreciation expense for the Montana Natural Gas Utility for this filing; and
5. Discusses NorthWestern's method of allocating shared administrative costs.

Attestation of the Accuracy of the Actual Accounting Data

Q. As the Officer responsible for accounting policies and procedures during the test period, do you attest to the accuracy of the actual accounting data presented in NorthWestern's application as required by the Montana Public Service Commission's ("MPSC" or "Commission") filing requirement found in ARM 38.5.112?

A. Yes. My attestation as to accuracy extends to those documents presenting actual accounting data. In particular, I attest to the accuracy of:

- the actual data contained in the Bear Paw (NFR) Natural Gas Production asset cost of service presentation for years 2013 through 2015 shown on Exhibits__(PJD-1) through (PJD-3) accompanying the Prefiled Direct Testimony of Patrick J. DiFronzo ("DiFronzo Direct Testimony");
- the actual data contained in the South Bear Paw (Devon) Natural Gas Production asset cost of service presentation for years 2014 through 2015 shown on Exhibits__(PJD-4) and (PJD-5) accompanying the DiFronzo Direct Testimony;
- the actual data contained in the cost of service presentation for the year 2015 shown on Exhibit__(PJD-11) and Exhibits__(PJD-13) through (PJD-15) accompanying the DiFronzo Direct Testimony;
- the actual plant account and depreciation reserve data for the 2015 test period shown on my Exhibit__(CDL-3); and
- the income statement, balance sheet, utility plant accounts, depreciation reserve statements and workpapers, and capitalization and other statements and workpapers portraying actual, unadjusted data for the year ending December 31, 2015 that is contained in the information filed in this docket pursuant to the Commission's rate case filing requirement rules (ARM 38.5.101, et seq.).

Rate Base Exhibit

Q. Have you prepared an exhibit on this subject for this filing?

1 **A.** Yes. I have prepared Exhibit__(CDL-1), which presents the test period
2 Montana Natural Gas Utility rate base, including the Gas Production assets
3 Bear Paw (NFR), South Bear Paw (Devon), and Battle Creek, as well as the
4 plant adjustment associated with the Stipulation Agreement approved in Final
5 Order No. 6852f in Docket No. D2007.7.82 ("Stipulation Agreement"). The
6 Stipulation Agreement is discussed in more detail below. The Montana
7 Natural Gas Utility rate base has been computed on a 13-month average
8 basis.
9
10 **Q. Please define the test period utilized by NorthWestern in this Natural**
11 **Gas Utility Application.**
12 **A.** The test period in this Application is the historical calendar year ended
13 December 31, 2015, adjusted for known and measurable changes occurring
14 in the 12 months after December 31, 2015. This test period complies with the
15 Commission's ARM 38.5.106. In addition, this filing includes the Bear Paw
16 (NFR) Natural Gas Production asset cost of service presentation for years
17 2013 through 2015 and the South Bear Paw (Devon) Natural Gas Production
18 asset cost of service presentation for years 2014 through 2015.
19
20 **Test Period Natural Gas Rate Base**
21 **Q. Please describe in detail Exhibit__(CDL-1) and the source of the**
22 **information it presents.**

1 **A.** Column (A) of Exhibit__(CDL-1) presents the actual 13-month average rate
2 base as of December 31, 2015 for the Montana Natural Gas Utility. The
3 source of Column (A) is the books and records of NorthWestern. This 2015
4 actual 13-month average rate base was then adjusted to reflect the following
5 known and measurable changes:

6 • The adjustment shown under Column (B) reflects total changes to
7 the accumulated depreciation and depletion reserves associated
8 with normalizing adjustments that reflect depreciation at updated
9 accrual rates based upon the Depreciation Technical Update
10 performed by our consultants, Foster Associates, Inc. In addition,
11 the adjustment incorporates normalizing adjustments made to
12 depletion expense to reflect revised depletion rates as noted below.

13 • The adjustment shown under Column (F) reflects the inclusion of
14 the actual 13-month average rate base as of December 2015 for
15 the Canadian Montana Pipeline Company ("CMPL"). CMPL is
16 wholly owned by NorthWestern and was established to handle the
17 cross border importation of Canadian natural gas. CMPL plant
18 includes approximately 4 miles of 16-inch pipeline with associated
19 controls and communication equipment.

20 • The adjustment shown under Column (G) reflects the allocated
21 natural gas portion of the reduction to rate base associated with the
22 Stipulation Agreement which provides for a reduction in both the
23 natural gas and electric rate bases associated with total capital

expenditures of $19.4 million in each of the years 2008 and 2009 ($38,800,000 total). This total is allocated one-third to natural gas delivery service and two-thirds to electric delivery service pursuant to Section II.1.d of the Stipulation Agreement. The net amount of the reduction to the natural gas and electric rate bases declines over time to reflect the annual increase to the accumulated depreciation reserve associated with the annual depreciation expense calculated on this $38,800,000 of plant. These reductions to rate base will be in effect from 2009 through 2039 pursuant to the Stipulation Agreement. Also included as an adjustment under Column (G) is a reduction to rate base associated with the allocable gas portion of the New Markets Tax Credit associated with NorthWestern's new general office building. A total tax credit of $7,851,305 is associated with the building. This credit is expected to reduce the amount of debt associated with the building at the end of a seven-year period after completion of construction, which was completed in December of 2015. As such, the gas allocation of the 13-month average for the credit has been included as a known adjustment.

- Column (H) is a sub-total for the Natural Gas rate base.
- The adjustment shown under Column (I) reflects the changes to deferred income taxes explained in the Prefiled Direct Testimony of Wayne M. Hitt.

- The adjustment shown under Column (J) reflects the inclusion of a regulatory asset attributable to the under-collections associated with the MPSC and Montana Consumer Counsel ("MCC") taxes. The tax expenses for 2015 have been included as a known adjustment.
- The adjustment shown under Column (K) reflects the changes to working capital associated with the gross cash requirement. The test period gross cash requirement for the natural gas rate base was calculated using the net lag days from the 2016 Lead/Lag study, the test period Operation and Maintenance ("O&M") expenses and NorthWestern's proposed capital structure components.
- Column (I) is the Montana Natural Gas Utility rate base as of December 31, 2015, adjusted for these known and measurable changes.

Q. Have you made any other changes to the 2015 year-end rate base amounts?

A. Yes. Statement C includes an adjustment to the December 31, 2015 year-end balance to reclassify $2,270,924 of plant from gas transmission to gas storage plant. At year-end, $2,270,942 of total assets associated with a new gas storage compressor installed at the Cobb Storage facility were placed into service. These assets were inadvertently included in gas transmission

plant, as opposed to gas storage plant. Upon closing the work order during 2016, it was determined the storage assets had been incorrectly recorded to transmission plant and were, appropriately, reclassified as storage plant. This filing is adjusted to reflect the accurate presentation of the $2,270,924 additions to gas storage plant.

Q. How has the Montana common utility plant and depreciation reserve been allocated to and included in the Montana Natural Gas Utility rate base?

A. The allocation factors shown in Statement D of this filing were used to allocate the individual facilities included in common utility plant to the Montana Natural Gas Utility rate base. The associated depreciation reserve applicable to the common plant was also allocated based on these allocation factors.

Bear Paw (NFR) Rate Base

Q. Please address the basis NorthWestern used for determining the asset value of Bear Paw (NFR) in its revenue requirement computation.

A. The Utility Plant in Service section on page 1 of Exhibit__(PJD-1), Exhibit__(PJD-2), and Exhibit__(PJD-3) of the DiFronzo Direct Testimony includes the Bear Paw (NFR) Plant or asset value of $16,927,969 on line 5 and on page 7 of the exhibits. This figure represents the purchase price for the Bear Paw (NFR) properties, including a $3,088,407 reduction in plant for

the removal of oil wells that were subsequently sold. The Prefiled Direct Testimony of Patrick E. Callahan ("Callahan Direct Testimony") provides an explanation of NorthWestern's purchase of the Bear Paw (NFR) properties, including discussion regarding the oil well sale.

South Bear Paw (Devon) Rate Base

Q. Please address the basis NorthWestern used for determining the asset value of South Bear Paw (Devon) in its revenue requirement computation.

A. The Utility Plant in Service section on page 1 of Exhibit__(PJD-4) and Exhibit__(PJD-5) of the DiFronzo Direct Testimony includes the South Bear Paw (Devon) Plant or asset value of $61,709,882 on line 5 and on page 7 of the exhibits. This figure represents the purchase price for the South Bear Paw (Devon) properties. The Callahan Direct Testimony provides an explanation of NorthWestern's purchase of the South Bear Paw (Devon) properties.

Test Period Depreciation & Depletion Expense

Q. Please describe how the Accumulated Depreciation & Depletion was developed.

A. Accumulated Depreciation was developed utilizing straight line depreciation rates as calculated by our consultants, Foster Associates, Inc. in the 2012 Depreciation Rate Study, with asset lives ranging from 39 to 50 years for the

Field Structures, Lines, Compressor Equipment, Measuring and Regulating Equipment and Dehydration Equipment as shown on page 6 of Exhibit__(PJD-1), Exhibit__(PJD-2), and Exhibit__(PJD-3). Depletion is calculated for the Gas Leasehold and Producing Well Construction and Equipment at a rate based upon the net plant book value and expectations of total gas reserves available and is based on 12 months of actual production for each year. For example, the depletable net plant book value for Bear Paw (NFR) was $10,130,595 at December 31, 2014. Expected gas production from Bear Paw (NFR) wells remaining as of January 1, 2015 was 9,055,709 per thousand standard cubic feet ("mcf"), which calculates to a depletion rate of $1.12/mcf of Bear Paw (NFR) gas production.

Q. How was the test period depreciation expense calculated?

A. The test period depreciation expense was taken directly from NorthWestern's 2015 books and records. The annual depreciation expense is calculated within NorthWestern's Power Plant Fixed Asset system. The actual 2015 accrual was calculated by applying NorthWestern's 2012 Montana Depreciation Study accrual rates to the December 2014 plant balances.

Q. How was the test period depletion expense calculated?

A. The test period depletion expense was taken directly from NorthWestern's 2015 books and records. The annual depletion expense is calculated within NorthWestern's Power Plant Fixed Asset system. The Gas Leasehold and

1 Producing Well Construction and Equipment are being depleted at different
2 rates for each production facility, based upon the plant cost and expectations
3 of total gas reserves available.
4
5 **Q. Did you make any known change adjustments to depreciation or**
6 **depletion expense?**
7 **A.** A normalizing adjustment is presented within Statement I for changes to the
8 actual 2015 accrual associated with updated accrual rates obtained from our
9 consultants, Foster Associates, Inc. as part of the 2016 Depreciation Rate
10 Technical Update to the 2012 study. The technical update supports natural
11 gas depreciation rates, and common rates are supported by the 2012 study.
12 The amount of this adjustment increases depreciation expense and
13 accumulated depreciation by $259,314.
14
15 In addition, a normalizing adjustment is presented within Statement I for
16 changes to the actual 2015 depletion rates to adjust the manner in which
17 NorthWestern was calculating the depletion rates in 2015. Prior to reflecting
18 the normalizing adjustment, depletion rates were calculated by dividing the
19 natural gas leasehold and producing well asset values by the expected gas
20 reserves. This rate was updated, periodically, as the amount of estimated
21 gas reserves available was estimated. The normalizing adjustment calculates
22 the depletion rate by dividing the natural gas leasehold and producing well net
23 asset value by the expected gas reserves and, appropriately, reflects a

reduction to depletion expense for the change in methodology to calculate the depletion rate. The amount of this adjustment decreases depletion expense and accumulated depletion by $346,655.

The normalized depletion amounts for Bear Paw (NFR) for 2013 – 2015 are presented in the table below.

	Production	Est. Reserve Balance	Depletion Rate	Depletion Expense
2013	1,402,532	11,919,403	1.38	1,930,809.38
2014	1,362,983	10,418,692	1.12	1,519,841.09
2015	1,113,310	9,055,709	1.12	1,245,456.56

The normalized depletion amounts for South Bear Paw (Devon) for years 2014-2015 are presented in the table below.

	Production	Est. Reserve Balance	Depletion Rate	Depletion Expense
2014	4,929,506	57,546,215	1.05	5,176,977.24
2015	4,349,031	52,616,709	0.99	4,290,803.81

Q. Have you calculated any of the amortization expense items included in the Income Statements?

A. Yes. The amortization expense items calculated are detailed on work papers included in Statement I of this filing. Witness Patrick DiFronzo is responsible for the non-rate base related items and I am responsible for the rate base related items as detailed in the work papers.

Forecast Depreciation and Depletion

Q. Please address the basis used for determining the depreciation, depletion and rate base included in the 2016 – 2019 Battle Creek, Bear Paw (NFR) and South Bear Paw (Devon) forecasted revenue requirement.

A. The Depreciation was developed utilizing straight line depreciation rates as calculated by our consultants, Foster Associates, Inc. as part of the 2016 Depreciation Technical Update, with depreciable lives ranging from 39 to 50 years for the Field Structures, Lines, Compressor Equipment, Measuring and Regulating Equipment and Dehydration Equipment as shown on page 6 of Exhibit__(PJD-8), Exhibit__(PJD-9), and Exhibit__(PJD-10). The projected year-end balances for each of the 2016-2019 forecast years was calculated based upon incorporating forecasted additions as part of NorthWestern's five-year capital forecast and an estimate of asset retirements during that time. The Gas Leasehold and Producing Well Construction and Equipment are depleted at different rates for each production facility, based upon the plant net book value and expectations of total gas reserves available. Those rates are calculated based upon forecasted production volumes and gas reserve estimates and are included in the Battle Creek, Bear Paw (NFR), and South Bear Paw (Devon) tables below.

The following table reflects total forecasted Battle Creek depletion for 2016-2019, as shown in Exhibit__(PJD-8).

	Production	Est. Reserve Balance	Depletion Rate	Depletion Expense
2016	325,000	6,037,000	1.37	445,663.79
2017	293,000	5,712,000	1.38	403,025.53
2018	268,000	5,419,000	1.38	369,814.34
2019	245,000	5,151,000	1.39	339,470.53

The following table reflects total forecasted Bear Paw (NFR) depletion for 2016-2019, as shown in Exhibit__(PJD-9).

	Production	Est. Reserve Balance	Depletion Rate	Depletion Expense
2016	974,000	9,330,000	0.99	961,023.38
2017	868,000	8,356,000	0.99	859,992.28
2018	770,000	7,488,000	1.00	766,354.70
2019	690,000	6,718,000	1.00	690,988.36

The following table reflects total forecasted South Bear Paw (Devon) depletion for 2016-2019, as shown in Exhibit___(PJD-10).

	Production	Est. Reserve Balance	Depletion Rate	Depletion Expense
2016	4,025,000	48,706,000	0.98	3,925,683.60
2017	3,686,000	44,681,000	0.98	3,604,984.77
2018	3,391,000	40,995,000	0.98	3,326,254.92
2019	3,130,000	37,604,000	0.98	3,082,368.71

Allocation of Shared Administrative Costs

Q. Please briefly describe the methods used to allocate costs to Montana Natural Gas operations.

A. NorthWestern has three regulatory jurisdictions consisting of Montana, South Dakota, and Nebraska. NorthWestern's administrative costs are allocated

between jurisdictions using a three-factor formula, consisting of gross plant, margin, and operation and maintenance labor expense. The three-factor formula is updated annually in October through an internal administrative allocation study. The 2015 jurisdictional allocation methodology is attached as Exhibit__(CDL-2).

In addition, NorthWestern uses a three-factor formula to allocate shared costs between Montana electric and natural gas operations consisting of plant, customers, and operation and maintenance labor expense for each of the electric, natural gas, and propane segments of its business. This formula is also updated annually in October through an internal administrative allocations study. The 2015 electric and natural gas allocation methodology is attached as Exhibit__(CDL-3).

Finally, NorthWestern uses operation and maintenance labor expense to allocate shared costs to profit centers within the electric and natural gas segments. This formula is also updated annually in October through an internal administrative allocations study. The 2015 electric and natural gas profit center allocation methodology is included in Exhibit__(CDL-3). These allocation methods were approved in our most recent natural gas filing, Docket No. D2012.9.94.

1 The following table reflects the impact of applying the allocation methodology
2 consistent with the approval in the last natural gas docket, which results in an
3 overall 2% reduction to the natural gas utility from the last rate case. In
4 addition, prior to this filing, shared administrative costs were allocated to
5 Transmission, Distribution, and Storage. With this filing, shared
6 administrative costs are also allocated to Gas Production.

	Natural Gas			Electric
Allocation of Shared Administrative Costs	Transmission, Distribution & Storage	Production	Total	Total
2012 test period in Docket No. D2012.9.94	31%		31%	69%
2015 test period	25%	4%	29%	71%
2016 period	24%	5%	29%	71%
Normalizing Adjustments	-1%	1%	-	-

7 Our natural gas segment includes a Production Administration profit center
8 that represents the allocation of shared costs for Battle Creek, Bear Paw
9 (NFR), South Bear Paw (Devon), and Havre Pipeline Company, LLC ("HPC").
10 Exhibit__(PJD-16) accompanying the DiFronzo Direct Testimony reflects the
11 breakout of the Production Administration profit center to Battle Creek, Bear
12 Paw (NFR), and South Bear Paw (Devon), with the remainder representing
13 HPC, which is not included in this filing. Accordingly, South Bear Paw
14 (Devon)'s overhead charge to HPC, which is reflected as a negative expense

on South Bear Paw (Devon)'s Income Statement, has been removed from all South Bear Paw (Devon) Income Statements presented in this filing.

In addition to the expense allocations described above, common plant and common depreciation are allocated between electric and natural gas using rate base percentages. The 2015 allocation percentage to natural gas was 29%.

Q. Have there been any changes to the allocation percentages from the test period?

A. Yes. While the jurisdictional allocation of 71% electric and 29% natural gas remained the same for 2015 and 2016, the natural gas intra-segment allocation changed in 2016. This resulted in a 1% decrease in allocation to transmission, distribution, and storage, and a 1% increase to gas production. As such, the Corporate Allocation column in Exhibit__(PJD-11) and Exhibits__(PJD-13) through (PJD-15) accompanying the DiFronzo Direct Testimony reflects this change as a normalizing adjustment.

Q. Does this complete your testimony?

A. Yes, it does.

NORTHWESTERN ENERGY - MONTANA GAS UTILITY RATE BASE - 13 MONTH AVERAGE

NORTHWESTERN ENERGY COMPANY

LINE	DESCRIPTION	(A) ACTUAL 13 MONTH AVERAGE RATE BASE 12/31/15	(B) TD&S NORMALIZING ADJUSTMENTS	(C) BATTLE CREEK	(D) BEAR PAW	(E) SOUTH BEAR PAW	(F) CMPL	(G) REGULATORY PLANT ADJ	(H) SUB-TOTAL	(I) TD&S DEFERRED TAXES	(J) OTHER	(K) WORKING CAPITAL	(L) TEST PERIDD 12/31/15 ADJUSTED	LINE
1	UTILITY PLANT IN SERVICE													1
2	Gas	617,024,475		12,395,450	16,080,164	61,756,259	370,973	-10,245,761	697,381,560				697,381,560	2
3	Common	29,127,408		640,212	830,524	3,189,648		-210,536	33,577,257				33,577,257	3
4	TOTAL UTILITY PLANT IN SERVICE	646,151,883		13,035,662	16,910,688	64,945,907	370,973	-10,456,297	730,958,817				730,958,817	4
5														5
6	ACCUMULATED DEPRECIATION													6
7	Gas	261,810,409	121,916	3,189,723	4,185,519	7,489,547	287,258	0	277,084,372				277,084,372	7
8	Common	11,471,503		252,141	327,093	1,256,207			13,306,944				13,306,944	8
9	TOTAL ACCUMULATED DEPRECIATION	273,281,912	121,916	3,441,864	4,512,612	8,745,754	287,258	0	290,391,316				290,391,316	9
10														10
11	TOTAL NET PLANT	372,869,970	-121,916	9,593,799	12,398,077	56,200,153	83,715	-10,456,297	440,567,501				440,567,501	11
12														12
13														13
14	GAS STORED UNDERGROUND	32,096,313							32,096,313				32,096,313	14
15	COST OF REFINANCING DEBT	4,044,903							4,044,903				4,044,903	15
16	GAS STORAGE SALES 2000 & 2001 (9-2039)	-10,199,816							-10,199,816				-10,199,816	16
17	REGULATORY ASSET FAS 109	61,269,439							61,269,439				61,269,439	17
18	MPSC/MCC TAXES	130,100		-582					129,518		163,570		293,088	18
19														19
20														20
21	LESS: CUSTOMER CONTRIBUTED CAPITAL													21
22	Accumulated Deferred Income Taxes													22
23	See Page 2 for Details	72,628,130		738,103	-41,916	2,846,250			76,170,567	-1,401,486	0		74,769,081	23
24	Personal Injury & Property Damage	3,065,278							3,065,278				3,065,278	24
25	Customer Advances for Construction	6,813,187							6,813,187				6,813,187	25
26	TOTAL CUSTOMER CONTRIBUTEO CAPITAL	82,506,595	0	738,103	-41,916	2,846,250	0	0	86,049,032	-1,401,486	0		84,647,546	26
27														27
28	PLUS: WORKING CAPITAL													28
29	Gross Cash Requirements	-13,582,217							-13,582,217			-4,835,508	-18,417,725	29
30	Materials and Supplies	7,085,112							7,085,112				7,085,112	30
31	TOTAL WORKING CAPITAL	-6,497,105							-6,497,105			-4,835,508	-11,332,613	31
32														32
33	TOTAL GAS UTILITY RATE BASE	371,207,209	-121,916	8,855,114	12,439,993	53,353,904	83,715	-10,456,297	435,361,722	1,401,486	163,570	-4,835,508	432,091,269	33

1	Accumulated Deferred Income Taxes													1
2	Regulatory Liability - MPSC Taxes	101,752		-245	-378	-708			100,421				100,421	2
3	Accelerated Depreciation	35,511,306		665,268	654,837	2,083,596			38,915,006	1,501,507			40,416,513	3
4	Customer Advances for Construction	-2,657,343		-1,733	-2,685	-5,020			-2,666,781				-2,666,781	4
5	Net Operating Loss	-4,725,381		99,162	-655,957	838,922			-4,443,254	-2,902,993			-7,346,247	5
6	Deferred Revenue	-5,438,428		-19,345	-29,977	-56,041			-5,541,789				-5,541,789	6
7	Accrued Incentive Compensation	-691,258		-1,070	-1,658	-3,099			-697,085				-697,085	7
8	Injuries & Damages	-972,246		1,758	2,724	5,093			-962,671				-962,671	8
9	Cost of Refinancing Debt	-197,470		-521	-808	-1,510			-200,308				-200,309	9
10	Property Taxes	5,216		0	0	0			5,216				5,216	10
11	FAS 106 & FAS 112 Post Retirements Benefits	-9,088,186		-4,742	-7,348	-13,737			-9,114,013				-9,114,013	11
12	Environmental Reserve	-491,273		-430	-666	-1,246			-493,615				-493,615	12
13	Regulatory Asset FAS 109	61,269,439		0	0	0			61,269,439				61,269,439	13
14											0			14
15	Total Deferred Income Taxes	72,628,130	0	738,103	-41,916	2,846,250	0	0	76,170,567	-1,401,486	0	0	74,769,081	15

NORTHWESTERN ENERGY - MONTANA TRANSMISSION & DISTRIBUTION RATE BASE - 13 MONTH AVERAGE

NORTHWESTERN ENERGY COMPANY

LINE	DESCRIPTION	(A) ACTUAL 13 MONTH AVERAGE RATE BASE 12/31/15	(B) REGULATORY PLANT ADJ	(C) SUB-TOTAL	(D) TD&S NORMALIZING ADJUSTMENTS	(I) DEFERRED TAXES	(J) OTHER	(K) WORKING CAPITAL	(L) TEST PERIOD 12/31/15 ADJUSTED	LINE
1	UTILITY PLANT IN SERVICE									1
2	Gas	617,024,475	-10,245,761	606,778,714					606,778,714	2
3	Common	29,127,408	-210,536	28,916,872					28,916,872	3
4	TOTAL UTILITY PLANT IN SERVICE	646,151,883	-10,456,297	635,695,586					635,695,586	4
5										5
6	ACCUMULATED DEPRECIATION									6
7	Gas	261,810,409	0	261,810,409	121,916				261,932,325	7
8	Common	11,471,503		11,471,503					11,471,503	8
9	TOTAL ACCUMULATED DEPRECIATION	273,281,912	0	273,281,912	121,916				273,403,828	9
10										10
11	TOTAL NET PLANT	372,869,970	-10,456,297	362,413,674	-121,916				362,291,758	11
12										12
13										13
14	GAS STORED UNDERGROUND	32,096,313		32,096,313					32,096,313	14
15	COST OF REFINANCING DEBT	4,044,903		4,044,903					4,044,903	15
16	GAS STORAGE SALES 2000 & 2001 (9-2039)	-10,199,816		-10,199,816					-10,199,816	16
17	REGULATORY ASSET FAS 109	61,269,439		61,269,439					61,269,439	17
18	MPSC/MCC TAXES	130,100		130,100			163,570		293,670	18
19										19
20										20
21	LESS: CUSTOMER CONTRIBUTED CAPITAL									21
22	Accumulated Deferred Income Taxes									22
23	See Page 2 for Details	72,628,130		72,628,130		-1,401,486	0		71,226,644	23
24	Personal Injury & Property Damage	3,065,278		3,065,278					3,065,278	24
25	Customer Advances for Construction	6,813,187		6,813,187					6,813,187	25
26	TOTAL CUSTOMER CONTRIBUTED CAPITAL	82,506,595	0	82,506,595	0	-1,401,486	0		81,105,109	26
27										27
28	PLUS: WORKING CAPITAL									28
29	Gross Cash Requirements	-13,582,217		-13,582,217				-2,241,586	-15,823,803	29
30	Materials and Supplies	7,085,112		7,085,112					7,085,112	30
31	TOTAL WORKING CAPITAL	-6,497,105		-6,497,105				-2,241,586	-8,736,691	31
32										32
33	TOTAL GAS UTILITY RATE BASE	371,207,209	-10,456,297	360,750,913	-121,916	1,401,486	163,570	-2,241,586	359,952,466	33

1	Accumulated Deferred Income Taxes									1
2	Regulatory Liability - MPSC Taxes	101,752		101,752					101,752	2
3	Accelerated Depreciation	35,511,306		35,511,306		1,501,507			37,012,813	3
4	Customer Advances for Construction	-2,657,343		-2,657,343					-2,657,343	4
5	Net Operating Loss	-4,725,381		-4,725,381		-2,902,993			-7,628,374	5
6	Deferred Revenue	-5,436,426		-5,436,426					-5,436,426	6
7	Accrued Incentive Compensation	-691,258		-691,258					-691,258	7
8	Injuries & Damages	-972,246		-972,246					-972,246	8
9	Cost of Refinancing Debt	-197,470		-197,470					-197,470	9
10	Property Taxes	5,216		5,216					5,216	10
11	FAS 106 & FAS 112 Post Retirements Benefits	-9,088,186		-9,088,186					-9,088,186	11
12	Environmental Reserve	-491,273		-491,273					-491,273	12
13	Regulatory Asset FAS 109	61,269,439		61,269,439					61,269,439	13
14							0			14
15	Total Deferred Income Taxes	72,628,130	0	72,628,130		-1,401,486	0	0	71,226,644	15

NORTHWESTERN ENERGY - BATTLE CREEK RATE BASE - 13 MONTH AVERAGE

NORTHWESTERN ENERGY COMPANY

LINE	DESCRIPTION	(B) BATTLE CREEK	(G) REGULATORY PLANT ADJ	NORMALIZING ADJUSTMENT	(I) DEFERRED TAXES	(J) OTHER	(K) WORKING CAPITAL	(L) TEST PERIOD 12/31/15 ADJUSTED	LINE
1	UTILITY PLANT IN SERVICE								1
2	Gas	12,395,450						12,395,450	2
3	Common	640,212						640,212	3
4	TOTAL UTILITY PLANT IN SERVICE	13,035,662	0					13,035,662	4
5									5
6	ACCUMULATED DEPRECIATION								6
7	Gas	3,250,948	0	-61,225				3,189,723	7
8	Common	252,141						252,141	8
9	TOTAL ACCUMULATED DEPRECIATION	3,503,089	0	-61,225				3,441,864	9
10									10
11	TOTAL NET PLANT	9,532,574	0	61,225				9,593,799	11
12									12
13									13
14	GAS STORED UNDERGROUND							0	14
15	COST OF REFINANCING DEBT							0	15
16	GAS STORAGE SALES 2000 & 2001 (9-2039)							0	16
17	REGULATORY ASSET FAS 109							0	17
18	MPSC/MCC TAXES					-582		-582	18
19									19
20									20
21	LESS: CUSTOMER CONTRIBUTED CAPITAL								21
22	Accumulated Deferred Income Taxes								22
23	See Page 2 for Details	953,444			-215,341	0		738,103	23
24	Personal Injury & Property Damage							0	24
25	Customer Advances for Construction							0	25
26	TOTAL CUSTOMER CONTRIBUTED CAPITAL	953,444	0		-215,341	0		738,103	26
27									27
28	PLUS: WORKING CAPITAL								28
29	Gross Cash Requirements						-241,893	-241,893	29
30	Materials and Supplies							0	30
31	TOTAL WORKING CAPITAL						-241,893	-241,893	31
32									32
33	TOTAL GAS UTILITY RATE BASE	8,579,130	0	61,225	215,341	-582	-241,893	8,613,221	33

1	Accumulated Deferred Income Taxes								1
2	Regulatory Liability - MPSC Taxes				-245			-245	2
3	Accelerated Depreciation	360,878			304,390			665,268	3
4	Customer Advances for Construction				-1,733			-1,733	4
5	Net Operating Loss	592,566			-493,404			99,162	5
6	Deferred Revenue				-19,345			-19,345	6
7	Accrued Incentive Compensation				-1,070			-1,070	7
8	Injuries & Damages				1,758			1,758	8
9	Cost of Refinancing Debt				-521			-521	9
10	Property Taxes							0	10
11	FAS 106 & FAS 112 Post Retirements Benefits				-4,742			-4,742	11
12	Environmental Reserve				-430			-430	12
13	Regulatory Asset FAS 109							0	13
14						0			14
15	Total Deferred Income Taxes	953,444	0		-215,341	0	0	738,103	15

NORTHWESTERN ENERGY - BEAR PAW RATE BASE - 13 MONTH AVERAGE

NORTHWESTERN ENERGY COMPANY

LINE	DESCRIPTION	(B) BEAR PAW	(G) REGULATORY PLANT ADJ	NORMALIZING ADJUSTMENT	(I) DEFERRED TAXES	(J) OTHER	(K) WORKING CAPITAL	(L) TEST PERIOD 12/31/15 ADJUSTED	LINE
1	UTILITY PLANT IN SERVICE								1
2	Gas	16,080,164						16,080,164	2
3	Common	830,524						830,524	3
4	TOTAL UTILITY PLANT IN SERVICE	16,910,688	0					16,910,688	4
5									5
6	ACCUMULATED DEPRECIATION								6
7	Gas	4,287,814	0	-102,295				4,185,519	7
8	Common	327,093						327,093	8
9	TOTAL ACCUMULATED DEPRECIATION	4,614,907	0	-102,295				4,512,612	9
10									10
11	TOTAL NET PLANT	12,295,782	0	102,295				12,398,077	11
12									12
13									13
14	GAS STORED UNDERGROUND							0	14
15	COST OF REFINANCING DEBT							0	15
16	GAS STORAGE SALES 2000 & 2001 (9-2039)							0	16
17	REGULATORY ASSET FAS 109							0	17
18	MPSC/MCC TAXES							0	18
19									19
20									20
21	LESS: CUSTOMER CONTRIBUTED CAPITAL								21
22	Accumulated Deferred Income Taxes								22
23	See Page 2 for Details	838,957			-880,873	0		-41,916	23
24	Personal Injury & Property Damage							0	24
25	Customer Advances for Construction							0	25
26	TOTAL CUSTOMER CONTRIBUTED CAPITAL	838,957	0		-880,873	0		-41,916	26
27									27
28	PLUS: WORKING CAPITAL								28
29	Gross Cash Requirements						-634,495	-634,495	29
30	Materials and Supplies							0	30
31	TOTAL WORKING CAPITAL						-634,495	-634,495	31
32									32
33	TOTAL GAS UTILITY RATE BASE	11,456,825	0	102,295	880,873	0	-634,495	11,805,498	33

1	Accumulated Deferred Income Taxes								1
2	Regulatory Liability - MPSC Taxes				-379			-379	2
3	Accelerated Depreciation	233,987			420,850			654,837	3
4	Customer Advances for Construction				-2,685			-2,685	4
5	Net Operating Loss	604,970			-1,260,927			-655,957	5
6	Deferred Revenue				-29,977			-29,977	6
7	Accrued Incentive Compensation				-1,658			-1,658	7
8	Injuries & Damages				2,724			2,724	8
9	Cost of Refinancing Debt				-808			-808	9
10	Property Taxes							0	10
11	FAS 106 & FAS 112 Post Retirements Benefits				-7,348			-7,348	11
12	Environmental Reserve				-666			-666	12
13	Regulatory Asset FAS 109							0	13
14						0			14
15	Total Deferred Income Taxes	838,957	0		-880,873	0	0	-41,916	15

NORTHWESTERN ENERGY - SOUTH BEAR PAW RATE BASE - 13 MONTH AVERAGE NORTHWESTERN ENERGY COMPANY

LINE	DESCRIPTION	(B) SOUTH BEAR PAW	(G) REGULATORY PLANT ADJ	NORMALIZING ADJUSTMENT	(I) DEFERRED TAXES	(J) OTHER	(K) WORKING CAPITAL	(L) TEST PERIOD 12/31/15 ADJUSTED	LINE
1	UTILITY PLANT IN SERVICE								1
2	Gas	61,756,259						61,756,259	2
3	Common	3,189,648						3,189,648	3
4	TOTAL UTILITY PLANT IN SERVICE	64,945,907	0					64,945,907	4
5									5
6	ACCUMULATED DEPRECIATION								6
7	Gas	7,498,904	0	-9,357				7,489,547	7
8	Common	1,256,207						1,256,207	8
9	TOTAL ACCUMULATED DEPRECIATION	8,755,111	0	-9,357				8,745,754	9
10									10
11	TOTAL NET PLANT	56,190,796	0	9,357				56,200,153	11
12									12
13									13
14	GAS STORED UNDERGROUND							0	14
15	COST OF REFINANCING DEBT							0	15
16	GAS STORAGE SALES 2000 & 2001 (9-2039)							0	16
17	REGULATORY ASSET FAS 109							0	17
18	MPSC/MCC TAXES							0	18
19									19
20									20
21	LESS: CUSTOMER CONTRIBUTED CAPITAL								21
22	Accumulated Deferred Income Taxes								22
23	See Page 2 for Details	2,649,536			196,714	0		2,846,250	23
24	Personal Injury & Property Damage							0	24
25	Customer Advances for Construction							0	25
26	TOTAL CUSTOMER CONTRIBUTED CAPITAL	2,649,536	0		196,714	0		2,846,250	26
27									27
28	PLUS: WORKING CAPITAL								28
29	Gress Cash Requirements						-1,717,534	-1,717,534	29
30	Materials and Supplies							0	30
31	TOTAL WORKING CAPITAL						-1,717,534	-1,717,534	31
32									32
33	TOTAL GAS UTILITY RATE BASE	53,541,260	0	9,357	-196,714	0	-1,717,534	51,636,370	33

1	Accumulated Deferred Income Taxes								1
2	Regulatory Liability - MPSC Taxes				-708			-708	2
3	Accelerated Depreciation	1,365,380			718,216			2,083,596	3
4	Customer Advances for Construction				-5,020			-5,020	4
5	Net Operating Loss	1,284,156			-445,235			838,922	5
6	Deferred Revenue				-56,041			-56,041	6
7	Accrued Incentive Compensation				-3,099			-3,099	7
8	Injuries & Damages				5,093			5,093	8
9	Cost of Refinancing Debt				-1,510			-1,510	9
10	Property Taxes							0	10
11	FAS 106 & FAS 112 Post Retirements Benefits				-13,737			-13,737	11
12	Environmental Reserve				-1,246			-1,246	12
13	Regulatory Asset FAS 109							0	13
14						0			14
15	Total Deferred Income Taxes	2,649,536	0		196,714	0	0	2,846,250	15

NORTHWESTERN ENERGY - CANADIAN MONTANA PIPELINE RATE BASE - 13 MONTH AVE NORTHWESTERN ENERGY COMPANY

LINE	DESCRIPTION	(B) CMPL	(G) REGULATORY PLANT ADJ	NORMALIZING ADJUSTMENT	(I) DEFERRED TAXES	(J) OTHER	(K) WORKING CAPITAL	(L) TEST PERIOD 12/31/15 ADJUSTED	LINE
1	UTILITY PLANT IN SERVICE								1
2	Gas	370,973						370,973	2
3	Common							0	3
4	TOTAL UTILITY PLANT IN SERVICE	370,973	0					370,973	4
5									5
6	ACCUMULATED DEPRECIATION								6
7	Gas	279,968	0	7,290				287,258	7
8	Common							0	8
9	TOTAL ACCUMULATED DEPRECIATION	279,968	0	7,290				287,258	9
10									10
11	TOTAL NET PLANT	91,005	0	-7,290				83,715	11
12									12
13									13
14	GAS STORED UNDERGROUND							0	14
15	COST OF REFINANCING DEBT							0	15
16	GAS STORAGE SALES 2000 & 2001 (9-2039)							0	16
17	REGULATORY ASSET FAS 109							0	17
18	MPSC/MCC TAXES							0	18
19									19
20									20
21	LESS: CUSTOMER CONTRIBUTED CAPITAL								21
22	Accumulated Deferred Income Taxes								22
23	See Page 2 for Details				0	0		0	23
24	Personal Injury & Property Damage							0	24
25	Customer Advances for Construction							0	25
26	TOTAL CUSTOMER CONTRIBUTED CAPITAL	0	0		0	0		0	26
27									27
28	PLUS: WORKING CAPITAL								28
29	Gross Cash Requirements						0	0	29
30	Materials and Supplies							0	30
31	TOTAL WORKING CAPITAL						0	0	31
32									32
33	TOTAL GAS UTILITY RATE BASE	91,005	0	-7,290	0	0	0	83,715	33

1	Accumulated Deferred Income Taxes								1
2	Regulatory Liability - MPSC Taxes							0	2
3	Accelerated Depreciation							0	3
4	Customer Advances for Construction							0	4
5	Net Operating Loss							0	5
6	Deferred Revenue							0	6
7	Accrued Incentive Compensation							0	7
8	Injuries & Damages							0	8
9	Cost of Refinancing Debt							0	9
10	Property Taxes							0	10
11	FAS 106 & FAS 112 Post Retirements Benefits							0	11
12	Environmental Reserve							0	12
13	Regulatory Asset FAS 109							0	13
14						0			14
15	Total Deferred Income Taxes	0	0		0	0	0	0	15

NorthWestern Energy
2015 UTILITY ADMINISTRATION STUDY including Hydro
September 2014

Plant Allocation (000's Omitted)

	In-Service	CWIP	Common Plant	Gross Plant	Percent
MTU	3,648,257	105,528	0	3,753,785	76.14%
NPS	799,812	80,303	0	880,116	17.85%
CU4	290,171	6,184		296,356	6.01%
Total	**4,738,241**	**19,805**	**0**	**4,930,256**	**100.00%**

Source: SAP Trial Balance Account 160000-165999 MT12-100, SD12-100

Margin

MTU	569,541	75.45%
NPS	113,901	15.09%
CU4	71,368	9.46%
Total	**754,810**	**100.0%**

Source: Historical Income by Segment (Profit Centers) MT01-100, SD01-100

Operating Labor Allocation (000's Omitted)

MTU	74,903	82.31%
NPS	16,099	17.69%
CU4	0	0.00%
Total	**91,002**	**100.00%**

Source: SAP Trial Balance Account 503000-503999

Allocation of Factors

Gross Plant:

	MTU	76.14%
	NPS	17.85%
	CU4	6.01%

Margin:

	MTU	75.45%
	NPS	15.09%
	CU4	9.46%

Direct Labor:

	MTU	82.31%
	NPS	17.69%
	CU4	0.00%

	Plant	Margin	Labor	Total	%
Total MTU	**76.14%**	**75.45%**	**82.31%**	**233.90%**	**78%**
Total NPS	**17.85%**	**15.09%**	**17.69%**	**50.63%**	**17%**
Total CU4	**6.01%**	**9.46%**	**0.00%**	**15.47%**	**5%**

2015 Blanket Order Settlement
Utility Admin & Other Shared

This schedule reflects the order settlement, and is derived from a combination of the Utility Admin 3-factor allocation and the A&G 3-factor allocation.

Utility Admin allocation = gross plant, margin, and labor
A&G allocation = plant, customers, and labor

Common Utility Admin Order Settlement		Util Admin MTU Jurisdiction	Electic 71% Split	Gas 29% Split
MT Electric	55.00%	78.00%	55.00%	23.00%
MT Gas	23.00%			
Colstrip Unit 4	5.00%			
SD Electric	10.00%			
SD Gas	4.00%			
NE Gas	3.00%			

Common Customer Care Order Settlement

MT Electric	58.00%
MT Gas	23.00%
SD Electric	11.00%
SD Gas	5.00%
NE Gas	3.00%

Common Utility Communications Order Settlement

MT Electric	58.00%
MT Gas	23.00%
SD Electric	11.00%
SD Gas	5.00%
NE Gas	3.00%

Montana Regulatory Affairs

MT Electric	71.20%
MT Gas	28.73%
MT Propane	0.07%

Common Montana Only

MT Electric	71.00%	Per the A&G Study
MT Gas	29.00%	

Common SD & NE Only

SD Electric	59.00%
SD Gas	24.00%
NE Gas	17.00%

Common South Dakota Only

SD Electric	70.00%
SD Gas	30.00%

Common SD & NE Gas Only

SD Gas	60.00%
NE Gas	40.00%

NorthWestern Energy-Montana
General Office Allocation
2015 A&G Allocation Study

Including Hydro

Plant Allocation (000's Omitted)

	In-Service	CWIP	Common Plant	Gross Plant	Percent
Electric	2,937,815	85,472	73,843	3,097,130	81.00%
Gas	687,819	20,011	17,289	725,119	18.96%
Propane	1,520	44		1,564	0.04%
Total	**3,627,154**	**105,528**	**91,132**	**3,823,813**	**100.00%**

Source: Plant in Service Account 161015 (Dan Reardon)/CWIP 165075 & 165185 MTU Balance Sheet
Common Plant Allocated based on Plant in Service - Including Hydro Plant $900,000,000

Customers

Electric	355,333	65.46%
Gas	186,949	34.44%
Propane	574	0.11%
Total	**542,856**	**100.00%**

Source: Business Warehouse Customers by Division/Electric & Gas Stat Reports

O&M Labor Expense

Electric	49,018,955	67.13%
Gas	23,948,215	32.80%
Propane	51,024	0.07%
Total	**73,018,193**	**100.00%**

Source: SAP 12 ME Labor - Including Hydro 2015 O&M Budget Labor

Allocation of Factors

Gross Plant:

Electric	81.00%
Gas	18.96%
Propane	0.04%

Customers:

Electric	65.46%
Gas	34.44%
Propane	0.11%

Direct Labor:

Electric	67.13%
Gas	32.80%
Propane	0.07%

Utility Allocation

Total Electric	**81.00%**	**65.46%**	**67.13%**	**213.58%**	**71.20%**
Total Gas	**18.96%**	**34.44%**	**32.80%**	**86.20%**	**28.73%**
Total Propane	**0.04%**	**0.11%**	**0.07%**	**0.22%**	**0.07%**

MEMORANDUM

TO: File

FROM: John Peters

DATE: October 27, 2014

RE: **2015 MONTANA ADMINISTRATIVE AND GENERAL ALLOCATION STUDY INCLUDING HYDRO BUDGET PLANT & LABOR**

The September 2014 period allocation study was completed October 27, 2014. The same criteria for both the General Office and Divisions was used as in prior studies. The results are:

General Office Electric & Gas Allocation Study (September 2014)

Factors used were:

1. Rate-Based Plant Balances (September 2014)
2. Customers (September 2014)
3. Operations Labor (12ME September 2014)

The results are:

Electric -	71%
Gas -	29%
Propane -	0%

Division Allocation Study (September 2014)

Factors used were:

1. Customers (by Division September 2014)
2. Distribution O&M (12ME September 2014)
3. Distribution Plant (by Division September 2014)

The results are:

	Electric	Gas
Billings & Lewistown.....	**91%**	**9%**
Bozeman & Livingston.....	**69%**	**31%**
Butte.....	**65%**	**35%**
Great Falls.....	**88%**	**12%**
Havre.....	**73%**	**27%**
Helena.....	**70%**	**30%**
Missoula & Hamilton.....	**65%**	**35%**
Kalispell.....	**0%**	**100%**

Common T&D (Segments) Allocation Study (September 2014)

Factors used were:

1. O&M Labor (12ME September 2014)

The results are:

	Common Electric	Common Gas	Common Electric & Gas
Electric Other Generation.....	6%		4%
Electric Hydro Generation.....	0%		0%
Electric Transmission.....	23%		16%
Electric Distribution.....	71%		51%
Subtotal-Electric.....	**100%**	**0%**	**71%**
Natural Gas Production.....		14%	4%
Natural Gas Storage.....		3%	1%
Natural Gas Transmission.....		31%	9%
Natural Gas Distribution.....		52%	15%
Subtotal-Natural Gas.....	**0%**	**100%**	**29%**

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF WAYNE M. HITT

ON BEHALF OF NORTHWESTERN ENERGY

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Property Tax Adjustment	10

Witness Information

Q. Please state your name and business address.

A. My name is Wayne M. Hitt. My business address is 3010 West 69th Street, Sioux Falls, South Dakota 57108.

Q. By whom are you employed and in what capacity?

A. I am employed by NorthWestern Energy ("NorthWestern") as Director-Corporate Taxes.

Q. Please describe your education and business experience.

A. I graduated from Southern Illinois University in 1980 with a Bachelor's degree in Business Administration with a major in Accounting. I am a Certified Public Accountant (inactive) in California and South Dakota. I have over 35 years of experience in the field of corporate taxation, of which over 30 years have been spent working with or for public utility companies. I have been Director–Corporate Taxes at NorthWestern since January 1, 2008. Before joining NorthWestern, I served NorthWestern as an independent consultant functioning as the Manager-Income Tax for approximately 4 1/2 years. Prior to my relationship with NorthWestern, I held various positions for Sempra Energy and its subsidiaries (including San Diego Gas & Electric Company and Southern California Gas Company) for a total of approximately 22 years, most recently serving as Director-Corporate Taxes from 2000 to 2003.

1 **Q. What are your responsibilities as Director-Corporate Taxes?**

2 **A.** I am responsible for all tax-related compliance, research and planning

3 activities for NorthWestern.

4

5 **Purpose of Testimony**

6 **Q. What is the purpose of your testimony?**

7 **A.** I support all income and property tax related items included in this filing. I

8 supervised and controlled the preparation of all income and property tax items

9 in the natural gas income statements and rate base exhibits.

10

11 **Q. Have income taxes in this filing been calculated in a manner consistent**

12 **with the methodology approved by the Montana Public Service**

13 **Commission ("Commission" or "MPSC") in prior rate proceedings?**

14 **A.** Yes. NorthWestern calculated income using the partial flow-through method

15 that the Commission has consistently approved in prior dockets.

16 NorthWestern has always flowed plant-related tax adjustments through to

17 customers, except for those subject to mandatory normalization under

18 Section 168 of the Internal Revenue Code ("IRC").

19

20 With regard to tax-deductible repairs, on September 25, 2009, NorthWestern

21 received a Consent Letter from the Internal Revenue Service ("IRS")

22 responding to NorthWestern's request to change its method of accounting for

23 deductible repair expenses for income taxes for tax years 2008 and later.

1 The IRS permits NorthWestern to recognize a significant portion of repair
2 expenditures as ordinary and necessary business expenses deductible for
3 income tax purposes in the year they are incurred. As these expenses are
4 not subject to mandatory normalization, NorthWestern flowed them through to
5 customers in this filing.
6
7 Bonus tax depreciation, originally authorized pursuant to the Tax Relief,
8 Unemployment Insurance Reauthorization, and Jobs Creation Act of 2010,
9 was extended through December 31, 2019 by the Protecting Americans from
10 Tax Hikes (PATH) Act of 2015. NorthWestern flows the Montana income tax
11 benefit of bonus depreciation through for the benefit of retail customers in this
12 filing. However, because bonus depreciation is subject to mandatory
13 normalization, NorthWestern reduces rate base, which benefits retail
14 customers. The tax law allows 50% bonus tax depreciation through 2017,
15 40% in 2018, 30% in 2019, and none after 2019. Under the transition rules
16 for large self-constructed assets, in certain conditions bonus depreciation will
17 apply beyond December 31, 2019.
18
19 **Deferred Income Taxes for Natural Gas Transmission,**
20 **Distribution, Storage, and Production**
21 **Q. Please explain all of the provisions for deferred income taxes.**
22 **A.** The Statement J Workpapers show the detail of the deferred income taxes for
23 the Natural Gas Transmission, Distribution, Storage, and Production Utility

2015 test period revenue requirement. Below, I discuss the deferrals shown in that statement.

Injuries and Damages

For book purposes, NorthWestern accrues expenses for personal injuries and damages for based on actuarial studies. For income tax purposes, NorthWestern deducts these expenses when paid. In the test year, NorthWestern accrued $97,991 less than it paid. NorthWestern recognized an increase to deferred income taxes of $38,596 to account for the temporary difference and reduced rate base by the same amount.

Environmental Reserve

For book purposes, NorthWestern accrues expenses for environmental costs based upon estimated costs of future environmental remediation. For income tax purposes, NorthWestern deducts these expenses when paid. In the test year, NorthWestern accrued $70,498 less than it paid. NorthWestern recognized an increase to deferred income taxes of $27,768 to account for the temporary difference and reduced rate base by the same amount.

Accrued Incentive Compensation

NorthWestern uses incentive pay plans for all employees as part of their compensation package. NorthWestern accrues incentive pay during the current year but pays it in March of the following year. For income tax

purposes, NorthWestern deducts these expenses when paid. In the test year, NorthWestern accrued $453,850 less than it paid. NorthWestern recognized an increase to deferred income taxes of $178,759 to account for the temporary difference and reduced rate base by the same amount.

Accelerated Depreciation

For federal income tax purposes, NorthWestern uses accelerated tax depreciation including bonus tax depreciation as described above. For calculating deferred income taxes, NorthWestern uses normalized tax depreciation computed using book lives and book methods applied to the tax basis of assets. The IRC and IRS regulations require that NorthWestern calculate deferred taxes this way to remain qualified to use accelerated methods of tax depreciation on its federal tax return. In the test year for natural gas assets, NorthWestern's tax depreciation exceeded its normalized tax depreciation by $12,015,534 which caused an increase in deferred federal income taxes of $4,205,438 and a decrease of rate base of the same amount.

NOL Deferred Tax Asset

A net operating loss ("NOL") results if tax deductions exceed taxable income in a given year. An NOL Deferred Tax Asset represents the amount of tax benefit from stand-alone utility tax losses (i.e., NOL) that have been deferred as an NOL tax receivable from the taxing authorities. When NorthWestern incurs future current tax liabilities, it will use this NOL tax receivable to pay

them. In the test year, NorthWestern utilized NOL carry forward of $8,810,839. NorthWestern recognized an increase to deferred income taxes of $3,470,369 and reduced rate base by the same amount.

Customer Advances for Construction and Contributions In Aid of Construction

When NorthWestern collects a Contribution in Aid of Construction ("CIAC") or a Customer Advance for Construction ("CAC"), the books reduce capitalized plant costs by the amount collected. For income tax purposes, the amount collected is taxable income to NorthWestern and the tax basis of the capitalized plan costs is increased for tax depreciation purposes. In Order No. 5236c in Docket No. 86.11.62, the Commission determined that the cost causer, not the general body of ratepayers, should bear the costs associated with the taxability of CIAC and CAC. To recover the costs associated with the current tax liability related to receipt of CIAC and CAC, which is subsequently recovered through tax depreciation deductions in future years, NorthWestern is allowed to collect a surcharge from the party requesting the extension of service facilities. The surcharge reduces rate base and book depreciation charged to customers. The deferred taxes related to CIAC and CAC serve to offset the current taxes related to CIAC and CAC to ensure that customers are not charged for amounts for which they are not responsible. In the test year, NorthWestern recognized CIAC and CAC taxable income of $1,135,513. NorthWestern recognized a decrease to deferred income taxes

of $447,251 and increased rate base by the same amount.

Financial Accounting Standards (FAS) 106 and 112 Post Retirement Benefits

NorthWestern accounts for post-retirement and post-employment healthcare and pension benefits under the accrual method. For income tax purposes, these expenses are deducted as paid. In the test year, NorthWestern accrued $1,943,395 less than it paid. NorthWestern recognized a decrease to deferred income taxes of $765,455 to account for the temporary difference and increased rate base by the same amount.

Costs of Refinancing Debt

NorthWestern accounts for costs related to the refinancing of its old debt by amortizing those costs over the term of the new debt. For income tax purposes, these costs are deducted in the year incurred. In the test year, NorthWestern amortized $57,587 more than it incurred. NorthWestern recognized a decrease to deferred income taxes of $22,682 to account for the temporary difference and increased rate base by the same amount.

Deferred Revenue

NorthWestern defers for book purposes certain revenues related to transmission reservations or access feasibility studies, etc. For income tax purposes, these revenues are recognized when they are received. In the test

year, NorthWestern received $2,201,740 of deferred revenue. NorthWestern recognized a decrease to deferred income taxes of $867,210 to account for the temporary difference and increased rate base by the same amount.

MPSC/Montana Consumer Counsel ("MCC") Taxes

NorthWestern defers for book purposes differences between MPSC/MCC taxes collected in revenue versus the amount of MPSC/MCC taxes paid. For income tax purposes, these revenues are recognized as taxable income when they are received, and these taxes are deducted when paid. In the test year, NorthWestern accrued $79,632 more than it paid. NorthWestern recognized a decrease to deferred income taxes of $31,365 to account for the temporary difference and increased rate base by the same amount.

Natural Gas – Computation of Current Income Taxes

Q. Please explain Income Taxes – Federal – US and Income Taxes – Other shown on the 2015 test period exhibits attached to the Prefiled Direct Testimony of Patrick J. DiFronzo ("DiFronzo Direct Testimony").

A. In regard to the Natural Gas Transmission, Distribution, Storage Utility and the individual Gas Production Asset 2015 test period revenue requirements, the computations of the Federal Income, Canadian Income and Montana Corporation License Taxes including explanation of the adjustments necessary to determine the test period taxes are shown on Statement J, Workpapers B.

1 **Q. Are Income Taxes – Federal – US and Income Taxes – Other shown on**
2 **historical and forecast exhibits related to the natural gas production**
3 **assets attached to the DiFronzo Direct Testimony calculated in a similar**
4 **fashion?**
5 **A.** Yes.
6
7 **Property Tax Adjustment**
8 **Q. Please explain the property tax adjustment included on page 2, Column**
9 **M Taxes – Other Than Income Adjustment, of Exhibit__(PJD-11) of the**
10 **DiFronzo Direct Testimony.**
11 **A.** The 2015 actual property taxes included in this natural gas filing have been
12 adjusted to include 2015 net plant additions. Actual cost to market factors for
13 2016 were used to arrive at appraised values for the various classes of
14 property. Estimated mill levies were used to calculate tax expense. The mill
15 levies will be adjusted at the time NorthWestern files its rebuttal testimony in
16 this proceeding to reflect changes that will be known at that time, which is
17 consistent with prior Commission practice. Statement K summarizes the
18 Natural Gas Transmission, Distribution, Storage, and Production Utility 2015
19 test period property taxes included in this filing.
20
21 **Q. Does this complete your testimony?**
22 **A.** Yes, it does.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF JOHN S. CANAVAN

ON BEHALF OF NORTHWESTERN ENERGY

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Exhibits

On System General Terms and Operating Conditions (Natural Gas Tariff Schedule No. GTC-1) – Redline	Exhibit__(JSC-1)
On System General Terms and Operating Conditions (Natural Gas Tariff Schedule No. GTC-1) – Clean	Exhibit__(JSC-2)
Aggregation General Terms and Operating Conditions (Natural Gas Tariff Schedule No. AGTC-1) – Redline	Exhibit__(JSC-3)
Aggregation General Terms and Operating Conditions (Natural Gas Tariff Schedule No. AGTC-1) – Clean	Exhibit__(JSC-4)

Witness Information

Q. Please state your name and business address.

A. My name is John Canavan. My business address is 11 East Park Street, Butte, Montana 59701.

Q. By whom are you employed and in what capacity?

A. I am employed by NorthWestern Energy ("NorthWestern") as Manager, Gas Transmission Services.

Q. Please summarize your education and employment experience.

A. I earned a Bachelor of Science degree in Business Management in 1982 from Montana State University ("MSU"). I also earned Minor degrees in Industrial and Management Engineering and in Accounting from MSU and an Associate of Science degree (emphasis in Computer Science) from Montana Tech. I am a non-practicing Certified Fraud Examiner, a non-practicing Certified Internal Auditor, and a non-practicing Certified Information Systems Auditor, as well as a Certified North American Electric Reliability Corporation Electric System Operator.

I attended the Public Utilities Executive Course at the University of Idaho and the Executive Communications Course at the University of Michigan Business School.

1 I began my professional career with NorthWestern's predecessor, the
2 Montana Power Company ("MPC"), in April 1982 as an Internal Auditor
3 and have been employed by MPC and NorthWestern ever since. During
4 my career I have held a variety of management level positions; in May
5 2014 I assumed my current position.
6
7 **Q. What are your responsibilities as Manager, Gas Transmission**
8 **Services?**
9 **A.** I have overall responsibility for NorthWestern's natural gas utility's gas
10 transportation services. This includes negotiating, developing, and
11 administering gas storage and transportation contracts and services;
12 participating in the preparation and presentation of natural gas utility rate
13 cases and budget processes; interacting with non-core customers and
14 interconnecting pipelines; and working very closely with engineering,
15 operational, and regulatory personnel. In conjunction with Gas Operations
16 personnel, I develop contract terms and products that best utilize the gas
17 transmission and storage systems. I also work very closely with Gas
18 Operations personnel to ensure there is enough natural gas nominated on
19 NorthWestern's system to serve the required loads, particularly during
20 Critical Operating Times.
21
22 Additionally, I oversee the daily, monthly, and yearly processes related to
23 the scheduling of gas on NorthWestern's natural gas transportation

system, balancing the receipts and deliveries of this gas, fulfilling regulatory reporting requirements, and preparing the information needed to produce the monthly billing, all in accordance with applicable tariff terms and conditions.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support and explain NorthWestern's proposed changes to the On System General Terms and Operating Conditions included in Natural Gas Tariff Schedule No. GTC-1 and to the Aggregation General Terms and Operating Conditions included in Natural Gas Tariff Schedule No. AGTC-1.

Proposed Tariff Changes

Q. Why is NorthWestern proposing changes to the General Terms and Operating Conditions ("GTCs") and what types of changes are being proposed?

A. The passage of time necessitates changes to the GTCs to reflect actual current conditions and practices.

Many of the proposed changes to the GTCs are to remove language related to practices that were never performed or are no longer performed due to lack of interest on the part of NorthWestern's customers, or to

reflect modifications in NorthWestern's business operations. Language is also modified to reflect actual practice or for administrative efficiency. Other changes are necessary to add clarifying text and to correct grammar, references, and other minor errors.

Q. Have you provided revised versions of Natural Gas Tariff Schedule No. GTC-1 and Natural Gas Tariff Schedule No. AGTC-1 that include all proposed changes to On System and Aggregation GTCs?

A. Yes. Exhibits__(JSC-1) and (JSC-2) are redlined and clean versions of Natural Gas Tariff Schedule No. GTC-1. Exhibits__(JSC-3) and (JSC-4) are redlined and clean versions of Natural Gas Tariff Schedule No. AGTC-1. All proposed changes are shown on the redlined versions; the clean versions include them all as well.

Q. Please describe changes made to remove language related to practices that were never or are no longer performed due to lack of interest on the part of NorthWestern's customers or changes in business operations, as well as changes made to modify language to reflect actual practice.

A. Changes were made to the Standards of Conduct Section in both of the GTCs (Section 21 of the On System GTCs and Section 19 of the Aggregation GTCs) because NorthWestern has not had a Marketing Affiliate for many years. Also, the Creditworthiness provisions in both of

1 the GTCs (Section 18.6 of the On System GTCs and Section 20.2 of the
2 Aggregation GTCs) were changed to reflect current credit-related
3 practices, which are more robust than the original procedures.
4
5 The provision in Section 15.2 of both GTCs allowing Shippers to trade
6 imbalances was eliminated because there has never been a case in which
7 Shippers wanted to utilize this option. Also, the Cash Out provisions in
8 this section of both GTCs were updated to reflect current practices and
9 gas pricing sources. Section 20.2 of the On System GTCs was modified
10 to reflect the current practice for assessing Maximum Daily Delivery
11 Quantities ("MDDQs") for distribution level customers. The current
12 practice is an "after the fact" review and comparison of customers'
13 MDDQs to recent peak day loads rather than a "before the fact" prediction
14 of what the MDDQs should be. NorthWestern believes this approach is
15 more accurate and fair for its customers because of the difficulty in
16 predicting the future, particularly the weather.
17
18 **Q. Please describe changes made for administrative efficiency.**
19 **A.** Section 17.7 of the Aggregation GTCs was modified to add requirements
20 regarding when customers can switch between Core Aggregation and
21 Core Sales service to prevent unnecessary administrative burden. The
22 process takes about 45 days to activate a customer on either service. For
23 example, a Core Sales customer who wants to switch to Core Aggregation

1 service must complete a Core Aggregation enrollment form. Once this
2 form is completed, the customer is assigned a customer ID and the Core
3 Aggregation customer data base is updated with the information from the
4 enrollment form. Once the customer is established as a Core Aggregation
5 customer, it is necessary to ensure enough gas is nominated to cover the
6 customer's load for the time the customer remains a Core Aggregation
7 customer. The customer must also be terminated from Core Sales
8 service, including sending out a final Core Sales service bill. The process
9 is basically the same for Core Aggregation customers who switch to Core
10 Sales service.
11
12 Under the current tariff language, customers can change services at any
13 time during the month. For example, the customer could be on Core
14 Sales service for half of the month and Core Aggregation service for the
15 other half, or 10 days on one service and 20 days on the other. We have
16 had customers enroll in the Core Aggregation program and before they
17 complete the process for becoming Core Aggregation customers they
18 cancel or terminate service and want to go back to Core Sales. All of this
19 described activity has to be carefully tracked to make sure all transactions
20 are properly accounted for, and the more frequently customers are
21 allowed to transition between services, the more confusing and error
22 prone the process becomes. As part of our research before proposing this
23 change, NorthWestern reviewed other Core Aggregation tariffs, and every

tariff we reviewed requires customers to stay on one service or the other for at least a year before being able to switch services.

Q. Please describe changes made to tariff language to add clarifying text.

A. Section 18.3 of the On System GTCs was modified to provide clarification regarding when Shippers are required to increase their transmission MDDQs. This clarification was needed because some Shippers have misinterpreted the intent of this provision, resulting in the potential for MDDQs not being accurately increased on a timely basis.

Changes to Section 18.7 of the On System GTCs

Q. Please explain the deletions made in Section 18.7 of the On System GTCs.

A. The section describing third party storage facilities was deleted because NorthWestern does not have third party storage on its system.

Q. Please explain the additions NorthWestern is proposing to Section 18.7 of the On System GTCs.

A. A new section that addresses short-term and long-term planning has been added. Regarding short-term planning, before each heating season it is NorthWestern's established practice to request that each Shipper provide an accounting of its winter peak loads and associated supplies. This is

1 necessary to ensure each Shipper will have enough firm gas supply and
2 transport capacity to cover its peak loads during a Critical Operating Time.
3 This very important practice designed to help ensure system reliability has
4 not been documented in the GTCs, and NorthWestern is proposing that
5 this practice now be included as part of the tariff.
6
7 Regarding long-term planning, the Prefiled Direct Testimony of Michael R.
8 Cashell ("Cashell Direct Testimony") addresses the challenges that
9 NorthWestern faces in expanding its Gas Transmission System in order to
10 meet growing demand. In an effort to begin the long-term planning
11 necessary to meet the challenges identified in the Cashell Direct
12 Testimony, NorthWestern proposes to implement a regular formal long-
13 term planning process. This process will be conducted every two years
14 and will involve core and non-core customers and their representatives
15 and any other appropriate stakeholders. The process will gather
16 information regarding 10-year load projections and the supply and pipeline
17 resources that customers/marketers anticipate utilizing to supply those
18 loads. NorthWestern will then develop plans based on this information,
19 communicate its plans to stakeholders, and implement them as
20 appropriate. NorthWestern anticipates that the first cycle of this process
21 will be a learning opportunity and fully expects that the process will be
22 improved over time. At the request of the Commission, NorthWestern will

1 provide status updates, including lessons learned, process improvements,

2 study results, etc.

3

4 **Q. Does this conclude your testimony?**

5 **A.** Yes it does.

NATURAL GAS TARIFF

NorthWestern Energy

	Original	Revised	Sheet No.	95.1
Canceling		Revised	Sheet No.	95.1

Schedule No. GTC-1

ON SYSTEM
GENERAL TERMS AND OPERATING CONDITIONS

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(continued)

Schedule No. GTC-1

ON SYSTEM
GENERAL TERMS AND OPERATING CONDITIONS

1. DEFINITIONS: The following terms and abbreviations, when used in these General Terms and Operating Conditions (Rate Schedule No. GTC-1), the Rate Schedules, and the Service Agreements (Agreements), shall have the following meaning:

1.1 "BTU" shall mean British Thermal Unit.

1.2 "Cubic foot of gas" shall mean that quantity of gas which, at a temperature of 60° Fahrenheit and at pressure of 14.9 pounds per square inch absolute, occupies 1 cubic foot.

1.3 "Day" shall mean a period of 24 consecutive hours, beginning and ending at 8:00 a.m. Mountain Time.

1.4 "Dekatherm" shall mean 1,000,000 BTUs.

1.5 "Gas" shall mean natural gas of the quality specified in Section 2 hereof.

1.6 "Gross heating value" shall mean the number of BTUs in a cubic foot of gas as calculated from a gas analysis obtained by gas chromatography. The heating value shall be calculated by summation of the heating values determined by GPA standard 2145. The heating value shall be calculated on a dry basis at a temperature of 60 degrees Fahrenheit and a pressure of 14.9 pounds per square inch absolute.

1.7 "Large Variable Load Shipper" shall mean any Shipper with firm daily consumption over 5,000 dekatherms and with the ability to increase hourly flows at a rate greater than 200 dekatherms per hour.

1.8 "Maximum Daily Delivery Quantity (MDDQ)" shall mean the maximum quantity of gas, after adjustments for compressor station fuel and line losses and other unaccounted for gas, if applicable, which Utility shall deliver to Shipper, or for Shipper's account, at the Point(s) of Delivery on any day.

1.9 "Maximum Daily Receipt Quantity (MDRQ)" shall be the MDDQ that Utility has contracted to receive at the Point(s) of Receipt on behalf of Shipper, including the compressor station fuel, line losses and other unaccounted for gas for any particular day.

1.10 "MCF" shall mean 1,000 cubic feet of gas and shall be measured as set forth in Section 4 hereof.

(continued)

Schedule No. GTC-1

ON SYSTEM
GENERAL TERMS AND OPERATING CONDITIONS

~~1.11~~ 1.11 "Month" shall mean a period extending from the beginning of the first day in a calendar month to the beginning of the first day in the next succeeding calendar month.

1.12 "Point(s) of Delivery" shall mean point(s) where Utility delivers gas for the account of Shipper.

1.13 "Point(s) of Receipt" shall mean point(s) where Utility receives gas for the account of Shipper.

1.14 "Primary Point(s) of Receipt" shall mean those point(s) designated as Primary in the Firm Gas Transmission Service Agreement where Shipper is entitled to firm service.

1.15 "Psia" shall mean pounds per square inch absolute.

1.16 "Psig" shall mean pounds per square inch gauge.

1.17 "Secondary Point(s) of Receipt" shall mean points other than Primary Point(s) of Receipt where Utility receives gas for the account of Shipper for transportation under a Firm Gas Transmission Service Agreement.

1.18 "Service Date" shall mean the date Utility receives a formal written request for transportation and/or storage service from Shipper.

1.19 "Shipper" shall mean the party on whose behalf Utility provides transportation or storage service.

~~1.20~~1.18 ~~"Utility" shall mean NorthWestern Energy Transportation Business Unit (TBU).~~

~~1.21~~1.20 "Therm" - The word "Therm" as used herein shall mean 100,000 Btus. 10 therms is equivalent to one dekatherm.

1.21 "Used and Unaccounted For" (U&UAF) shall mean volumes associated with standard operating procedures in the delivery of gas.

1.22 "Utility" shall mean NorthWestern Energy Transportation Business Unit (TBU).

QUALITY OF GAS:

2.1 General Standards: Gas delivered to Utility shall be merchantable natural gas, at all times complying with the following quality requirements:

(continued)

Schedule No. GTC-1

ON SYSTEM
GENERAL TERMS AND OPERATING CONDITIONS

A. Gas shall be in its natural state as produced, including all hydrocarbon constituents therein contained except liquid or liquefiable hydrocarbons removed by Shipper. Shipper shall also have the right to remove nonhydrocarbon constituents. Shipper may enrich the gas to the extent required to meet the gross heating requirement set forth in paragraph "B" below, and may subject the gas, or permit the gas to be subjected, to compression, cooling, cleaning, dehydration and other processes. If Shipper is transferring gas to ~~the~~ Utility transmission line directly, provisions must be made by ~~the~~ Shipper to odorize the gas to the requirements set forth in the Department of Transportation publication CFR Title 49 Part 192.625.

~~A.~~B. The gross heating value of gas delivered to Utility shall not be less than 900 BTUs per cubic foot, and shall not be more than 1,200 BTUs per cubic foot. Utility may reject receipt of gas having a gross heating value of less than 900 BTUs per cubic foot or more than 1,200 BTUs per cubic foot. Acceptance of gas not meeting this gross heating value requirement shall not constitute a waiver of Utility's right to reject receipt of nonconforming gas.

C. Gas shall be merchantable and usable by the ultimate consumers without further treatment. In particular, the gas received by Utility hereunder at the Point(s) of Receipt shall be commercially free of dust, gum, gum-forming constituents, gasoline, other objectionable substances, and other solid or liquid matter that may become separated from the gas during transportation or storage and shall conform to the following specifications:

1.	Dust, rust or other solids	None
2.	Carbon dioxide	Not more than 2% by volume
3.	Oxygen	Not more than 10 parts per million or .001% by volume
4.	Hydrogen sulfide	Not more than 1/4 grain per 100 cubic feet
5.	Total sulfur	Not more than 2.0 grains per 100 cubic feet
6.	Temperature	Not more than 120° Fahrenheit.
7.	Water vapor	Not more than 4 pounds of water vapor per 1,000,000 cubic feet of gas
8.	Hydrocarbons	None liquefiable at temperatures in excess of 15(Fahrenheit at pressures up to 1,200 psig.

(continued)

Schedule No. GTC-1

ON SYSTEM
GENERAL TERMS AND OPERATING CONDITIONS

9. Nitrogen Not more than 15% by volume

D. Unless otherwise agreed, Utility shall not be required to receive at any Point of Receipt gas that is of a quality inferior to that required by a third party at any Point of Delivery.

2.2 Utility's Option to Treat: Utility, at its option, may refuse to accept delivery of any gas not meeting the quality specifications set out in this Section. Thereafter, Shipper shall have the right to conform the gas to the above specification. If Shipper does not elect to conform the gas to the specifications, then Utility may, at its option, accept gas tendered by Shipper which does not meet the specifications above, treat the gas to conform it to the specifications and charge Shipper for the actual cost of such treating, including, but not limited to, capital costs, O&M, fuel and shrinkage. Any Shipper tendering ~~nonspecification~~non specification gas shall indemnify ~~the~~ Utility for any injury, damage, loss or liability caused by the delivery of such gas, except to the extent Utility knowingly and willingly accepts such ~~nonspecification~~non specification gas.

2.3 Hydrogen Sulfide: At Utility's sole discretion, Utility may install, at Shipper's expense, a properly operating hydrogen sulfide monitoring device (H2S monitor) that is capable of curtailing any deliveries to ~~the~~ Utility of gas containing hydrogen sulfide in excess of 1/4 grain per 100 cubic feet (4 ppm).

3. PRESSURE:

3.1 Pressure at the Point(s) of Receipt: Shipper shall cause the gas to be tendered at the Point(s) of Receipt at a pressure sufficient to enter ~~the~~ Utility's system, provided Shipper shall not, except with the agreement ~~of the~~ Utility, be permitted to tender the gas at any Point of Receipt at a pressure in excess of the pressure specified for that Point of Receipt as set forth in the Agreement. If Shipper can supply gas at a higher pressure than the design of the pipeline system, Utility shall install, as a part of the equipment required under Section 4.3 below, pressure limiting devices to ensure the maximum allowable operating pressure (MAOP) of the pipeline shall not be exceeded.

3.2 Pressure at the Point(s) of Delivery: Utility shall cause the gas to be delivered at the Point(s) of Delivery at such pressures sufficient to effect delivery into the receiving facilities against the pressures prevailing from time-to-time.

4. MEASUREMENT AND TESTS:

4.1 Unit of Volume: The unit of volume for all gas measured hereunder shall be 1 cubic foot of gas.

4.2 Billing Unit: The billing unit of the gas transported or stored hereunder shall be one Therm.

(continued)

Schedule No. GTC-1

ON SYSTEM
GENERAL TERMS AND OPERATING CONDITIONS

4.3 Ownership of Measuring Equipment: All necessary measuring devices and materials will be furnished, installed, owned, operated and maintained by ~~the~~ Utility. Shipper may install and operate check measuring equipment provided it does not interfere with the use of ~~the~~ Utility's equipment in determining the volumes of gas being measured.

~~The~~ Utility shall have the option to install additional facilities that are required to provide service. Shipper shall pay, in addition to the rate(s) stated in the applicable Rate Schedule, at ~~the~~ Utility's option, the cost of the additional facilities.

If required by Utility for electronic metering, Shipper assumes responsibility for the installation and maintenance costs for a communication line necessary for electronic metering of gas quantities transported.

4.4 Metering and Computation of Volumes: The gas shall be metered by orifice meter, turbine meter, positive displacement meter or combination of meter types in a measurement facility constructed, installed and maintained by ~~the~~ Utility at or near the Point(s) of Receipt or Point(s) of Delivery. Such measurement facilities shall be constructed and installed in accordance with the most current provision for the meter type in the applicable American Gas Association Report. The volumes of gas received by or delivered to ~~the~~ Utility shall be the volumes received directly from the online measurement device. Such volumes shall be calculated, and corrected volumes from the online measurement device or computed from the meter records will be converted into the units of measurement specified herein in accordance with the methods prescribed by the currently adopted American Gas Association Report for the meter type. Corrections shall be made for gas volume deviation from the Ideal Gas Laws at the pressure and temperature at which the gas is metered. To determine the factors for such correction, a quantitative analysis of the gas shall be made at reasonable intervals with such apparatus as shall be agreed upon by ~~the~~ Utility and Shipper, and such factors shall be obtained from data contained in "Manual for the Determination of Supercompressibility Factors for Natural Gas" published by the American Gas Association as report "PAR Research Project NX-19" dated 1962 or "Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases" published by the American Gas Association as "Transmission Measurement Committee Report No. 8" dated November 1992, or any subsequent revision acceptable to ~~the~~ Utility and Shipper. For the purpose of measurement and meter calibration in the case of electronic measurement utilizing absolute pressure transducers, the actual atmosphere pressure shall be measured and used during calibration. Otherwise, the average atmospheric pressure will be used for gauge pressure transducers. A barometer or electronic barometer calibrated to a standard shall be used to determine the current atmospheric pressure.

(continued)

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ON SYSTEM
GENERAL TERMS AND OPERATING CONDITIONS

4.5 Specific Gravity: Tests to determine the specific gravity of the gas being metered shall be performed at reasonable intervals. The gas samples to be tested shall be representative of the gas delivered at the Point(s) of Delivery or Receipt. All such determinations of specific gravity shall be made by using gas chromatography and then calculating the specific gravity of the natural gas. The specific gravity of the gas flowing through each meter determined by the above-mentioned method shall be used in computing the volume of gas delivered through such meter. The specific gravity determined by any test shall apply from the date the test was taken until the date of the next year.

4.6 Temperature: The temperature of the gas delivered at the Point(s) of Receipt or Delivery hereunder, if required, shall be determined by means of standard electronic temperature devices or a recording temperature chart. The arithmetic average of readings recorded during each chart period shall be used in computing the volumes delivered hereunder.

4.7 Equipment Testing: The accuracy of ~~the~~ Utility's electronic measuring equipment shall be verified by test, using means and methods generally acceptable in the gas industry, at least annually or otherwise as agreed to by ~~the~~ Utility and Shipper. Shipper shall have the right to witness and verify all tests ~~of the~~ Utility's measuring equipment. Notice of the time and nature of each test shall be given to Shipper by ~~the~~ Utility sufficiently in advance to permit convenient arrangement for the presence of a representative of Shipper. Measuring equipment found to be registering inaccurately shall be adjusted to read as accurately as possible. If Shipper fails to witness any test, the results of the test shall nevertheless be considered accurate until the next test. All tests of such measuring equipment shall be made at ~~the~~ Utility's expense, except that Shipper shall bear the expense of tests made at its request if the inaccuracy is found to produce an error of 2% or less in the measurement of gas. ~~The~~ Utility will conduct all tests on all equipment operated by ~~the~~ Utility.

4.8 Measuring Equipment Out of Repair: If, for any reason, any measuring equipment is inoperative or inaccurate so that the volume of gas measured is not correctly indicated by the reading thereof, and if such reading is in error by more than 2% in the measurement of gas, then the volume of gas measured, during the period such measuring equipment is inoperative or inaccurate, shall be determined by the parties hereto on the basis of the best data available using the first of the following methods which is feasible.

A. By using the registration of any check measuring equipment installed and accurately registering;

(continued)

Schedule No. GTC-1

ON SYSTEM
GENERAL TERMS AND OPERATING CONDITIONS

B. By correcting the error if the percentage of error is ascertainable by calibration, test or mathematical calculations: or

C. By comparing measurements made during preceding periods under similar flow conditions when the meter was registering accurately.

An adjustment based on such determination shall be made for such period of inaccuracy as may be definitely known, or if not known, then for one-half the period since the date of the last meter test.

4.9 Gross Heating Value: The gross heating value per cubic foot of gas shall be determined from time-_to-_time by ~~the~~ Utility at ~~the~~ Utility's expense, using an accurately calibrated chromatograph, from samples of the gas taken at the Point(s) of Receipt or Delivery. ~~The~~ Shipper shall have the right to witness any and all tests of gross heating value made by ~~the~~ Utility. ~~The~~ Shipper shall have the right at any time to make or to require ~~the~~ Utility to make a special test of the gross heating value of gas delivered hereunder, but ~~the~~ Shipper shall bear the expense of any special tests made at its request.

5. INSPECTION OF EQUIPMENT AND RECORDS:

Each party shall have the right to inspect equipment installed or furnished by the other, and the charts and other measurement or test data of the other, at all times during business hours~~;~~, but the reading, testing, calibration and adjustment of such equipment and changing of charts shall be done only by the party installing or furnishing same. Unless the parties otherwise agree, each party shall preserve all original test data, charts and other similar records in such party's possession, for a period of at least 6 years.

6. BILLING:

6.1 Billing Under Gas Service Rate Schedules: On or before the twentieth (20th) day of each month, ~~the~~ Utility shall render a bill to Shipper under the applicable Rate Schedule(s) for the service rendered during the preceding month.

6.2 Statement by Shipper: When information necessary for billing by ~~the~~ Utility is in the control of ~~the~~ Shipper, Shipper shall furnish such information, estimated if actual is not available, ~~to the~~ Utility on or before the 3rd business day of the month following the month service was rendered. If Shipper furnishes estimated information, the actual information shall be furnished to ~~the~~ Utility on or before the 6th working day of the month following the month service was rendered.

(continued)

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ON SYSTEM
GENERAL TERMS AND OPERATING CONDITIONS

7. PAYMENT:

7.1 Adjustment of Billing Error: In the event that an error is discovered in any bill rendered by ~~the~~ Utility, the amount of such error shall be adjusted, provided that claim therefore shall have been made within 12 months from the date such bill was rendered. Any claim over 12 months old will not be allowed. The adjustment by either ~~the~~ Utility or ~~the~~ Shipper shall be made within 30 days of such timely claim.

8. NOTICE OF CHANGES IN OPERATING CONDITIONS:

~~The~~ Utility and Shipper shall assure that each other shall be notified from time-_to-_time, as necessary, of expected changes in the rates of delivery or receipt of gas, or in the pressures or other operating conditions, as stipulated to in the Agreement, and the reason for such expected changes, so that they may be accommodated when they occur. Quantities will be delivered at a uniform hourly rate of confirmed nominated quantity divided by 24, unless as determined by Utility, variance from the uniform hourly rate will not be detrimental to the operation of the pipeline or adversely affect other ~~Shipper's~~Shippers or Customers.

9. FORCE MAJEURE:

9.1 Notice: A party's obligation to perform shall be suspended in whole or in part: (1) if an event of force majeure occurs; and (2) the affected party provides written notice describing the event to the other as soon as reasonably possible after the event occurs. The affected party shall resume performance when conditions reasonably allow. The affected party shall not be required to make-up performance lost during the force majeure event.

9.2 Definition: The term "force majeure" shall mean acts of god, governmental action, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, hurricanes, tornadoes, storms, storm warnings, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accidents to machinery or lines of pipe, the necessity for making repairs to or alterations of machinery or lines of pipe, freezing of wells or lines of pipe, partial or entire failure of wells or sources of supply of gas, and any other causes, whether of the kind enumerated or otherwise, not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome. This term shall also include: (a) those instances where either party hereto is required to obtain servitudes, rights-of-way grants, permits or licenses to enable such party to fulfill its obligations, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such servitudes, rights-of-way grants, permits or licenses; and (b) those instances where either party hereto is required to furnish materials and supplies for the

(continued)

purpose of constructing or maintaining facilities or is required to secure permits or permissions from any governmental agency to enable such party to fulfill its obligations hereunder, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such materials and supplies, permits and permissions.

9.2 Strikes: The settlement of strikes or lockouts shall be within the discretion of the party having the difficulty, and that the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of any opposing party when such course is inadvisable in the discretion of the party having the difficulty.

10. WARRANTIES:

10.1 Eligibility:

A. Any Shipper transporting or storing gas on Utility's system warrants for itself, its successors and assigns~~,~~ that all gas delivered to Utility for service shall be eligible for the requested service under applicable rules, regulations or orders of the appropriate regulatory authority.

B. Shipper shall indemnify ~~the~~ Utility and save it harmless from all demands, suits, actions, ~~judgements~~judgments, damages, costs, losses, expenses (including reasonable attorney fees incurred enforcing this indemnity obligation or defending a third party claim) and regulatory proceedings, arising from breach of these representations and warranties.

10.2 Title: Shipper warrants title to all gas delivered by it to ~~the~~ Utility. Shipper and Utility warrant that each has the right to deliver and redeliver the gas, and that such gas is free from liens and adverse claims of every kind. Shipper shall indemnify and save Utility harmless against all loss, damage, claims and expense of every character with respect to gas delivered by it on account of royalties, taxes, payments, liens or other charges arising before or created upon delivery of the gas.

10.3 Firm Delivery: Shipper represents that gas supplies necessary to cover the maximum firm peak day requirement as represented by the total MDDQ plus U&UAF in the Agreement shall be supplied on a firm basis. The firmness of such gas supplies shall be reviewed by the Montana Public Service Commission (Commission) upon complaint.

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ON SYSTEM
GENERAL TERMS AND OPERATING CONDITIONS

11. RESPONSIBILITY FOR GAS:

Utility shall be deemed to be responsible for all gas from the time that such gas is received by it at the Point(s) of Receipt to the time that it is delivered at the Point(s) of Delivery. Utility's responsibility with respect to Shipper's gas shall be deemed to be met if ~~the~~ Utility exercises ordinary care in protecting such gas.

12. TERMINATION:

~~The~~ Utility's obligation to provide service, and Shipper's contractual right to receive such service, shall terminate on the earlier of: (a) the date provided in the applicable Agreement for the termination of said service~~:~~; or (b) the date on which ~~the~~ Utility determines on a nondiscriminatory basis to cease transporting gas. Further, the Agreement may be terminated or renegotiated as to the applicable terms at any time by Shipper or ~~the~~ Utility, each in their sole discretion, if the ~~Montana Public Service~~ Commission ~~(MPSC)~~ or the FERC, whichever~~,~~ is applicable, determines that the rates of fees per dekatherm as provided in the Agreement are not in accordance with the ~~MPSC's~~Commission's or the FERC's regulations or governing statutes, or are not fair and equitable to all parties. ~~The~~ Utility reserves the further right to unilaterally terminate or temporarily suspend service ~~if the~~ Utility, in the reasonable exercise of its sole discretion, determines that such service is injurious to the physical operation of any ~~of the~~ Utility facilities or ~~if a~~ Shipper does not comply with any provisions contained in this Rate Schedule or Agreement. Shipper shall not be entitled to transportation service under the Agreement or otherwise, subsequent to the effective date of any termination hereunder.

13. LIABILITY OF PARTIES:

~~The~~ Utility and Shipper each assume full responsibility and liability for the maintenance and operation of its respective properties and equipment and shall indemnify and save harmless the other party from all liability and expense due to any and all damage, claims or actions, including injury or death of persons, arising from any act or accident in connection with installation, presence, maintenance and operation of the property and equipment of the indemnifying party save and except such damage, claim or action caused by the negligence of the party otherwise to be indemnified hereunder.

14. TAXES:

All production (including ad valorem-type production taxes), gathering, delivery, sales, severance, or other excise taxes or assessments upon the gas delivered hereunder by Shipper to ~~the~~ Utility, which are now or hereafter in existence or authorized for collection by any state or other governmental agency or duly constituted authority, either directly or indirectly, shall be paid or caused to be paid by Shipper. Shipper shall be responsible for all taxes imposed upon the transportation of the gas to be transported hereunder, and shall reimburse ~~the~~ Utility for any such taxes incurred by or assessed to ~~the~~ Utility.

(continued)

NATURAL GAS TARIFF

NorthWestern Energy

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Canceling		Revised	Sheet No.	95.12

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ON SYSTEM
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15. BALANCING:

15.1 Balancing Obligations: ~~The~~ Shipper shall be responsible for monitoring and making the necessary adjustments to maintain net receipts (daily receipts less Fuel Reimbursement) at a rate equal to deliveries. ~~The~~ Utility may take any action it deems necessary, intended to maintain an equal balance between daily net receipts and daily deliveries. By the ~~10th~~15th day of the month following the month of gas flow, ~~the~~ Utility will notify Shipper of Shipper's previous month's imbalance. Imbalances between net receipts and deliveries will be treated as set forth in this Section. Subject to Section 15.2, it is recognized that the parties may be unable to control exactly the quantities of gas received and delivered on any day and that the quantities received by ~~the utility~~Utility from ~~a shipper~~Shipper may vary from the quantities delivered on any day to such Shipper.

15.2 Monthly Imbalances:

A. Cumulative monthly imbalance volumes, expressed as a percentage of total monthly actual deliveries of ten percent (10%) or less, will be carried forward to the following month.

B. Cumulative monthly imbalance volumes expressed as a percentage of total monthly actual deliveries which are greater than 10% may be treated as Cash Out Volumes~~. Cash Out Volumes may be traded between Shippers, purchased by~~ at the discretion of Utility ~~from Shipper or sold by the~~. If Utility ~~to Shipper~~declares the imbalance as ~~follows:~~subject to Cash Out, it must notify the Shipper via email of the specific Cash Out Volume.

~~1. Shippers interested in trading Cash Out Volumes shall provide written notice to the Utility requesting placement on the Cash Out Volume trading list. This notice will remain in effect until changed by~~C. If Shipper~~.~~

~~2. By the 10th day of the month, the Utility shall provide a Cash Out Volume trading list, identifying the Shipper, naming its trading contact, and specifying positive or negative imbalance status (excluding volumes) to all Shippers with Cash Out Volumes from the preceding month.~~

~~3. Shippers agreeing to trade Cash Out Volumes shall both provide written notice to the Utility, stating the applicable volume to be traded and the counterparty Shipper. Such written notice shall be deemed to be the Shipper's approval to allow the Utility to make the Cash Out Volume trade on Shipper's behalf.~~

(continued)

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~~4. All contractual arrangements, exchange of consideration, documentation, and cash out pricing shall be the responsibility of the trading Shippers.~~

~~5.~~ ~~If,~~ does not eliminate the Cash Out Volume by the last day of the month in which Shipper receives notice of ~~a Cash Out Volume, the Utility does not receive corresponding written notices from Trading Shippers which document the Cash Out Volume trade, or if the Shipper's trade does not eliminate the Shipper's total Cash Out Volume, the Cash Out Volume shall~~ the Cash Out Volume, the Cash Out volume will be treated in the following manner:

a. Positive Cash Out Volumes: Utility shall purchase positive Cash Out Volumes from Shipper at the lowest weighted average daily price*, as defined below, during the month the Cash Out Volume was created.

b. Negative Cash Out Volumes: Utility shall sell negative Cash Out Volumes to Shipper at the highest weighted average daily price*, as defined below, plus $0.20/~~dekatherm~~Dekatherm, during the month the Cash Out Volume was created.

* The weighted average daily price shall be that USD price per dekatherm reported in the Canadian ~~Natural~~ Gas ~~Daily Outlook under~~ "Price Reporter for the AECo/NIT ~~Energy Exchange Inc. (EEI) same day trading." This price will be converted to a price per dekatherm in U.S. dollars by multiplying the price per gigajoule by 1.054615 and converting from Canadian to U.S. funds using the exchange rate reported in Canadian Natural Gas Daily Outlook for the applicable day.~~ pricing point for the applicable day(s)... For Shippers with deliveries in Billings and Laurel Montana, the weighted-average daily price shall be that price reported in ~~gas daily under the "daily price survey" daily midpoint, for delivery in~~ Platt's Gas Daily for the Rocky Mountain/CIG ~~(N Syst.).~~ pricing point for the applicable day(s).

c. Cash Out Accounting: A statement documenting the disposition of any Cash Out Volume will be included with Shipper's monthly transportation invoice for the month following the month in which the Cash Out Volume was created.

15.3 Imbalances During Extreme Operating Conditions: The restricted operating conditions which ~~the~~ Utility is authorized to impose in accordance with this provision shall be applicable during any period in which ~~the~~ Utility declares a Constrained Operating Time or a Critical Operating Time as defined in this section. ~~The~~ Utility may declare restricted operating conditions during periods of Extreme Operating Conditions as follows:

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NATURAL GAS TARIFF

NorthWestern Energy

	1st	Revised	Sheet No.	95.14
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A. Constrained Operating Time: A Constrained Operating Time may be declared when, in ~~the~~ Utility's sole judgment, general system flexibility cannot be afforded to Shippers to accommodate minor daily imbalances.

B. Critical Operating Time: ~~A~~Utility may declare a Critical Operating Time~~ may be declared in the Utility's sole judgment:~~ :

1. When the total physical deliveries from all, or a portion of, the system are approaching, or expected to approach, a level that is in excess of the total physical receipts and the maximum volumes of gas available to be withdrawn from ~~the~~ Utility's storage facility without jeopardizing the integrity ~~of the~~ Utility's storage facility; or

2. When system pressures on one or more pipeline segments are falling and approaching a level, or are expected to fall and approach a level, that is at or below the minimum level ~~the~~ Utility considers necessary for system integrity.

~~C.~~ Notice: ~~The~~ Utility will notify ~~shippers~~Shippers at least 20 hours prior to the start of a gas day in which an extreme operating condition is declared. For example, ~~the~~ Utility must give notice by 12:00 p.m. for an extreme operating condition to be effective at 8:00 a.m. on the following day. ~~The~~ Utility may declare a Critical Operating Time during the weekend only when a Constrained Operating Time was in effect on Friday. The only exception to the requirements to notify Shippers within the time frames noted is in the event of an unanticipated system emergency. ~~The~~ Utility shall provide the reasons for the extreme operating conditions to all shippers via telephone~~, facsimile or other electronic means.~~ and/or email. Extreme operating conditions shall be effective at the start of the day and continue day to day thereafter until ~~the utility~~Utility notifies ~~shippers~~Shippers that the extreme operating condition no longer exists.

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15.4 Imposition of Daily Balancing Penalties:

A. Daily balancing penalties shall not be imposed during Constrained Operating Times.

B. Daily balancing penalties shall be imposed during Critical Operating Times as follows:

1. Negative Daily Imbalances: Shippers with negative daily imbalances greater than 2% of actual deliveries will be charged the Balancing Penalty Rate set forth on the applicable rate schedule for all imbalance volumes greater than 2% of actual deliveries. The payment of a penalty pursuant to this section shall under no circumstances be considered as providing any Shipper the right to take imbalance volumes. ~~The~~ Shipper's payment of a penalty does not eliminate the imbalance. At the conclusion of the month, Shipper's imbalance shall continue to be subject to the provisions of 15.2 with respect to any such monthly imbalances.

2. Positive Daily Imbalances: Shippers with positive daily imbalances greater than 2% of actual deliveries will receive a ~~prorata~~pro rata share of any balancing penalty funds received from Shippers with negative daily imbalances during the same period. In no event will the penalty funds paid to ~~the~~ Shipper exceed the value of the imbalance above 2% multiplied by the Balancing Penalty Rate. Any daily imbalance volumes that result in Shipper receiving imbalance penalty funds will be cleared from ~~the~~ Shipper's account.

~~B.~~ C. Points of Receipt: ~~The~~ Utility shall specify in the notice of Critical Operating Time, Point(s) of Receipt that are eligible to receive balancing penalty funds. A confirmed nomination will be allocated to Shipper's accounts at Point(s) of Receipt where an ~~operational balancing agreement~~Operational Balancing Agreement (OBA) exists between ~~the~~ Utility and the upstream Party. Point(s) of Receipt without an ~~operational balancing agreement~~OBA will be allocated based on actual flow. Negative imbalance penalties will be based on actual flow at Point(s) of Receipt without an ~~operational balancing agreement~~OBA, even though actual flow information may not be known until after the Critical Operating Time. Shipper shall be responsible for coordinating and monitoring the gas flow information, as necessary, to avoid a negative imbalance. The Utility is under no obligation to enter into ~~operational balancing agreements.~~an OBA. During Critical Operating Times, the Utility will ~~fax~~email a notice to Shippers, documenting confirmed nominations at Point(s) of Receipt with ~~operational balancing agreements~~OBAs within 4 hours of confirming nominations with the upstream party.

15.5 Imbalances With Other Parties: ~~The~~ Utility shall not be responsible for eliminating any imbalances between Shipper and any third party, including imbalances between local distribution

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companies and specific end users. Furthermore, ~~the~~ Utility shall not be obligated to deviate from its standard operating and accounting procedures in order to reduce or eliminate any such imbalances.

15.6 Balancing Upon Termination: Upon termination of the Agreement, any existing cumulative imbalance shall be eliminated by the delivery of gas at the earliest practicable date, not to exceed 30 days following such termination. If at the end of the 30-day period an imbalance exists, the imbalance will be resolved in accordance with the Cash Out Volume procedure set forth in Section 15.2.

16. SERVICE AGREEMENT:

16.1 Form: Shipper shall enter into a contract with ~~the~~ Utility utilizing ~~the~~ Utility's appropriate standard form of Agreement.

16.2 Term: The term of the Agreement shall be agreed upon between Shipper and ~~the~~ Utility at the time of the execution thereof.

16.3 Miscellaneous: ~~The~~ Utility reserves the right to tailor Agreements to individual needs of ~~the~~ Shipper and ~~the~~ Utility at the time of the Agreement; however, any specific Agreement requirements will not unduly discriminate against or unnecessarily restrict access to any Shipper.

16.4 Modification: ~~The~~Subject to Commission approval, Utility shall have the right at any time and from time-to-time to amend, modify or cancel any and all of the provisions of this Rate Schedule without liability to or consent from any Shipper.

16.5 Further Conditions: Transportation and storage service shall be subject to such further conditions as are contained in the Agreement.

16.6 Large Variable Load Shippers may require unique individual agreements and facilities to meet their dynamic load requirements. N

17. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY:

17.1 Priority 1 - Firm Transportation and Storage Service: ~~The~~ Utility shall supply service first to its firm Shippers and firm sales customers. If full service cannot be provided, ~~the~~ Utility shall provide service on a ~~prorata~~pro rata basis according to ~~the~~ Shipper's MDDQ as specified in ~~the~~ Shipper's executed Agreement. Firm transportation and storage services~~,~~ will be treated on a ~~prorata~~pro rata basis with firm sales service for purposes of allocating available capacity~~. Except~~

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except that ~~the~~ Utility shall have the right to deviate from this procedure when, in its sole discretion, it is necessary to do so to mitigate threats to the public health and safety.

17.2 Priority 2 - Interruptible Transportation: After Priority 1 requirements are satisfied, ~~the~~ Utility will provide interruptible service in the following manner:

The higher priority and the last to be interrupted will be accorded to interruptible service which is being performed under an Agreement with the highest rate. Within this priority, service shall be interrupted using Service Date as the basis so that services which are provided pursuant to later Service Dates will be interrupted before service performed pursuant to earlier Service Dates. If changes to the GTC-1 require new transportation service agreements, the service dates in active transportation service agreements will carry forward to the new transportation service agreements.

~~The~~ Utility shall have the right, in its sole discretion, to deviate from the interruptible procedure previously described when (1) necessary for system stability and/or operational reasons and (2) following the above procedures would cause an interruption in service to a Shipper who is not contributing to the problem on ~~the~~ Utility's system.

17.3 Allocation of Capacity: If the demand for new firm capacity which includes but is not limited to receipt point capacity, transmission capacity, distribution capacity and storage capacity is greater than the available capacity, the available capacity will be allocated on a ~~prorata~~pro rata basis between Shippers and firm sales service. The applicable firm MDDQ will be used for allocating receipt point capacity, transmission capacity, distribution capacity, storage capacity and deliverability. For purposes of establishing the firm sales MDDQ to be used in the allocation, the most recent filing before the Commission which sets forth the necessary information will be utilized. Firm capacity and deliverability under active transportation and storage service agreements will not be affected by this provision.

17.4 Miscellaneous:

A. Shipper and Utility shall collaborate in making receipt and delivery adjustments, if possible, which may be necessary to protect life, health and safety.

B. Upon expiration of the Agreement, Shipper's Service Date will terminate.

18. GENERAL OPERATING PROVISIONS:

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18.1 Requests for Services: Service hereunder shall be requested by providing the required information to ~~the~~ Utility, in writing utilizing Utility's Request for Service Form.

18.2 Estimates: Upon request of Utility, Shipper shall from time-_to-_time submit estimates of daily, monthly and annual quantities of gas to be transported, including peak day requirements.

18.3 Reservation Charges for Firm Services: The Reservation Charge is the demand component of the firm service rate schedules. This charge reserves the capacity needed by ~~these~~ Shippers to supply their non-curtailable peak day load. Shipper must contract for a level of firm capacity necessary to supply its non-curtailable and non-interruptible peak day requirement. If Shipper exceeds its contracted MDDQ, its MDDQ will be automatically adjusted upward to equal ~~Shippers~~Shipper's most recent peak day use. The Firm Transportation Service Agreement will be amended to reflect the higher MDDQ effective the first day of the month in which the new peak day occurred. These automatic upward MDDQ adjustments are intended to correct for minimal increases in load due to weather and nominal growth of existing loads. These adjustments are not intended to correct for planned new load growth. Shippers must use appropriate due diligence to ensure that capacity for all planned new load growth is contracted for at the time the growth occurs rather than waiting for the automatic MDDQ adjustments to occur sometime after the growth occurs. Adjusting MDDQs at the time load growth occurs will not only ensure timely MDDQ adjustments, but will also ensure that potential capacity issues are addressed on a timely basis. The revised MDDQ will be effective until October 1 of each year subject to change during June 1 through August 1 of each year. Shippers desiring to reduce their MDDQ must notify the Utility between June 1 and August 1 with a written request to reduce the MDDQ effective October 1 and the justification for reducing the MDDQ. ~~The~~ Utility will make the final decision regarding the MDDQ level; however a request may not be unreasonably denied.

18.3 Unauthorized Use: For Shippers that have contracted for both firm and interruptible transportation services or interruptible transportation service only, if Utility curtails any or all of the interruptible transportation and Shipper fails to curtail to the level specified by Utility~~, the~~ Shipper shall pay an Unauthorized System Use Charge as set forth in the applicable tariff on the volumes Shipper failed to curtail. ~~The~~ Utility will notify Shippers at least 20 hours prior to the start of a gas day in which an Unauthorized Use Charge will be imposed. For example, ~~the~~ Utility must give notice by 12:00 p.m. for the Unauthorized Use Charge to be effective at 8:00 a.m. on the following day. ~~The~~ Utility can only impose the Unauthorized Use Charge during the weekend if a Constrained Operating Time was in effect on Friday. The only exception to the requirements to notify Shippers within the time frames noted would be in the event of an unanticipated system emergency. ~~The~~ Utility shall provide notice stating the reasons for imposing the Unauthorized Use Charge to Shippers via telephone~~, facsimile or other electronic means.~~ and/or email. The imposition

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of Unauthorized Use Charges shall be effective at the start of the day and continue day to day thereafter until ~~the~~ Utility notifies Shippers that the Unauthorized Use Charges no longer apply.

18.5 Nominations: Nominations for transportation of gas and storage injections and withdrawals must be received by 12:00 ~~P.M~~p.m. one working day (excluding weekends and scheduled holidays) prior to the commencement of service. ~~during~~During all extreme operating conditions, late nominations will be accepted if ~~the utility~~Utility is able to confirm and schedule the nominated volumes with the interconnecting pipeline(s). Nominations must be placed in a manner specified by ~~the~~ Utility and transmitted electronically to the Gas Transportation Department. Nominations submitted after the deadline or nominations not submitted in the manner specified by ~~the~~ Utility may be rejected at the sole discretion of ~~the~~ Utility. The nomination will remain in effect until a revised nomination is received by ~~the~~ Utility. If ~~the~~ Utility is unable to confirm the nomination, Shipper will be notified as soon as the problem is identified by ~~the~~ Utility. Any discrepancy in nominations that cannot be resolved shall result in Shipper receiving the lesser of the nominated volume or the volume confirmed with the interconnecting party. ~~The~~ Utility shall have the right to require nomination changes that ensure net receipts and deliveries match. Nominations will be scheduled in the following order: 1) Firm transportation service at —Primary Point(s) of Receipt, 2) Firm Transportation Service at Secondary Points of Receipt, 3) Interruptible Transportation at all Point(s) of Receipt, 4) Imbalance resolution gas. If it becomes necessary to allocate within specific classes as noted above, Shippers will be allocated a proportionate share of the receipt point capacity as follows:

$$\frac{\text{Shippers nominated volume}}{\text{Total nominated volume to be allocated}} \times \text{Receipt Point Capacity to be allocated} = \text{Allocated Volume}$$

A confirmed nomination at Point(s) of Receipt with an ~~operational balancing agreement~~Operational Balancing Agreement (OBA) will result in the confirmed nomination being allocated to ~~the~~ Shipper's account. At Point(s) of Receipt without an ~~operational balancing agreement~~OBA, volumes will be allocated on the basis of actual metered volumes using a predetermined allocation if more than one Shipper is nominating at the applicable Point of Receipt. ~~The~~ Utility reserves the right to reject any nomination not within ~~the~~ Utility's ability to monitor.

18.6 Creditworthiness: ~~The~~ Utility shall not be required to perform or to continue service on behalf of any Shipper who is or has become insolvent or ~~who, at the Utility's request, falls~~ within a reasonable time period ~~to demonstrate~~has not demonstrated creditworthiness by providing ~~at least two (2) of the items listed below:~~ the following information:.

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- Audited financial statements of Shipper or its guarantor for the two (2) most recent preceding years showing ~~good~~acceptable financial strength as determined by ~~the~~ Utility in its sole discretion.

- ~~A~~Senior unsecured long-term ~~bond or commercial paper rating~~ ratings from Standard and Poor's or Moody's ~~equivalent to a "Ba" or better.~~ rating agencies.

~~An estimated financial strength rating by Dun and Bradstreet sufficient to cover the credit to be extended and a corresponding Dun and Bradstreet composite credit appraisal of "fair" or better.~~

~~A demonstration by Shipper that it has sufficient financial capacity or backing to warrant an extension of credit. This demonstration could include proof of banking relationships sufficient to cover the Agreement, or a detailed listing of credit reference within the industry, exhibiting a good credit history.~~

- ~~Shipper~~ Such other documentation as Utility shall reasonably request in connection with the service being requested.

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- If Utility has determined Shipper is not creditworthy based on information provided above, Shipper may receive service if Shipper ~~prepays~~provides a cash deposit, letter of credit, or creditworthy guarantor for such service in an amount equal to the cost of performing the maximum level of service ~~requested~~request by Shipper for a four- (4) month period.

~~18.7 Delivery to Third Party Storage Facilities: Shipper can nominate for delivery to third party storage facilities under the following conditions. The storage facility must be connected to the Utility's gas transmission system and the flow of gas to the third party storage is in the same general flow path as set forth in the Shipper's transmission service agreement between Point(s) of Receipt and Point(s) of Delivery. The Utility is under no obligation to incur any costs to provide delivery to third party storage. The payment of transportation charges as set forth in the Stop-in-Time Accounting Procedure in Rate Schedule T-FSG-1 will apply to gas delivered to third party storage.~~

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- A letter of credit form must be acceptable to Utility and issued by a U.S. commercial bank or a foreign bank with a U.S. branch office. Such bank shall have a Moody's credit rating of at least "A3" and a Standard and Poor's credit rating of at least "A-".

18.7 Planning:

(continued)

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A. Short Term Planning – Before November first of each year, Utility shall request from each Shipper a detailed accounting of its upcoming winter peak market and the firm supplies Shipper plans on utilizing to cover this market. If Shipper does not have enough firm supply to meet its peak market, Shipper will be informed of the penalties it could be subject to under Section 15.4 of these General Terms and Operating Conditions. Additionally, Utility at its discretion may report such shortages to the Commission. Utility may also report to the Commission a Shipper's refusal to provide the required accounting of its peak markets and related supplies.

B. Long Term Planning – On a biennial basis, Utility shall make a formal request of its customers and Shippers for their 10-year forward looking load forecasts and the on-system and off-system resources that will be used to serve those loads. Utility will study the information from these load forecasts in conjunction with similar data from Utility's Energy Supply Function to determine potential resource constraints. Utility will develop, communicate and implement plans for resolving resource constraints as appropriate.

18.8 Miscellaneous:

A. ~~The~~ Utility shall not be required to perform or continue service on behalf of any Shipper that fails to comply with the terms contained in this Rate Schedule.

B. Shipper shall not be entitled to receive service if Shipper is not current in its payments to ~~the Utility~~NorthWestern Energy for natural gas or electric ~~Utility~~utility service, or any charge, rate or fee authorized by the Commission for transportation service; provided, however, if the amount not current pertains to a bona fide dispute, including but not limited to force majeure claims relating to transportation or storage of gas hereunder, Shipper shall be entitled to receive or continue to receive service if Shipper posts a bond satisfactory to ~~the~~ Utility to cover the payment due ~~the~~ Utility.

C. In the event of any penalty that would otherwise be applicable under these provisions as a direct consequence of any action or failure to take action by ~~the~~ Utility or the failure of any facility under ~~the~~ Utility's control, or an event of force majeure as defined in this Rate Schedule, said penalty shall not apply.

D. ~~The~~ Shipper warrants that it will not take any actions that would subject ~~the~~ Utility to the jurisdiction of the FERC, the Department of Energy ~~(DOE)~~ or any successor government agency; provided, however, that service in accordance with ~~the~~ Utility's Order 63 certificate will not be considered a breach of this warranty.

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19. POOLING

19.1 Purpose: The purpose of pooling is to allow Shippers to combine the requirements of eligible facilities (pursuant to ~~definition~~Definition 1-15 in Rule No. 1) and contract for transportation services necessary to meet the combined requirements under one agreement subject to any operational constraints identified by ~~the~~ Utility. Administratively, the combined requirements will be treated as one transaction for purposes of nominating, billing and managing imbalances. Pooling provides an option for eligible facilities to access transportation services without contracting individually with ~~the~~ Utility.

19.2 Conditions of Transportation Service:

A. Shipper will be required to submit a request for transportation service form per delivery location.

B. ~~The Utility will maintain a date and time stamped log documenting when fully completed transportation requests are received by the utility. The~~ ____Utility will attempt to tender transportation contracts in the order that transportation requests are received. ~~A date and time stamped log documenting when transportation contracts are tendered will also be maintained by the Utility.~~

C. The primary term for transportation contracts will be a minimum of one year and will continue year to year thereafter unless terminated upon at least 30 days written notice prior to the end of the primary term or any succeeding year, unless ~~customer~~Shipper is physically disconnecting from ~~the~~ Utility's system. In this event, ~~customer's~~Shipper's contract can be terminated upon 30 days written notice prior to disconnection~~. Customer must remain disconnected from the Utility's system for a minimum of 90 days, or the contract will be reinstated~~.

~~D. The~~ ____D.____Utility will order the necessary metering equipment upon receipt of an executed transportation contract. If as a condition of service, facilities are required that are not included in the meter charge, ~~the~~ Utility will set forth the estimated cost of said facilities and any additional charges to be paid by ~~the shipper. A date and time stamped log will be maintained by the Utility documenting when executed transportation contracts are received by the Utility.~~ Shipper.

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E. Approximately 45 days from the date ~~the utility~~Utility receives an executed transportation contract, the electronic metering equipment will be installed. ~~The~~ Utility's ability to meet this requirement will be subject to workloads, weather conditions and delivery of electronic metering equipment. Transportation services will commence when the necessary metering facilities and communication lines are installed and functioning.

F. To the extent possible, ~~the~~ Utility will endeavor to order, schedule and install metering equipment in the order in which executed transportation contracts are received.

~~G. The logs noted in this Section will be available for public inspection during normal business hours. The logs will also be available for review at NorthWestern Energy's internet web site.~~

20. DISTRIBUTION NETWORK TRANSPORTATION SERVICE:

20.1 Distribution network transportation service provides Shippers with the ability to combine distribution Point(s) of Delivery served in the same Zone, as ~~defined below~~such Zones are defined in the Therm Billing Zones drawing on file with the Commission, and use the combined firm capacity on the transmission and distribution systems to serve the combined daily load. The combined MDDQ will be used in administering transportation services, except that the Unauthorized Use Charge will continue to be assessed on an individual Point of Delivery basis.

20.2 The ~~MDDQ~~MDDQs for distribution level customers using 100% firm transportation service will be ~~re-determined~~reviewed annually~~, and the new MDDQ~~ to determine if any of these MDDQs should be adjusted. As appropriate, Utility will make recommendations to Shippers to change MDDQs. Upon approval by Shippers, MDDQ changes will become effective October 1. ~~The~~In conducting its review, Utility ~~will use a~~shall compare recent peak day ~~model that forecasts the MDDQ from historical daily consumption.~~ loads by customer to each customer's current MDDQ for reasonableness, taking into account changing load and weather patterns.

20.3 In accordance with Section 18.3, if the combined actual daily consumption exceeds the combined MDDQs for Point(s) of Delivery taking 100% firm service, the MDDQs for the Point(s) of Delivery responsible for the overrun will be increased accordingly.

~~20.4 The Zones are defined as follows: Kalispell Zone – downstream of the Meriwether Tap; Missoula Zone – downstream of the Missoula Tap; Dillon Zone – downstream of the Pipestone Tap; Helena Zone – downstream of Helena Junction Tap and Silver City Tap; Bozeman Zone – east of the Pipestone tap; Lewistown Zone – downstream of the Lewistown Tap; Butte Zone – from the~~

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~~Missoula Tap to the Pipestone Tap; Havre Zone – east of the Telstad Compressor; Great Falls Zone – east of Mainline 3 and south of the Telstad Compressor; and Main Line Zone – Cut Bank to Missoula Tap, Shelby Aden Line, Carway Line and Canadian Telstad Line.~~

21. STANDARDS OF CONDUCT:

~~21.1~~ Purpose: The intent of these standards of conduct is to ~~ensure that the Utility in providing transportation services treat their marketing affiliates as they would any other third party. The standards are also intended to~~ promote fair competition and a level playing field among all ~~participants~~Shippers on ~~the Utility's~~NorthWestern Energy's natural gas transmission system.

~~21.2 Definition: For purposes of this section, marketing affiliate means a company owned by (10% of outstanding shares) or a division of NorthWestern Energy whose primary purpose is to produce and/or market gas and related services.~~

21.1 Definition: NorthWestern Energy's Energy Supply Function which purchases gas on behalf of NorthWestern Energy's core customers (hereinafter "merchant function~~)~~") will not be required to contract for transportation services or operate under the General Terms and Operating Conditions (GTC~~) except as specifically set forth in Section 17 of the GTC for no longer than July 1, 2002.~~). For purposes of these Standards of Conduct, ~~Utility shall include~~ all employees involved in the natural gas utility ~~business~~businesses of: NorthWestern Energy's Transmission Business Unit (TBU), NorthWestern Energy's Energy Supply Function, ~~Utility~~ support personnel listed in Section 21.~~3 (K), which may be part of NorthWestern Energy's shared administrative services division,~~2 (D), and NorthWestern Energy's executive management shall be included.

21.~~3~~2 Standards of Conduct: ~~The~~ Utility shall conduct its transportation business to conform to the following standards:

~~A. The Utility shall apply a tariff provision relating to transportation in the same manner to the same or similarly situated affiliated and nonaffiliated Shipper if there is discretion in the application of the provision.~~

~~B.~~A. ~~The~~ Utility shall uniformly apply tariff provision for all Shippers.

~~C. The Utility shall not, through a tariff provision or otherwise give its marketing affiliates preference over nonaffiliated Shippers in scheduling, transportation, storage, or curtailment priority.~~

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~~D.~~B. ~~The~~ Utility shall process all similar requests for transportation in the same manner and within the same period of time.

~~E.~~C. ~~The~~ Utility shall not disclose to its ~~marketing affiliates or the~~ merchant function or Shippers any information it receives from ~~a nonaffiliated Shipper~~other Shippers for purposes of securing transportation service.

~~F. To the extent the Utility provides information related to transportation of natural gas to its marketing affiliates, it must do so contemporaneously to all Shippers affiliated and nonaffiliated on its system. To the extent the Utility makes available information related to gas sales and marketing to its marketing affiliate it must make that information available to all shippers affiliated and nonaffiliated on its system.~~

~~G. The operating employees of the Utility and the operating employees of its marketing affiliates must function independently of each other. Operating employees include any individual employed or retained by the Utility whose primary job duties involve any of the following gas functions:~~

~~(a) purchasing, marketing or selling;~~

~~(b) scheduling and interrupting or curtailing natural gas;~~

~~(c) determining pipeline transportation capacity or storage capacity;~~

~~(d) pricing of tariff utility products or services.~~

~~H. The Utility shall not condition or tie the provision of any service by it to the use of any service provided by any marketing affiliates.~~

~~I. The Utility shall not provide sales leads to its marketing affiliates and shall refrain from giving any appearance that the Utility speaks on behalf of its marketing affiliates. If a customer requests information about securing its own gas supplies or about gas marketers in general, the Utility shall provide a list of all marketers operating on its system, including its marketing affiliates but the Utility shall not promote its marketing affiliates.~~

~~J. The Utility shall not represent to any customer, supplier, or third party that an advantage will accrue to such customer, supplier or third party in the use of the Utility's services as a result of that customer supplier or third party dealing with its marketing affiliates.~~

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~~K. The Utility and its marketing affiliate(s) must maintain separate books of accounts and records to ensure that separation is both functional and financial. There will be an allocation of costs associated with Utility support personnel between the utility and its marketing affiliates. Utility support~~

D. Support personnel includes any individual employed or retained by ~~the utility~~NorthWestern Energy who is not ~~utility~~ gas operating personnel, including administrative, supervisory management, construction, engineering, accounting, legal, regulatory or financial personnel. ~~The requirement will also ensure regulated ratepayers and other Shippers do not subsidize the marketing affiliate's efforts. The Utility will keep accurate records of cost allocations which will be subject to Commission review upon request.~~

21.~~4~~3 Complaint Procedure: ~~The~~ Utility will endeavor, on an informal basis, to respond to and resolve any complaints by Shippers or potential Shippers. If, however, a Shipper or potential Shipper finds the informal response inadequate for resolution of the concerns or questions a formal complaint may be filed with the ~~Montana Public Service~~ Commission.

22. FILING FEES

Shipper shall reimburse ~~the~~ Utility within ten (10) days of the date of an invoice, for any and all filing fees incurred by ~~the~~ Utility in seeking governmental authorization for service to be provided specifically for Shipper.

23. MISCELLANEOUS PROVISION:

23.1 Waiver of Default: No waiver by either party of any default by the other in the performance of any provisions of an executed Agreement shall operate as a waiver of any continuing or future default, whether of a like or different character.

23.2 Assignability: An executed Agreement shall bind and inure to the respective successors and assigns of the parties thereto, but no assignment shall release either party from such party's obligations without the written consent of the other party, which consent shall not be unreasonably withheld. 23.3 Effect of Headings: The headings used throughout this Rate Schedule, Rate Schedules to which they apply and the executed Agreements are inserted for reference purposes only and are not to be considered or taken into account in construing the terms and provisions of any section nor to be deemed in any way to qualify, modify or explain the effects of any such terms or provisions.

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NATURAL GAS TARIFF

NorthWestern Energy

	Original	Revised	Sheet No.	95.27
Canceling		Revised	Sheet No.	95.27

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SERVICE AND RATES SUBJECT TO COMMISSION JURISDICTION: All rates and service conditions under this Rate Schedule are governed by the rules and regulations of the Public Service Commission of Montana and are subject to revision as the Commission may duly authorize in the exercise of its jurisdiction.

NATURAL GAS TARIFF

NorthWestern Energy

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Canceling		Revised	Sheet No.	95.1

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1. DEFINITIONS: The following terms and abbreviations, when used in these General Terms and Operating Conditions (Rate Schedule No. GTC-1), the Rate Schedules, and the Service Agreements (Agreements), shall have the following meaning:

1.1 "BTU" shall mean British Thermal Unit.

1.2 "Cubic foot of gas" shall mean that quantity of gas which, at a temperature of 60° Fahrenheit and at pressure of 14.9 pounds per square inch absolute, occupies 1 cubic foot.

1.3 "Day" shall mean a period of 24 consecutive hours, beginning and ending at 8:00 a.m. Mountain Time.

1.4 "Dekatherm" shall mean 1,000,000 BTUs.

1.5 "Gas" shall mean natural gas of the quality specified in Section 2 hereof.

1.6 "Gross heating value" shall mean the number of BTUs in a cubic foot of gas as calculated from a gas analysis obtained by gas chromatography. The heating value shall be calculated by summation of the heating values determined by GPA standard 2145. The heating value shall be calculated on a dry basis at a temperature of 60 degrees Fahrenheit and a pressure of 14.9 pounds per square inch absolute.

1.7 "Large Variable Load Shipper" shall mean any Shipper with firm daily consumption over 5,000 dekatherms and with the ability to increase hourly flows at a rate greater than 200 dekatherms per hour.

1.8 "Maximum Daily Delivery Quantity (MDDQ)" shall mean the maximum quantity of gas, after adjustments for compressor station fuel and line losses and other unaccounted for gas, if applicable, which Utility shall deliver to Shipper, or for Shipper's account, at the Point(s) of Delivery on any day.

1.9 "Maximum Daily Receipt Quantity (MDRQ)" shall be the MDDQ that Utility has contracted to receive at the Point(s) of Receipt on behalf of Shipper, including the compressor station fuel, line losses and other unaccounted for gas for any particular day.

1.10 "MCF" shall mean 1,000 cubic feet of gas and shall be measured as set forth in Section 4 hereof.

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1.11 "Month" shall mean a period extending from the beginning of the first day in a calendar month to the beginning of the first day in the next succeeding calendar month.

1.12 "Point(s) of Delivery" shall mean point(s) where Utility delivers gas for the account of Shipper.

1.13 "Point(s) of Receipt" shall mean point(s) where Utility receives gas for the account of Shipper.

1.14 "Primary Point(s) of Receipt" shall mean those point(s) designated as Primary in the Firm Gas Transmission Service Agreement where Shipper is entitled to firm service.

1.15 "Psia" shall mean pounds per square inch absolute.

1.16 "Psig" shall mean pounds per square inch gauge.

1.17 "Secondary Point(s) of Receipt" shall mean points other than Primary Point(s) of Receipt where Utility receives gas for the account of Shipper for transportation under a Firm Gas Transmission Service Agreement.

1.18 "Service Date" shall mean the date Utility receives a formal written request for transportation and/or storage service from Shipper.

1.19 "Shipper" shall mean the party on whose behalf Utility provides transportation or storage service.

1.20 "Therm" - The word "Therm" as used herein shall mean 100,000 Btus. 10 therms is equivalent to one dekatherm.

1.21 "Used and Unaccounted For" (U&UAF) shall mean volumes associated with standard operating procedures in the delivery of gas.

1.22 "Utility" shall mean NorthWestern Energy Transportation Business Unit (TBU).

QUALITY OF GAS:

2.1 General Standards: Gas delivered to Utility shall be merchantable natural gas, at all times complying with the following quality requirements:

A. Gas shall be in its natural state as produced, including all hydrocarbon constituents therein contained except liquid or liquefiable hydrocarbons removed by Shipper. Shipper shall also

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have the right to remove nonhydrocarbon constituents. Shipper may enrich the gas to the extent required to meet the gross heating requirement set forth in paragraph "B" below, and may subject the gas, or permit the gas to be subjected, to compression, cooling, cleaning, dehydration and other processes. If Shipper is transferring gas to Utility transmission line directly, provisions must be made by Shipper to odorize the gas to the requirements set forth in the Department of Transportation publication CFR Title 49 Part 192.625.

B. The gross heating value of gas delivered to Utility shall not be less than 900 BTUs per cubic foot, and shall not be more than 1,200 BTUs per cubic foot. Utility may reject receipt of gas having a gross heating value of less than 900 BTUs per cubic foot or more than 1,200 BTUs per cubic foot. Acceptance of gas not meeting this gross heating value requirement shall not constitute a waiver of Utility's right to reject receipt of nonconforming gas.

C. Gas shall be merchantable and usable by the ultimate consumers without further treatment. In particular, the gas received by Utility hereunder at the Point(s) of Receipt shall be commercially free of dust, gum, gum-forming constituents, gasoline, other objectionable substances, and other solid or liquid matter that may become separated from the gas during transportation or storage and shall conform to the following specifications:

1.	Dust, rust or other solids	None
2.	Carbon dioxide	Not more than 2% by volume
3.	Oxygen	Not more than 10 parts per million or .001% by volume
4.	Hydrogen sulfide	Not more than 1/4 grain per 100 cubic feet
5.	Total sulfur	Not more than 2.0 grains per 100 cubic feet
6.	Temperature	Not more than 120° Fahrenheit.
7.	Water vapor	Not more than 4 pounds of water vapor per 1,000,000 cubic feet of gas
8.	Hydrocarbons	None liquefiable at temperatures in excess of 15(Fahrenheit at pressures up to 1,200 psig.
9.	Nitrogen	Not more than 15% by volume

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D. Unless otherwise agreed, Utility shall not be required to receive at any Point of Receipt gas that is of a quality inferior to that required by a third party at any Point of Delivery.

2.2 Utility's Option to Treat: Utility, at its option, may refuse to accept delivery of any gas not meeting the quality specifications set out in this Section. Thereafter, Shipper shall have the right to conform the gas to the above specification. If Shipper does not elect to conform the gas to the specifications, then Utility may, at its option, accept gas tendered by Shipper which does not meet the specifications above, treat the gas to conform it to the specifications and charge Shipper for the actual cost of such treating, including, but not limited to, capital costs, O&M, fuel and shrinkage. Any Shipper tendering non specification gas shall indemnify Utility for any injury, damage, loss or liability caused by the delivery of such gas, except to the extent Utility knowingly and willingly accepts such non specification gas.

2.3 Hydrogen Sulfide: At Utility's sole discretion, Utility may install, at Shipper's expense, a properly operating hydrogen sulfide monitoring device (H2S monitor) that is capable of curtailing any deliveries to Utility of gas containing hydrogen sulfide in excess of 1/4 grain per 100 cubic feet (4 ppm).

3. PRESSURE:

3.1 Pressure at the Point(s) of Receipt: Shipper shall cause the gas to be tendered at the Point(s) of Receipt at a pressure sufficient to enter Utility's system, provided Shipper shall not, except with the agreement of Utility, be permitted to tender the gas at any Point of Receipt at a pressure in excess of the pressure specified for that Point of Receipt as set forth in the Agreement. If Shipper can supply gas at a higher pressure than the design of the pipeline system, Utility shall install, as a part of the equipment required under Section 4.3 below, pressure limiting devices to ensure the maximum allowable operating pressure (MAOP) of the pipeline shall not be exceeded.

3.2 Pressure at the Point(s) of Delivery: Utility shall cause the gas to be delivered at the Point(s) of Delivery at such pressures sufficient to effect delivery into the receiving facilities against the pressures prevailing from time-to-time.

4. MEASUREMENT AND TESTS:

4.1 Unit of Volume: The unit of volume for all gas measured hereunder shall be 1 cubic foot of gas.

4.2 Billing Unit: The billing unit of the gas transported or stored hereunder shall be one Therm.

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4.3 Ownership of Measuring Equipment: All necessary measuring devices and materials will be furnished, installed, owned, operated and maintained by Utility. Shipper may install and operate check measuring equipment provided it does not interfere with the use of Utility's equipment in determining the volumes of gas being measured.

Utility shall have the option to install additional facilities that are required to provide service. Shipper shall pay, in addition to the rate(s) stated in the applicable Rate Schedule, at Utility's option, the cost of the additional facilities.

If required by Utility for electronic metering, Shipper assumes responsibility for the installation and maintenance costs for a communication line necessary for electronic metering of gas quantities transported.

4.4 Metering and Computation of Volumes: The gas shall be metered by orifice meter, turbine meter, positive displacement meter or combination of meter types in a measurement facility constructed, installed and maintained by Utility at or near the Point(s) of Receipt or Point(s) of Delivery. Such measurement facilities shall be constructed and installed in accordance with the most current provision for the meter type in the applicable American Gas Association Report. The volumes of gas received by or delivered to Utility shall be the volumes received directly from the online measurement device. Such volumes shall be calculated, and corrected volumes from the online measurement device or computed from the meter records will be converted into the units of measurement specified herein in accordance with the methods prescribed by the currently adopted American Gas Association Report for the meter type. Corrections shall be made for gas volume deviation from the Ideal Gas Laws at the pressure and temperature at which the gas is metered. To determine the factors for such correction, a quantitative analysis of the gas shall be made at reasonable intervals with such apparatus as shall be agreed upon by Utility and Shipper, and such factors shall be obtained from data contained in "Manual for the Determination of Supercompressibility Factors for Natural Gas" published by the American Gas Association as report "PAR Research Project NX-19" dated 1962 or "Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases" published by the American Gas Association as "Transmission Measurement Committee Report No. 8" dated November 1992, or any subsequent revision acceptable to Utility and Shipper. For the purpose of measurement and meter calibration in the case of electronic measurement utilizing absolute pressure transducers, the actual atmosphere pressure shall be measured and used during calibration. Otherwise, the average atmospheric pressure will be used for gauge pressure transducers. A barometer or electronic barometer calibrated to a standard shall be used to determine the current atmospheric pressure.

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4.5 Specific Gravity: Tests to determine the specific gravity of the gas being metered shall be performed at reasonable intervals. The gas samples to be tested shall be representative of the gas delivered at the Point(s) of Delivery or Receipt. All such determinations of specific gravity shall be made by using gas chromatography and then calculating the specific gravity of the natural gas. The specific gravity of the gas flowing through each meter determined by the above-mentioned method shall be used in computing the volume of gas delivered through such meter. The specific gravity determined by any test shall apply from the date the test was taken until the date of the next year.

4.6 Temperature: The temperature of the gas delivered at the Point(s) of Receipt or Delivery hereunder, if required, shall be determined by means of standard electronic temperature devices or a recording temperature chart. The arithmetic average of readings recorded during each chart period shall be used in computing the volumes delivered hereunder.

4.7 Equipment Testing: The accuracy of Utility's electronic measuring equipment shall be verified by test, using means and methods generally acceptable in the gas industry, at least annually or otherwise as agreed to by Utility and Shipper. Shipper shall have the right to witness and verify all tests of Utility's measuring equipment. Notice of the time and nature of each test shall be given to Shipper by Utility sufficiently in advance to permit convenient arrangement for the presence of a representative of Shipper. Measuring equipment found to be registering inaccurately shall be adjusted to read as accurately as possible. If Shipper fails to witness any test, the results of the test shall nevertheless be considered accurate until the next test. All tests of such measuring equipment shall be made at Utility's expense, except that Shipper shall bear the expense of tests made at its request if the inaccuracy is found to produce an error of 2% or less in the measurement of gas. Utility will conduct all tests on all equipment operated by Utility.

4.8 Measuring Equipment Out of Repair: If, for any reason, any measuring equipment is inoperative or inaccurate so that the volume of gas measured is not correctly indicated by the reading thereof, and if such reading is in error by more than 2% in the measurement of gas, then the volume of gas measured, during the period such measuring equipment is inoperative or inaccurate, shall be determined by the parties hereto on the basis of the best data available using the first of the following methods which is feasible.

A. By using the registration of any check measuring equipment installed and accurately registering;

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B. By correcting the error if the percentage of error is ascertainable by calibration, test or mathematical calculations: or

C. By comparing measurements made during preceding periods under similar flow conditions when the meter was registering accurately.

An adjustment based on such determination shall be made for such period of inaccuracy as may be definitely known, or if not known, then for one-half the period since the date of the last meter test.

4.9 Gross Heating Value: The gross heating value per cubic foot of gas shall be determined from time to time by Utility at Utility's expense, using an accurately calibrated chromatograph, from samples of the gas taken at the Point(s) of Receipt or Delivery. Shipper shall have the right to witness any and all tests of gross heating value made by Utility. Shipper shall have the right at any time to make or to require Utility to make a special test of the gross heating value of gas delivered hereunder, but Shipper shall bear the expense of any special tests made at its request.

5. INSPECTION OF EQUIPMENT AND RECORDS:

Each party shall have the right to inspect equipment installed or furnished by the other, and the charts and other measurement or test data of the other, at all times during business hours, but the reading, testing, calibration and adjustment of such equipment and changing of charts shall be done only by the party installing or furnishing same. Unless the parties otherwise agree, each party shall preserve all original test data, charts and other similar records in such party's possession, for a period of at least 6 years.

6. BILLING:

6.1 Billing Under Gas Service Rate Schedules: On or before the twentieth (20th) day of each month, Utility shall render a bill to Shipper under the applicable Rate Schedule(s) for the service rendered during the preceding month.

6.2 Statement by Shipper: When information necessary for billing by Utility is in the control of Shipper, Shipper shall furnish such information, estimated if actual is not available, to Utility on or before the 3rd business day of the month following the month service was rendered. If Shipper furnishes estimated information, the actual information shall be furnished to Utility on or before the 6th working day of the month following the month service was rendered.

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7. PAYMENT:

7.1 Adjustment of Billing Error: In the event that an error is discovered in any bill rendered by Utility, the amount of such error shall be adjusted, provided that claim therefore shall have been made within 12 months from the date such bill was rendered. Any claim over 12 months old will not be allowed. The adjustment by either Utility or Shipper shall be made within 30 days of such timely claim.

8. NOTICE OF CHANGES IN OPERATING CONDITIONS:

Utility and Shipper shall assure that each other shall be notified from time to time, as necessary, of expected changes in the rates of delivery or receipt of gas, or in the pressures or other operating conditions, as stipulated to in the Agreement, and the reason for such expected changes, so that they may be accommodated when they occur. Quantities will be delivered at a uniform hourly rate of confirmed nominated quantity divided by 24, unless as determined by Utility, variance from the uniform hourly rate will not be detrimental to the operation of the pipeline or adversely affect other Shippers or Customers.

9. FORCE MAJEURE:

9.1 Notice: A party's obligation to perform shall be suspended in whole or in part: (1) if an event of force majeure occurs; and (2) the affected party provides written notice describing the event to the other as soon as reasonably possible after the event occurs. The affected party shall resume performance when conditions reasonably allow. The affected party shall not be required to make-up performance lost during the force majeure event.

9.2 Definition: The term "force majeure" shall mean acts of god, governmental action, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, hurricanes, tornadoes, storms, storm warnings, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accidents to machinery or lines of pipe, the necessity for making repairs to or alterations of machinery or lines of pipe, freezing of wells or lines of pipe, partial or entire failure of wells or sources of supply of gas, and any other causes, whether of the kind enumerated or otherwise, not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome. This term shall also include: (a) those instances where either party hereto is required to obtain servitudes, rights-of-way grants, permits or licenses to enable such party to fulfill its obligations, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such servitudes, rights-of-way grants, permits or licenses; and (b) those instances where either party hereto is required to furnish materials and supplies for the

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purpose of constructing or maintaining facilities or is required to secure permits or permissions from any governmental agency to enable such party to fulfill its obligations hereunder, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such materials and supplies, permits and permissions.

9.3 Strikes: The settlement of strikes or lockouts shall be within the discretion of the party having the difficulty, and that the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of any opposing party when such course is inadvisable in the discretion of the party having the difficulty.

10. WARRANTIES:

10.1 Eligibility:

A. Any Shipper transporting or storing gas on Utility's system warrants for itself, its successors and assigns that all gas delivered to Utility for service shall be eligible for the requested service under applicable rules, regulations or orders of the appropriate regulatory authority.

B. Shipper shall indemnify Utility and save it harmless from all demands, suits, actions, judgments, damages, costs, losses, expenses (including reasonable attorney fees incurred enforcing this indemnity obligation or defending a third party claim) and regulatory proceedings, arising from breach of these representations and warranties.

10.2 Title: Shipper warrants title to all gas delivered by it to Utility. Shipper and Utility warrant that each has the right to deliver and redeliver the gas, and that such gas is free from liens and adverse claims of every kind. Shipper shall indemnify and save Utility harmless against all loss, damage, claims and expense of every character with respect to gas delivered by it on account of royalties, taxes, payments, liens or other charges arising before or created upon delivery of the gas.

10.3 Firm Delivery: Shipper represents that gas supplies necessary to cover the maximum firm peak day requirement as represented by the total MDDQ plus U&UAF in the Agreement shall be supplied on a firm basis. The firmness of such gas supplies shall be reviewed by the Montana Public Service Commission (Commission) upon complaint.

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11. RESPONSIBILITY FOR GAS:

Utility shall be deemed to be responsible for all gas from the time that such gas is received by it at the Point(s) of Receipt to the time that it is delivered at the Point(s) of Delivery. Utility's responsibility with respect to Shipper's gas shall be deemed to be met if Utility exercises ordinary care in protecting such gas.

12. TERMINATION:

Utility's obligation to provide service, and Shipper's contractual right to receive such service, shall terminate on the earlier of: (a) the date provided in the applicable Agreement for the termination of said service; or (b) the date on which Utility determines on a nondiscriminatory basis to cease transporting gas. Further, the Agreement may be terminated or renegotiated as to the applicable terms at any time by Shipper or Utility, each in their sole discretion, if the Commission or the FERC, whichever is applicable, determines that the rates of fees per dekatherm as provided in the Agreement are not in accordance with the Commission's or the FERC's regulations or governing statutes, or are not fair and equitable to all parties. Utility reserves the further right to unilaterally terminate or temporarily suspend service if Utility, in the reasonable exercise of its sole discretion, determines that such service is injurious to the physical operation of any Utility facilities or if Shipper does not comply with any provisions contained in this Rate Schedule or Agreement. Shipper shall not be entitled to transportation service under the Agreement or otherwise, subsequent to the effective date of any termination hereunder.

13. LIABILITY OF PARTIES:

Utility and Shipper each assume full responsibility and liability for the maintenance and operation of its respective properties and equipment and shall indemnify and save harmless the other party from all liability and expense due to any and all damage, claims or actions, including injury or death of persons, arising from any act or accident in connection with installation, presence, maintenance and operation of the property and equipment of the indemnifying party save and except such damage, claim or action caused by the negligence of the party otherwise to be indemnified hereunder.

14. TAXES:

All production (including ad valorem-type production taxes), gathering, delivery, sales, severance, or other excise taxes or assessments upon the gas delivered hereunder by Shipper to Utility, which are now or hereafter in existence or authorized for collection by any state or other governmental agency or duly constituted authority, either directly or indirectly, shall be paid or caused to be paid by Shipper. Shipper shall be responsible for all taxes imposed upon the transportation of the gas to be transported hereunder, and shall reimburse Utility for any such taxes incurred by or assessed to Utility.

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15. BALANCING:

15.1 Balancing Obligations: Shipper shall be responsible for monitoring and making the necessary adjustments to maintain net receipts (daily receipts less Fuel Reimbursement) at a rate equal to deliveries. Utility may take any action it deems necessary, intended to maintain an equal balance between daily net receipts and daily deliveries. By the 15th day of the month following the month of gas flow, Utility will notify Shipper of Shipper's previous month's imbalance. Imbalances between net receipts and deliveries will be treated as set forth in this Section. Subject to Section 15.2, it is recognized that the parties may be unable to control exactly the quantities of gas received and delivered on any day and that the quantities received by Utility from Shipper may vary from the quantities delivered on any day to such Shipper.

15.2 Monthly Imbalances:

A. Cumulative monthly imbalance volumes, expressed as a percentage of total monthly actual deliveries of ten percent (10%) or less, will be carried forward to the following month.

B. Cumulative monthly imbalance volumes expressed as a percentage of total monthly actual deliveries which are greater than 10% may be treated as Cash Out Volumes at the discretion of Utility. If Utility declares the imbalance as subject to Cash Out, it must notify the Shipper via email of the specific Cash Out Volume.

C. If Shipper does not eliminate the Cash Out Volume by the last day of the month in which Shipper receives notice of the Cash Out Volume, the Cash Out volume will be treated in the following manner:

a. Positive Cash Out Volumes: Utility shall purchase positive Cash Out Volumes from Shipper at the lowest weighted average daily price*, as defined below, during the month the Cash Out Volume was created.

b. Negative Cash Out Volumes: Utility shall sell negative Cash Out Volumes to Shipper at the highest weighted average daily price*, as defined below, plus $0.20/Dekatherm, during the month the Cash Out Volume was created.

* The weighted average daily price shall be that USD price per dekatherm reported in the Canadian Gas Price Reporter for the AECo/NIT pricing point for the applicable day(s). For Shippers with deliveries in Billings and Laurel Montana, the weighted

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average daily price shall be that price reported in Platt's Gas Daily for the Rocky Mountain/CIG pricing point for the applicable day(s).

c. Cash Out Accounting: A statement documenting the disposition of any Cash Out Volume will be included with Shipper's monthly transportation invoice for the month following the month in which the Cash Out Volume was created.

15.3 Imbalances During Extreme Operating Conditions: The restricted operating conditions which Utility is authorized to impose in accordance with this provision shall be applicable during any period in which Utility declares a Constrained Operating Time or a Critical Operating Time as defined in this section. Utility may declare restricted operating conditions during periods of Extreme Operating Conditions as follows:

A. Constrained Operating Time: A Constrained Operating Time may be declared when, in Utility's sole judgment, general system flexibility cannot be afforded to Shippers to accommodate minor daily imbalances.

B. Critical Operating Time: Utility may declare a Critical Operating Time:

1. When the total physical deliveries from all, or a portion of, the system are approaching, or expected to approach, a level that is in excess of the total physical receipts and the maximum volumes of gas available to be withdrawn from Utility's storage facility without jeopardizing the integrity of Utility's storage facility; or

2. When system pressures on one or more pipeline segments are falling and approaching a level, or are expected to fall and approach a level, that is at or below the minimum level Utility considers necessary for system integrity.

C. Notice: Utility will notify Shippers at least 20 hours prior to the start of a gas day in which an extreme operating condition is declared. For example, Utility must give notice by 12:00 p.m. for an extreme operating condition to be effective at 8:00 a.m. on the following day. Utility may declare a Critical Operating Time during the weekend only when a Constrained Operating Time was in effect on Friday. The only exception to the requirements to notify Shippers within the time frames noted is in the event of an unanticipated system emergency. Utility shall provide the reasons for the extreme operating conditions to all shippers via telephone and/or email. Extreme operating conditions shall be effective at the start of the day and continue day to day thereafter until Utility notifies Shippers that the extreme operating condition no longer exists.

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ON SYSTEM
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15.4 Imposition of Daily Balancing Penalties:

A. Daily balancing penalties shall not be imposed during Constrained Operating Times.

B. Daily balancing penalties shall be imposed during Critical Operating Times as follows:

1. Negative Daily Imbalances: Shippers with negative daily imbalances greater than 2% of actual deliveries will be charged the Balancing Penalty Rate set forth on the applicable rate schedule for all imbalance volumes greater than 2% of actual deliveries. The payment of a penalty pursuant to this section shall under no circumstances be considered as providing any Shipper the right to take imbalance volumes. Shipper's payment of a penalty does not eliminate the imbalance. At the conclusion of the month, Shipper's imbalance shall continue to be subject to the provisions of 15.2 with respect to any such monthly imbalances.

2. Positive Daily Imbalances: Shippers with positive daily imbalances greater than 2% of actual deliveries will receive a pro rata share of any balancing penalty funds received from Shippers with negative daily imbalances during the same period. In no event will the penalty funds paid to Shipper exceed the value of the imbalance above 2% multiplied by the Balancing Penalty Rate. Any daily imbalance volumes that result in Shipper receiving imbalance penalty funds will be cleared from Shipper's account.

C. Points of Receipt: Utility shall specify in the notice of Critical Operating Time, Point(s) of Receipt that are eligible to receive balancing penalty funds. A confirmed nomination will be allocated to Shipper's accounts at Point(s) of Receipt where an Operational Balancing Agreement (OBA) exists between Utility and the upstream Party. Point(s) of Receipt without an OBA will be allocated based on actual flow. Negative imbalance penalties will be based on actual flow at Point(s) of Receipt without an OBA, even though actual flow information may not be known until after the Critical Operating Time. Shipper shall be responsible for coordinating and monitoring the gas flow information, as necessary, to avoid a negative imbalance. The Utility is under no obligation to enter into an OBA. During Critical Operating Times, the Utility will email a notice to Shippers, documenting confirmed nominations at Point(s) of Receipt with OBAs within 4 hours of confirming nominations with the upstream party.

15.5 Imbalances With Other Parties: Utility shall not be responsible for eliminating any imbalances between Shipper and any third party, including imbalances between local distribution companies and specific end users. Furthermore, Utility shall not be obligated to deviate from its standard operating and accounting procedures in order to reduce or eliminate any such imbalances.

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ON SYSTEM
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15.6 Balancing Upon Termination: Upon termination of the Agreement, any existing cumulative imbalance shall be eliminated by the delivery of gas at the earliest practicable date, not to exceed 30 days following such termination. If at the end of the 30-day period an imbalance exists, the imbalance will be resolved in accordance with the Cash Out Volume procedure set forth in Section 15.2.

16. SERVICE AGREEMENT:

16.1 Form: Shipper shall enter into a contract with Utility utilizing Utility's appropriate standard form of Agreement.

16.2 Term: The term of the Agreement shall be agreed upon between Shipper and Utility at the time of the execution thereof.

16.3 Miscellaneous: Utility reserves the right to tailor Agreements to individual needs of Shipper and Utility at the time of the Agreement; however, any specific Agreement requirements will not unduly discriminate against or unnecessarily restrict access to any Shipper.

16.4 Modification: Subject to Commission approval, Utility shall have the right at any time and from time to time to amend, modify or cancel any and all of the provisions of this Rate Schedule without liability to or consent from any Shipper.

16.5 Further Conditions: Transportation and storage service shall be subject to such further conditions as are contained in the Agreement.

16.6 Large Variable Load Shippers may require unique individual agreements and facilities to meet their dynamic load requirements.

17. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY:

17.1 Priority 1 - Firm Transportation and Storage Service: Utility shall supply service first to its firm Shippers and firm sales customers. If full service cannot be provided, Utility shall provide service on a pro rata basis according to Shipper's MDDQ as specified in Shipper's executed Agreement. Firm transportation and storage services will be treated on a pro rata basis with firm sales service for purposes of allocating available capacity except that Utility shall have the right to deviate from this procedure when, in its sole discretion, it is necessary to do so to mitigate threats to the public health and safety.

17.2 Priority 2 - Interruptible Transportation: After Priority 1 requirements are satisfied, Utility will provide interruptible service in the following manner:

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The higher priority and the last to be interrupted will be accorded to interruptible service which is being performed under an Agreement with the highest rate. Within this priority, service shall be interrupted using Service Date as the basis so that services which are provided pursuant to later Service Dates will be interrupted before service performed pursuant to earlier Service Dates. If changes to the GTC-1 require new transportation service agreements, the service dates in active transportation service agreements will carry forward to the new transportation service agreements.

Utility shall have the right, in its sole discretion, to deviate from the interruptible procedure previously described when (1) necessary for system stability and/or operational reasons and (2) following the above procedures would cause an interruption in service to a Shipper who is not contributing to the problem on Utility's system.

17.3 Allocation of Capacity: If the demand for new firm capacity which includes but is not limited to receipt point capacity, transmission capacity, distribution capacity and storage capacity is greater than the available capacity, the available capacity will be allocated on a pro rata basis between Shippers and firm sales service. The applicable firm MDDQ will be used for allocating receipt point capacity, transmission capacity, distribution capacity, storage capacity and deliverability. For purposes of establishing the firm sales MDDQ to be used in the allocation, the most recent filing before the Commission which sets forth the necessary information will be utilized. Firm capacity and deliverability under active transportation and storage service agreements will not be affected by this provision.

17.4 Miscellaneous:

A. Shipper and Utility shall collaborate in making receipt and delivery adjustments, if possible, which may be necessary to protect life, health and safety.

B. Upon expiration of the Agreement, Shipper's Service Date will terminate.

18. GENERAL OPERATING PROVISIONS:

18.1 Requests for Services: Service hereunder shall be requested by providing the required information to Utility, in writing utilizing Utility's Request for Service Form.

18.2 Estimates: Upon request of Utility, Shipper shall from time to time submit estimates of daily, monthly and annual quantities of gas to be transported, including peak day requirements.

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18.3 Reservation Charges for Firm Services: The Reservation Charge is the demand component of the firm service rate schedules. This charge reserves the capacity needed by Shippers to supply their non-curtailable peak day load. Shipper must contract for a level of firm capacity necessary to supply its non-curtailable and non-interruptible peak day requirement. If Shipper exceeds its contracted MDDQ, its MDDQ will be automatically adjusted upward to equal Shipper's most recent peak day use. The Firm Transportation Service Agreement will be amended to reflect the higher MDDQ effective the first day of the month in which the new peak day occurred. These automatic upward MDDQ adjustments are intended to correct for minimal increases in load due to weather and nominal growth of existing loads. These adjustments are not intended to correct for planned new load growth. Shippers must use appropriate due diligence to ensure that capacity for all planned new load growth is contracted for at the time the growth occurs rather than waiting for the automatic MDDQ adjustments to occur sometime after the growth occurs. Adjusting MDDQs at the time load growth occurs will not only ensure timely MDDQ adjustments, but will also ensure that potential capacity issues are addressed on a timely basis. The revised MDDQ will be effective until October 1 of each year subject to change during June 1 through August 1 of each year. Shippers desiring to reduce their MDDQ must notify the Utility between June 1 and August 1 with a written request to reduce the MDDQ effective October 1 and the justification for reducing the MDDQ. Utility will make the final decision regarding the MDDQ level; however a request may not be unreasonably denied.

18.4 Unauthorized Use: For Shippers that have contracted for both firm and interruptible transportation services or interruptible transportation service only, if Utility curtails any or all of the interruptible transportation and Shipper fails to curtail to the level specified by Utility Shipper shall pay an Unauthorized System Use Charge as set forth in the applicable tariff on the volumes Shipper failed to curtail. Utility will notify Shippers at least 20 hours prior to the start of a gas day in which an Unauthorized Use Charge will be imposed. For example, Utility must give notice by 12:00 p.m. for the Unauthorized Use Charge to be effective at 8:00 a.m. on the following day. Utility can only impose the Unauthorized Use Charge during the weekend if a Constrained Operating Time was in effect on Friday. The only exception to the requirements to notify Shippers within the time frames noted would be in the event of an unanticipated system emergency. Utility shall provide notice stating the reasons for imposing the Unauthorized Use Charge to Shippers via telephone and/or email. The imposition of Unauthorized Use Charges shall be effective at the start of the day and continue day to day thereafter until Utility notifies Shippers that the Unauthorized Use Charges no longer apply.

18.5 Nominations: Nominations for transportation of gas and storage injections and withdrawals must be received by 12:00 p.m. one working day (excluding weekends and scheduled holidays) prior to the commencement of service. During all extreme operating conditions, late nominations will be accepted if Utility is able to confirm and schedule the nominated volumes with the

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interconnecting pipeline(s). Nominations must be placed in a manner specified by Utility and transmitted electronically to the Gas Transportation Department. Nominations submitted after the deadline or nominations not submitted in the manner specified by Utility may be rejected at the sole discretion of Utility. The nomination will remain in effect until a revised nomination is received by Utility. If Utility is unable to confirm the nomination, Shipper will be notified as soon as the problem is identified by Utility. Any discrepancy in nominations that cannot be resolved shall result in Shipper receiving the lesser of the nominated volume or the volume confirmed with the interconnecting party. Utility shall have the right to require nomination changes that ensure net receipts and deliveries match. Nominations will be scheduled in the following order: 1) Firm transportation service at Primary Point(s) of Receipt, 2) Firm Transportation Service at Secondary Points of Receipt, 3) Interruptible Transportation at all Point(s) of Receipt, 4) Imbalance resolution gas. If it becomes necessary to allocate within specific classes as noted above, Shippers will be allocated a proportionate share of the receipt point capacity as follows:

$$\frac{\text{Shippers nominated volume}}{\text{Total nominated volume to be allocated}} \times \text{Receipt Point Capacity to be allocated} = \text{Allocated Volume}$$

A confirmed nomination at Point(s) of Receipt with an Operational Balancing Agreement (OBA) will result in the confirmed nomination being allocated to Shipper's account. At Point(s) of Receipt without an OBA, volumes will be allocated on the basis of actual metered volumes using a predetermined allocation if more than one Shipper is nominating at the applicable Point of Receipt. Utility reserves the right to reject any nomination not within Utility's ability to monitor.

18.6 Creditworthiness: Utility shall not be required to perform or to continue service on behalf of any Shipper who is or has become insolvent or within a reasonable time period has not demonstrated creditworthiness by providing the following information:.

- Audited financial statements of Shipper or its guarantor for the two (2) most recent preceding years showing acceptable financial strength as determined by Utility in its sole discretion.
- Senior unsecured long-term ratings from Standard and Poor's or Moody's rating agencies.
- Such other documentation as Utility shall reasonably request in connection with the service being requested.

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- If Utility has determined Shipper is not creditworthy based on information provided above, Shipper may receive service if Shipper provides a cash deposit, letter of credit, or creditworthy guarantor for such service in an amount equal to the cost of performing the maximum level of service request by Shipper for a four (4) month period. .

- A letter of credit form must be acceptable to Utility and issued by a U.S. commercial bank or a foreign bank with a U.S. branch office. Such bank shall have a Moody's credit rating of at least "A3" and a Standard and Poor's credit rating of at least "A-".

18.7 Planning:

A. Short Term Planning – Before November first of each year, Utility shall request from each Shipper a detailed accounting of its upcoming winter peak market and the firm supplies Shipper plans on utilizing to cover this market. If Shipper does not have enough firm supply to meet its peak market, Shipper will be informed of the penalties it could be subject to under Section 15.4 of these General Terms and Operating Conditions. Additionally, Utility at its discretion may report such shortages to the Commission. Utility may also report to the Commission a Shipper's refusal to provide the required accounting of its peak markets and related supplies.

B. Long Term Planning – On a biennial basis, Utility shall make a formal request of its customers and Shippers for their 10-year forward looking load forecasts and the on-system and off-system resources that will be used to serve those loads. Utility will study the information from these load forecasts in conjunction with similar data from Utility's Energy Supply Function to determine potential resource constraints. Utility will develop, communicate and implement plans for resolving resource constraints as appropriate.

18.8 Miscellaneous:

A. Utility shall not be required to perform or continue service on behalf of any Shipper that fails to comply with the terms contained in this Rate Schedule.

B. Shipper shall not be entitled to receive service if Shipper is not current in its payments to NorthWestern Energy for natural gas or electric utility service, or any charge, rate or fee authorized by the Commission for transportation service; provided, however, if the amount not current pertains to a bona fide dispute, including but not limited to force majeure claims relating to transportation or storage of gas hereunder, Shipper shall be entitled to receive or continue to receive service if Shipper posts a bond satisfactory to Utility to cover the payment due Utility.

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ON SYSTEM
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C. In the event of any penalty that would otherwise be applicable under these provisions as a direct consequence of any action or failure to take action by Utility or the failure of any facility under Utility's control, or an event of force majeure as defined in this Rate Schedule, said penalty shall not apply.

D. Shipper warrants that it will not take any actions that would subject Utility to the jurisdiction of the FERC, the Department of Energy or any successor government agency; provided, however, that service in accordance with Utility's Order 63 certificate will not be considered a breach of this warranty.

19. POOLING

19.1 Purpose: The purpose of pooling is to allow Shippers to combine the requirements of eligible facilities (pursuant to Definition 1-15 in Rule No. 1) and contract for transportation services necessary to meet the combined requirements under one agreement subject to any operational constraints identified by Utility. Administratively, the combined requirements will be treated as one transaction for purposes of nominating, billing and managing imbalances. Pooling provides an option for eligible facilities to access transportation services without contracting individually with Utility.

19.2 Conditions of Transportation Service:

A. Shipper will be required to submit a request for transportation service form per delivery location.

B. Utility will attempt to tender transportation contracts in the order that transportation requests are received.

C. The primary term for transportation contracts will be a minimum of one year and will continue year to year thereafter unless terminated upon at least 30 days written notice prior to the end of the primary term or any succeeding year, unless Shipper is physically disconnecting from Utility's system. In this event, Shipper's contract can be terminated upon 30 days written notice prior to disconnection.

D. Utility will order the necessary metering equipment upon receipt of an executed transportation contract. If as a condition of service, facilities are required that are not included in the meter charge, Utility will set forth the estimated cost of said facilities and any additional charges to be paid by Shipper.

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ON SYSTEM
GENERAL TERMS AND OPERATING CONDITIONS

E. Approximately 45 days from the date Utility receives an executed transportation contract, the electronic metering equipment will be installed. Utility's ability to meet this requirement will be subject to workloads, weather conditions and delivery of electronic metering equipment. Transportation services will commence when the necessary metering facilities and communication lines are installed and functioning.

F. To the extent possible, Utility will endeavor to order, schedule and install metering equipment in the order in which executed transportation contracts are received.

20. DISTRIBUTION NETWORK TRANSPORTATION SERVICE:

20.1 Distribution network transportation service provides Shippers with the ability to combine distribution Point(s) of Delivery served in the same Zone, as such Zones are defined in the Therm Billing Zones drawing on file with the Commission, and use the combined firm capacity on the transmission and distribution systems to serve the combined daily load. The combined MDDQ will be used in administering transportation services, except that the Unauthorized Use Charge will continue to be assessed on an individual Point of Delivery basis.

20.2 The MDDQs for distribution level customers using 100% firm transportation service will be reviewed annually to determine if any of these MDDQs should be adjusted. As appropriate, Utility will make recommendations to Shippers to change MDDQs. Upon approval by Shippers, MDDQ changes will become effective October 1. In conducting its review, Utility shall compare recent peak day loads by customer to each customer's current MDDQ for reasonableness, taking into account changing load and weather patterns.

20.3 In accordance with Section 18.3, if the combined actual daily consumption exceeds the combined MDDQs for Point(s) of Delivery taking 100% firm service, the MDDQs for the Point(s) of Delivery responsible for the overrun will be increased accordingly.

21. STANDARDS OF CONDUCT:

Purpose: The intent of these standards of conduct is to promote fair competition and a level playing field among all Shippers on NorthWestern Energy's natural gas transmission system.

21.1 Definition: NorthWestern Energy's Energy Supply Function which purchases gas on behalf of NorthWestern Energy's core customers (hereinafter "merchant function") will not be required to contract for transportation services or operate under the General Terms and Operating Conditions (GTC). For purposes of these Standards of Conduct, all employees involved in the natural gas utility businesses of: NorthWestern Energy's Transmission Business Unit (TBU), NorthWestern

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ON SYSTEM
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Energy's Energy Supply Function, support personnel listed in Section 21.2 (D), and NorthWestern Energy's executive management shall be included.

21.2 Standards of Conduct: Utility shall conduct its transportation business to conform to the following standards:

A. Utility shall uniformly apply tariff provision for all Shippers.

B. Utility shall process all similar requests for transportation in the same manner and within the same period of time.

C. Utility shall not disclose to its merchant function or Shippers any information it receives from other Shippers for purposes of securing transportation service.

D. Support personnel includes any individual employed or retained by NorthWestern Energy who is not gas operating personnel, including administrative, supervisory management, construction, engineering, accounting, legal, regulatory or financial personnel.

21.3 Complaint Procedure: Utility will endeavor, on an informal basis, to respond to and resolve any complaints by Shippers or potential Shippers. If, however, a Shipper or potential Shipper finds the informal response inadequate for resolution of the concerns or questions a formal complaint may be filed with the Commission.

22. FILING FEES

Shipper shall reimburse Utility within ten (10) days of the date of an invoice, for any and all filing fees incurred by Utility in seeking governmental authorization for service to be provided specifically for Shipper.

23. MISCELLANEOUS PROVISION:

23.1 Waiver of Default: No waiver by either party of any default by the other in the performance of any provisions of an executed Agreement shall operate as a waiver of any continuing or future default, whether of a like or different character.

23.2 Assignability: An executed Agreement shall bind and inure to the respective successors and assigns of the parties thereto, but no assignment shall release either party from such party's obligations without the written consent of the other party, which consent shall not be unreasonably withheld.

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NATURAL GAS TARIFF

NorthWestern Energy

	Original	Revised	Sheet No.	95.23
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ON SYSTEM
GENERAL TERMS AND OPERATING CONDITIONS

23.3 Effect of Headings: The headings used throughout this Rate Schedule, Rate Schedules to which they apply and the executed Agreements are inserted for reference purposes only and are not to be considered or taken into account in construing the terms and provisions of any section nor to be deemed in any way to qualify, modify or explain the effects of any such terms or provisions.

SERVICE AND RATES SUBJECT TO COMMISSION JURISDICTION: All rates and service conditions under this Rate Schedule are governed by the rules and regulations of the Public Service Commission of Montana and are subject to revision as the Commission may duly authorize in the exercise of its jurisdiction.

Schedule No. AGTC-1

AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

Section	Description
1	Definitions
2	Quality of Gas
3	Pressure
4	Metering and Tests
5	Installations
6	Billing
7	Notice of Changes in Operating Conditions
8	Force Majeure
9	Warranties
10	Responsibility for Gas
11	Termination
12	Liability of Parties
13	Taxes
14	Transmission Allocation
15	Nominations and Market and Supply Balancing
16	Storage
17	Service Agreement
18	Priority of Service and Allocation of Capacity
19	Standards of Conduct
20	Miscellaneous Provisions

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Schedule No. AGTC-1

AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

1. DEFINITIONS: The following terms and abbreviations, when used in these General Terms and Operating Conditions (Rate Schedule No. AGTC-1), the Rate Schedules, and the Service Agreements (Agreements), shall have the following meaning:

1.1 "Aggregation Pool" shall mean the customer group aggregated to meet the requirements of the Core Aggregation Gas Transportation Program.

1.2 "BTU" shall mean British Thermal Unit.

1.3 "Core Aggregator" shall mean the ~~MPSC~~Montana Public Service Commission (Commission) licensed party (Aggregator or Supplier) on whose behalf Utility provides core aggregation services.

1.4 "Cubic foot of gas" shall mean that quantity of gas, which, at a temperature of 60° Fahrenheit and at pressure of 14.9 pounds per square inch absolute, occupies 1 cubic foot.

1.5 "Day" shall mean a period of 24 consecutive hours, beginning and ending at 8:00 a.m. Mountain Time.

1.6 "Dekatherm" shall mean 1,000,000 BTUs.

1.7 "Gas" shall mean natural gas of the quality specified in Section 2 hereof.

1.8 "Gross heating value" shall mean the number of BTUs in a cubic foot of gas as calculated from a gas analysis obtained by gas chromatography. The heating value shall be calculated by summation of the heating values determined by GPA standard 2145. The heating value shall be calculated on a dry basis at a temperature of 60 degrees Fahrenheit and a pressure of 14.9 pounds per square inch absolute.

1.9 "Load Profiling" shall mean a process that utilizes typical customer load shapes to estimate the supply needs of customers without telemetering.

1.10 "Maximum Daily Delivery Quantity (MDDQ)" shall mean the maximum quantity of gas, after adjustments for compressor station fuel and line losses and other unaccounted for gas, if applicable, which Utility shall deliver to Supplier, or for Supplier's account, at the Point(s) of Delivery on any day.

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Schedule No. AGTC-1

AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

1.11 "Maximum Daily Receipt Quantity (MDRQ)" shall be the MDDQ that Utility has contracted to receive at the Point(s) of Receipt on behalf of Supplier, including the compressor station fuel, line losses and other unaccounted for gas for any particular day.

1.12 "MCF" shall mean 1,000 cubic feet of gas and shall be measured as set forth in Section 4 hereof.

1.13 "Merchant Function" shall mean ~~the~~ NorthWestern Energy, which purchases gas on behalf of the Utility's core customers.

1.14 "Month" shall mean a period extending from the beginning of the first day in a calendar month to the beginning of the first day in the next succeeding calendar month.

1.15 "Point(s) of Delivery" shall mean point(s) where Utility delivers gas for the account of Supplier.

1.16 "Point(s) of Receipt" shall mean point(s) where Utility receives gas for the account of Supplier.

1.17 "Primary Point(s) of Receipt" shall mean those point(s) designated as Primary in the Service Agreement where Supplier is entitled to firm service.

1.18 "Psia" shall mean pounds per square inch absolute.

1.19 "Psig" shall mean pounds per square inch gauge.

1.20 "Secondary Point(s) of Receipt" shall mean points other than Primary Point(s) of Receipt where Utility receives gas for the account of Supplier for transportation under a Service Agreement.

1.21 "Supplier" shall mean the ~~MPSC~~Commission licensed party (Aggregator or Supplier) on whose behalf Utility provides core aggregation services.

1.22 "Therm" shall mean 100,000 Btus. 10 therms is equivalent to one dekatherm.

1.23 "Used and Unaccounted For" (U&UAF) shall mean volumes associated with standard operating procedures in the delivery of gas.

1.24 "Utility" shall mean NorthWestern Energy.

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

QUALITY OF GAS:

2.1 General Standards: Gas delivered to Utility shall be merchantable natural gas, at all times complying with the following quality requirements:

A. Gas shall be in its natural state as produced, including all hydrocarbon constituents therein contained except liquid or liquefiable hydrocarbons removed by Supplier. Supplier shall also have the right to remove nonhydrocarbon constituents. Supplier may enrich the gas to the extent required to meet the gross heating requirement set forth in paragraph "B" below, and may subject the gas, or permit the gas to be subjected, to compression, cooling, cleaning, dehydration and other processes. If Supplier is transferring gas to ~~the~~ Utility transmission line directly, provisions must be made by ~~the~~ Supplier to odorize the gas to the requirements set forth in the Department of Transportation publication CFR Title 49 Part 192.625.

B. The gross heating value of gas delivered to Utility shall not be less than 900 BTUs per cubic foot, and shall not be more than 1,200 BTUs per cubic foot. Utility may reject receipt of gas having a gross heating value of less than 900 BTUs per cubic foot or more than 1,200 BTUs per cubic foot. Acceptance of gas not meeting this gross heating value requirement shall not constitute a waiver of Utility's right to reject receipt of nonconforming gas.

C. Gas shall be merchantable and usable by the ultimate consumers without further treatment. In particular, the gas received by Utility hereunder at the Point(s) of Receipt shall be commercially free of dust, gum, gum-forming constituents, gasoline, other objectionable substances, and other solid or liquid matter that may become separated from the gas during transportation or storage and shall conform to the following specifications:

1.	Dust, rust or other solids	None
2.	Carbon dioxide	Not more than 2% by volume
3.	Oxygen	Not more than 10 parts per million or .001% by volume
4.	Hydrogen sulfide	Not more than 1/4 grain per 100 cubic feet
5.	Total sulfur	Not more than 2.0 grains per 100 cubic feet ~~(T)~~

(continued)

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

6.	Temperature	Not more than 120° Fahrenheit.
7.	Water vapor	Not more than 4 pounds of water vapor per 1,000,000 cubic feet of gas
8.	Hydrocarbons	None liquefiable at temperatures in excess of 15 (Fahrenheit at pressures up to 1,200 psig.
9.	Nitrogen	Not more than 15% by volume

D. Unless otherwise agreed, Utility shall not be required to receive at any Point of Receipt gas that is of a quality inferior to that required by a third party at any Point of Delivery.

2.2 Utility's Option to Treat: Utility, at its option, may refuse to accept delivery of any gas not meeting the quality specifications set out in this Section. Thereafter, Supplier shall have the right to conform the gas to the above ~~specification.~~specifications. If Supplier does not elect to conform the gas to the specifications, then Utility may, at its option, accept gas tendered by Supplier which does not meet the specifications above, treat the gas to conform it to the specifications and charge Supplier for the actual cost of such treating, including, but not limited to, capital costs, O&M, fuel and shrinkage. Any Supplier tendering ~~nonspecification~~non specification gas shall indemnify ~~the~~ Utility for any injury, damage, loss or liability caused by the delivery of such gas, except to the extent Utility knowingly and willingly accepts such ~~nonspecification~~non specification gas.

2.3 Hydrogen Sulfide: At Utility's sole discretion, Utility may install, at Supplier's expense, a properly operating hydrogen sulfide monitoring device (H2S monitor) that is capable of curtailing any deliveries to ~~the~~ Utility of gas containing hydrogen sulfide in excess of 1/4 grain per 100 cubic feet (4 ppm).

PRESSURE:

3.1 Pressure at the Point(s) of Receipt: Supplier shall cause the gas to be tendered at the Point(s) of Receipt at a pressure sufficient to enter ~~the~~ Utility's system, provided Supplier shall not, except with the agreement of ~~the~~ Utility, be permitted to tender the gas at any Point of Receipt at a pressure in excess of the pressure specified for that Point of Receipt as set forth in the Agreement. If Supplier can supply gas at a higher pressure than the design of the pipeline system, Utility shall install, as a part of the equipment required under Section 4.3 below, pressure limiting devices to ensure the maximum allowable operating pressure (MAOP) of the pipeline shall not be exceeded.

(continued)

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

3.2 Pressure at the Point(s) of Delivery: Utility shall cause the gas to be delivered at the Point(s) of Delivery at such pressures sufficient to effect delivery into the receiving facilities against the pressures prevailing from time-_to-_time.

4. METERING AND TESTS:

Metering and testing shall be in accordance with ~~the~~ Utility's Natural Gas Service Rules and Regulations Rule Nos. 9 and 11.

5. INSTALLATIONS:

Installations shall be in accordance with ~~the~~ Utility's Natural Gas Service Rules and Regulations Rule Nos. 7 and 8.

6. BILLING:

6.1 If information necessary for billing by ~~the~~ Utility is in the possession of ~~the~~ Supplier, Supplier shall furnish such information 5 business days before the billing date for each Customer.

6.2 If Utility bills for ~~the~~ Supplier's commodity, Supplier shall enter into a separate contract for billing services, and shall be billed in accordance with Rate Schedule No. GBS-1.

6.3 Customer billing shall be in accordance with the Natural Gas Utility's Service Rules and Regulations Rule No. 10.

7. NOTICE OF CHANGES IN OPERATING CONDITIONS:

Utility and Supplier shall assure that each other shall be notified from time-_to-_time, as necessary, of expected changes in the rates of delivery or receipt of gas, or in the pressures or other operating conditions, as stipulated to in the Agreement, and the reason for such expected changes, so that they may be accommodated when they occur.

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

8. FORCE MAJEURE:

8.1 Notice: A party's obligation to perform shall be suspended in whole or in part: (1) if an event of force majeure occurs; and (2) the affected party provides written notice describing the event to the other as soon as reasonably possible after the event occurs. The affected party shall resume performance when conditions reasonably allow. The affected party shall not be required to make-up performance lost during the force majeure event.

8.2 Definition: The term "force majeure" shall mean acts of god, governmental action, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, hurricanes, tornadoes, storms, storm warnings, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accidents to machinery or lines of pipe, the necessity for making repairs to or alterations of machinery or lines of pipe, freezing of wells or lines of pipe, partial or entire failure of wells or sources of supply of gas, and any other causes, whether of the kind enumerated or otherwise, not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome. This term shall also include: (a) those instances where either party hereto is required to obtain servitudes, rights-of-way grants, permits or licenses to enable such party to fulfill its obligations, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such servitudes, rights-of-way grants, permits or licenses; and (b) those instances where either party hereto is required to furnish materials and supplies for the purpose of constructing or maintaining facilities or is required to secure permits or permissions from any governmental agency to enable such party to fulfill its obligations hereunder, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such materials and supplies, permits and permissions.

8.3 Strikes: The settlement of strikes or lockouts shall be within the discretion of the party having the difficulty, and that the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of any opposing party when such course is inadvisable in the discretion of the party having the difficulty.

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

9. WARRANTIES:

9.1 Eligibility:

A. —Any Supplier transporting or storing gas on Utility's system warrants for itself, its successors and assigns~~,~~ that all gas delivered to Utility for service shall be eligible for the requested service under applicable rules, regulations or orders of the appropriate regulatory authority.

B. —Supplier shall indemnify ~~the~~ Utility and save it harmless from all demands, suits, actions, judgments, damages, costs, losses, expenses (including reasonable attorney fees incurred enforcing this indemnity obligation or defending a third party claim) and regulatory proceedings, arising from breach of these representations and warranties.

9.2 Title: Supplier warrants title to all gas delivered by it to ~~the~~ Utility. Supplier and Utility warrant that each has the right to deliver and redeliver the gas, and that such gas is free from liens and adverse claims of every kind. Supplier shall indemnify and save Utility harmless against all loss, damage, claims and expense of every character with respect to gas delivered by it on account of royalties, taxes, payments, liens or other charges arising before or created upon delivery of the gas.

9.3 Firm Delivery: Supplier represents that gas supplies necessary to cover the maximum firm peak day requirement as represented by the total MDDQ plus U&UAF in the Agreement shall be supplied on a firm basis. The firmness of such gas supplies shall be reviewed by the Commission upon complaint.

10. RESPONSIBILITY FOR GAS:

Utility shall be deemed to be responsible for all gas from the time that such gas is received by it at the Point(s) of Receipt to the time that it is delivered at the Point(s) of Delivery. Utility's responsibility with respect to Supplier's gas shall be deemed to be met if ~~the~~ Utility exercises ordinary care in protecting such gas.

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

11. TERMINATION:

11.1 Termination of Agreement:

A. Utility's obligation to provide, and Supplier's contractual right to receive, service shall terminate on the earlier of: (a) the date provided in the applicable Agreement for the termination of service: or (b) the date on which Utility determines, on a nondiscriminatory, basis to cease transporting gas.

B. ~~B.~~ The Agreement between an Aggregator and Utility can be terminated if Aggregator fails to issue payment to ~~the~~ Utility within seven (7) days of issuance of a past due notice, or if Utility receives any notification that Aggregator has filed or will be filing any type of bankruptcy, or closing its business.

~~11.2 Commission Action:~~ Further, the Agreement may be terminated or renegotiated as to the applicable terms at any time by ~~Supplier~~Aggregator or Utility, each in their sole discretion, if the ~~Montana Public Service~~Commission or the Federal Energy Regulatory Commission (~~MPSC or Commission) or the~~ FERC~~,~~), whichever is applicable, determines that the rates or fees per dekatherm as provided in the Agreement are not in accordance with the ~~MPSC's~~Commission's or the FERC's regulations or governing statutes, or are not fair and equitable to all parties.

~~11.3~~C. Utility reserves the further right to unilaterally terminate or temporarily suspend service if Utility, in the reasonable exercise of its sole discretion, determines that such service is injurious to the physical operation of any ~~of the Utility's facilities~~Utility facilities or if Aggregator does not comply with any provisions contained in this Rate Schedule or Agreement. Aggregator shall not be entitled to transportation service under the Agreement or otherwise, subsequent to the effective date of any termination hereunder.

11.2 Commission Action: Agreement may be terminated or renegotiated as to the applicable terms at any time by Supplier or Utility, each in their sole discretion, if the Commission or the FERC, whichever is applicable, determines that the rates or fees per dekatherm as provided in the Agreement are not in accordance with the Commission's or the FERC's regulations or governing statutes, or are not fair and equitable to all parties.

~~11.4~~11.3 Non-Performance: Utility may terminate the Agreement if Supplier is charged balancing penalties for failure to meet the daily confirmed nominations imposed by ~~the~~ Utility 3 times in the first year of the Agreement, or 5 times during the life of the Agreement, or if ~~a~~ Supplier does not comply with any provisions contained in this Rate Schedule, the Agreement, or ~~MPSC~~Commission licensing provisions.

~~11.5~~11.4 Termination of ~~Authorization~~Customer Enrollment Form:

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

A. The ~~Authorization~~Customer Enrollment Form shall remain in effect unless any of the following occurs:
   1. After initial contract term, any party provides 30-day advance written notice of cancellation to Utility and/or the other parties;
   2. Any party goes out of business;
   3. Customer is no longer receiving service at the meter location;
   4. Aggregator cancels service to Customer for Customer's failure to pay for service provided by Aggregator under the Program by sending written notice of cancellation to Utility and Customer;
   5. Utility cancels service to Aggregator for Aggregator's failure to pay for service provided by Utility or for other breach of Contract by sending written notice of cancellation to Aggregator and Customer, pursuant to Section 8. D. below~~.~~;
   6. Aggregator, Customer or Utility files for or is forced into bankruptcy proceedings; or
   7. Change in Utility's tariff rate schedules that materially affect the rights of the parties.

B. Customer shall have 45 days from the date of the cancellation notice by ~~the~~ Aggregator in which to join another Aggregation Pool or return to ~~the~~ Utility's Distribution Services Division. If the Agreement between Aggregator and Utility is canceled and Customer continues to receive service at its meter location, Customer shall be served by Utility's Distribution Services Division and billed in accordance with the tariffs currently being exercised to supply other Customers of such Division, until Customer elects another Aggregator.

C. ~~-~~Customers shall remain responsible ~~to the~~ Utility for any charges incurred by their Aggregator(s) associated with the Program prior to the effective date of service termination.

D. ~~-~~Supplier shall not be entitled to transportation service under the Agreement or otherwise, after the effective date of any termination.

12. LIABILITY OF PARTIES:

Utility and Supplier each assume full responsibility and liability for the maintenance and operation of its respective properties and equipment and shall indemnify and save harmless the other party from all liability and expense due to any and all damage, claims or actions, including injury or death of persons, arising from any act or accident in connection with installation, presence, maintenance and operation of the property and equipment of the indemnifying party save and except such damage, claim or action caused by the negligence of the party otherwise to be indemnified hereunder.

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

13. TAXES:

Supplier shall pay, or cause to be paid, all production (including ad valorem-type production taxes), gathering, delivery, sales, severance, or other excise taxes or assessments upon the gas delivered by Supplier to Utility that are now or hereafter in existence or authorized for collection by any state or other governmental agency or duly constituted authority, either directly or indirectly. Supplier shall be responsible for all taxes imposed upon the transportation of the gas to be transported, and shall reimburse Utility for any such taxes incurred by or assessed to ~~the~~ Utility.

14. TRANSMISSION CAPACITY ALLOCATION:

Utility shall allocate, and Supplier shall accept, a portion of Transmission Capacity for each Aggregation Pool based on the estimated annual load of such Aggregation Pool. Allocations are Customer specific, and shall follow Customer if Customer changes Suppliers. Transmission Capacity shall be equal to 1.01% of the Estimated Annual Load of the Aggregation Pool. In circumstances where actual data and/or load information exist, ~~the~~ Utility, ~~the~~ Customer, or ~~the~~ Supplier may present such evidence and propose to change the Transmission Capacity Allocation for a specific pool. ~~The~~ Utility, in its sole discretion, shall determine if a change in the Transmission Capacity Allocation is warranted.

15. NOMINATIONS AND MARKET AND SUPPLY BALANCING:

15.1 Nominations: ~~Receipt~~Nominations for core aggregation receipts and ~~delivery~~deliveries are performed similarly to other nominations placed on Utility's transmission system.

A. Each week Utility shall ~~be based on estimated annual loads of each aggregated pool. Such~~provide month-to-date usage information that will be used to determine the appropriate nominations ~~shall be calculated by the Utility and shall be used~~ for balancing purposes.

~~A. Delivery nominations as used herein are simple estimations of monthly loads. The monthly loads shall be calculated based on estimated percentages of the total annual loads of each pool, pursuant to Utility's load profiling calculation.~~

B. ~~Receipt nominations shall be based on a percentage of the estimated average daily load of the aggregated pool.~~ At its discretion, Utility may modify receipt nominations to balance storage inventories, adjust for weather variations, or for other operational reasons. At no time shall the receipt nomination exceed the aggregated pool's MDDQ plus fuel U&UAF unless mutually agreed to by Utility and Supplier. During Critical Operating Times, the receipt nominations shall default to the aggregated pool's MDDQ plus any fuel reimbursement, less the aggregated pool's storage MDDQ.

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

15.2 Monthly Imbalances:

A. Cumulative monthly imbalance volumes (difference between required receipt volume and actual receipt volumes), expressed as a percentage of required receipts of ten percent (10%) or less, shall be carried forward to the Aggregation Pool's storage inventory, net of storage U&UAF.

~~B.~~

B. Cumulative Imbalances Greater than 10%: Cumulative monthly imbalance volumes expressed as a percentage of required receipts, ~~which are~~of greater than 10% shall be treated as Cash Out Volumes, or may be carried forward to the Aggregation Pool's storage inventory~~.~~ at the discretion of Utility. In the event such imbalances are carried forward to storage inventory, written documentation shall be provided stating the reasons for such action. Cash Out Volumes may be ~~traded between Suppliers' Core Aggregation Pools,~~ purchased by the Utility from Supplier or sold by ~~the~~ Utility to ~~the~~ Supplier. If Utility declares the imbalance as ~~follows:~~subject to Cash Out, it must notify Supplier via email of the specific Cash Out Volume.

~~1. Core Aggregators interested in trading Cash Out Volumes shall provide written notice to the Utility requesting placement on the Cash Out Volume trading list. This notice shall remain in effect until changed by~~If Supplier~~.~~

~~2. By the 10th day of the month, the Utility shall provide a Cash Out Volume trading list, identifying the Core Aggregator, naming its trading contact, and specifying positive or negative imbalance status (excluding volumes) to all Core Aggregators with Cash Out Volumes from the preceding month.~~

~~3. Core Aggregators agreeing to trade Cash Out Volumes shall both provide written notice to the Utility, stating the applicable volume to be traded and counterparty Core Aggregator. Such written notice shall be deemed to be the Supplier's approval to allow the Utility to make the Cash Out Volume trade on Supplier's behalf.~~

~~4. All contractual arrangements, exchange or consideration, documentation, and cash out pricing shall be the responsibility of the trading Suppliers.~~

~~5.~~C. ~~If, by the last day of the month in which Core Aggregator receives notice of a Cash Out Volume, the Utility does not receive corresponding written notices from trading Suppliers which document the Cash Out Volume trade, or if Supplier's trade~~ does not eliminate the ~~Supplier's~~ total Cash Out Volume~~,~~ by the last day of the month in which Supplier receives notice of the Cash Out Volume ~~shall~~, the Cash Out Volume will be treated in the following manner:

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

a. Positive Cash Out Volumes: Utility shall purchase positive Cash Out Volumes from Core Aggregator at the lowest weighted average daily price*, as defined below, during the month the Cash Out Volume was created.

b. Negative Cash Out Volumes: Utility shall sell negative Cash Out Volumes to Core Aggregator at the highest weighted average daily price*, as defined below, plus $0.20/Dekatherm, during the month the Cash Out Volume was created.

* The weighted average daily price shall be that USD price per dekatherm reported in the Canadian ~~Natural~~ Gas ~~Daily Outlook under~~ "Price Reporter for the AECo/NIT ~~Energy Exchange Inc. (EEI) same day trading." This price will be converted to a price per Dekatherm in U.S. dollars by multiplying the price per gigajoule by 1.054615 and converting from Canadian to U.S. funds using the exchange rate reported in Canadian natural Gas Daily Outlook~~pricing point for the applicable day~~.~~(s).

c. Cash Out Accounting: A statement documenting the disposition of any Cash Out Volume shall be included with Core Aggregator's monthly statement for the month following the month in which the Cash Out Volume was created.

15.3 Receipt Nomination Balancing:

A. Supplier shall be responsible for monitoring, adjusting and assuring that daily receipts match nominations as set by ~~the~~ Utility and submitted by ~~the~~ Supplier for each Aggregated Pool. To the extent actual receipts are not within ten percent (10%) of the nominations calculated by ~~the~~ Utility, Supplier shall be given 48 hours to correct the imbalance during normal operating conditions. If Supplier fails to correct the imbalance, daily penalties may be assessed as set forth in Section ~~16~~15.6, and/or Supplier may be subject to the termination ~~provision~~provisions as set forth in Section ~~12.4~~11.1.

B. If Supplier consistently fails to comply with this provision, Utility shall report such failure to perform to the Commission.

C. During periods of Critical Operating Times, Supplier shall be required to correct negative imbalances greater than 2%. If Supplier does not correct such imbalance, daily- balancing penalties may be assessed as set forth in section ~~16~~15.6.

15.4 Storage Balancing: Each year, each Aggregation Pool shall be assigned storage level targets for September 1, November 1, and February 1. Utility shall monitor storage inventories of each Aggregation Pool and adjust receipt nomination calculations accordingly.

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15.5 Imbalances During Extreme Operating Conditions: The restricted operating conditions which ~~the~~ Utility is authorized to impose in accordance with this provision shall be applicable during any period in which Utility declares a Constrained Operating Time or a Critical Operating Time as defined in this section. Utility may declare restricted operating conditions during periods of Extreme Operating Conditions as follows:

~~a.~~A. Constrained Operating Time: A Constrained Operating Time may be declared when, in Utility's sole judgment, general system flexibility cannot be afforded to Suppliers to accommodate minor daily imbalances.

~~b.~~ B Critical Operating Time: ~~A~~Utility may declare a Critical Operating Time ~~may be declared in Utility's sole judgment~~:

1. When the total physical deliveries from all, or a portion of, the system are approaching, or expected to approach, a level that is in excess of the total physical receipts and the maximum volumes of gas available to be withdrawn from ~~the~~ Utility's storage facility without jeopardizing the integrity ~~of the~~ Utility's storage facility; or

2. When system pressures on one or more pipeline segments are falling and approaching a level, or are expected to fall and approach a level, that is at or below the minimum level Utility considers necessary for system integrity.

C. Notice: Utility ~~shall~~will notify ~~Suppliers~~Shippers at least 20 hours prior to the start of a gas day in which an ~~Extreme Operating Condition~~extreme operating condition is declared ~~(no later than noon of the preceding day). The start of a gas day shall be~~. For example, Utility must give notice by 12:00 p.m. for an extreme operating condition to be effective at 8:00 a.m. ~~mountain time.~~on the following day. Utility may declare a Critical Operating Time during the weekend only when a Constrained Operating Time was in effect on ~~the~~ Friday ~~immediately preceding such weekend~~. The only exception to the ~~notification~~ requirements ~~set forth herein~~to notify Shippers within the time frames noted is in the event of an unanticipated system emergency. ~~If such an emergency occurs,~~ Utility shall provide the reasons for the extreme operating conditions ~~and the action required by~~ to all ~~Suppliers~~shippers via telephone~~, facsimile~~ and/or ~~other electronic means.~~email. Extreme ~~Operating Conditions~~operating conditions shall be effective at the start of the ~~gas~~ day and continue day to day thereafter~~,~~ until Utility notifies ~~Suppliers~~Shippers that the ~~Extreme Operating Condition~~extreme operating condition no longer exists.

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

15.6 Imposition of Daily Balancing Penalties:

A. ~~Normal Operating Times: Suppliers with daily imbalances (positive or negative) greater than 10% of actual nominations may be charged the Balancing Penalty Rate set forth on the applicable rate schedule for all imbalance volumes greater than 10% of actual nominations. Payment of a penalty pursuant to this section shall under no circumstances be considered as providing any Supplier the right to take imbalance volumes. Supplier's payment of a penalty does not eliminate the imbalance.~~

~~B.~~ Constrained Operating Times: -Daily- balancing penalties ~~may~~shall not be imposed during Constrained Operating Times~~, as set forth in Section 16.6 A. above.~~.

~~C.~~ B. Critical Operating Times: Daily balancing penalties shall be imposed during Critical Operating Times as follows:

1. Negative Daily Imbalances: Suppliers with negative daily imbalances greater than 2% of actual nominations shall be charged the Balancing Penalty Rate set forth on the applicable rate schedule for all imbalance volumes greater than 2% of actual nominations.

   Payment of a penalty pursuant to this section shall under no circumstances be considered as providing any Supplier the right to take imbalance volumes. Supplier's payment of a penalty does not eliminate the imbalance. At the conclusion of the month, Supplier's imbalance shall continue to be subject to the provisions of ~~16~~15.2 with respect to any such monthly imbalances.

2. Positive Daily Imbalances: Suppliers with positive daily imbalances greater than 2% of actual nominations shall receive a ~~prorata~~pro rata share of any balancing penalty funds received from Suppliers with negative daily imbalances during the same period. In no event shall the penalty funds paid to ~~the~~ Supplier exceed the value of the imbalance above 2% multiplied by the Balancing Penalty Rate. Any daily imbalance volumes that result in Supplier receiving imbalance penalty funds shall be cleared from Supplier's account.

~~D.~~ C. Points of Receipt: Utility shall specify, in the notice of Critical Operating Time, Point(s) of Receipt that are eligible to receive balancing penalty funds. A confirmed nomination shall be allocated to Supplier's accounts at Point(s) of Receipt where an ~~operational balancing agreement~~Operational Balancing Agreement (OBA) exists between ~~the~~ Utility and the upstream Party. The volumes allocated to Suppliers' accounts at Point(s) of Receipt

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without an ~~operational balancing agreement~~OBA shall be based on actual flow. Negative imbalance penalties shall be based on actual flow at Point(s) of Receipt without an ~~operational balancing agreement~~OBA, even though actual flow information may not be known until after the Critical Operating Time. Supplier shall be responsible for coordinating and monitoring the gas flow information, as necessary, to avoid a negative imbalance. Utility is under no obligation to enter into ~~operational balancing agreements.~~OBAs. During Critical Operating Times, Utility shall ~~fax~~email a notice to Suppliers, documenting confirmed nominations at Point(s) of Receipt with ~~operational balancing agreements~~OBAs, within 4 hours of confirming nominations with the upstream party.

15.7 Imbalances With Other Parties: Utility shall not be responsible for eliminating any imbalances between Supplier and any third party.

15.8 Balancing Upon Termination: Upon termination of the Agreement, any existing cumulative imbalance shall be eliminated by the delivery of gas at the earliest practicable date, not to exceed 30 days following such termination. If at the end of the 30-day period an imbalance exists, the imbalance will be resolved in accordance with the Cash Out Volume procedure set forth in Section 15.2.

15.9 Merchant Function Exclusion: The Merchant of the regulated core supply shall not be subject to the Core Aggregation provisions of this Section.

16. STORAGE:

16.1 Storage Inventory Requirements: Each year, for each Aggregation Pool, Supplier shall be required to have in storage the following percentages of their full Storage Capacity requirements: on September 1, 75% of full requirements; on November 1, 100% of full requirements; and on February 1, 30% of full requirements. If Supplier fails to meet the storage capacity requirements set forth herein, Utility at its discretion may apply the Cash Out provision ~~shall apply~~ to volumes below the storage targets and volumes above 100% of the Allocated Storage Capacity. The applicable Cash Out price shall be determined from the target date to the immediately preceding target date. For example, the lowest and the highest prices from February 1 through September 1 shall apply to September 1 ~~cash out~~Cash Out transactions ~~as set out in Section 16~~.

16.2 Allocation of Capacity and Deliverability: ~~For as long as storage remains a required service under the Utility's gas transition plan to full customer choice,~~ Utility shall allocate, and Supplier shall accept, a portion of storage capacity and storage deliverability for each

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Aggregation Pool based on the estimated annual load of such Aggregation Pool. Allocations are Customer specific, and shall follow Customer if Customer changes Suppliers.

A. Storage Deliverability Allocation: Storage Deliverability shall be equal to 57.17% of Customer's allocated Transmission Capacity.

B. Storage Capacity Allocation: Storage Capacity shall be equal to ~~32~~74 days of Storage Deliverability.

16.3 Merchant Function Exclusion: The Merchant of the regulated core supply shall not be subject to the Core Aggregation provisions of this Section.

17. SERVICE AGREEMENT:

17.1 Firm Receipt Capacity: Aggregator shall be required to designate Primary Point(s) of Receipt equal to the Aggregation Pool's transmission MDDQ, plus U&UAF, less Storage MDDQ. The firmness of such gas supplies shall be reviewed by the Commission upon complaint.

17.2 Forms: Supplier shall enter into a contract with ~~the~~ Utility utilizing Utility's appropriate standard form of Core Aggregation Transportation Service Agreement (Agreement).

17.3 Term: The term of the Agreement shall be agreed upon between Supplier and Utility at the time of the execution thereof.

17.4 Miscellaneous: Utility reserves the right to tailor Agreements to individual needs of Supplier and Utility at the time of the Agreement; however, any specific Agreement requirements shall not unduly discriminate against or unnecessarily restrict access to any Supplier.

17.5 Modification: Subject to Commission approval, Utility shall have the right at any time and from time-_to-_time to amend, modify or cancel any and all of the provisions of this Rate Schedule without liability to or consent from any Supplier.

17.6 Further Conditions: Transportation and storage service shall be subject to such further conditions as are contained in the Agreement.

17.7 Customer Elections: ~~During the transition period, Customers~~ Customer shall give Utility written notice 45 days prior to returning to ~~core sales~~Core Sales service. Customer can return to Core Sales service only after receipt of a minimum of 12 months of Core Aggregation service and must stay on that service for a minimum of 12 months before returning to Core Aggregation

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service. If Customer elects to switch Suppliers, notice shall be given to the Utility 5- days prior to Customer's billing date, for the switch to be effective for Customer's next billing period.

17.8 Merchant Function Exclusion: The Merchant of the regulated core supply shall not be subject to the Core Aggregation provisions of this Section.

18. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY:

18.1 Priority 1 - Firm Transportation and Storage Service: Utility shall supply service first to its firm Suppliers, firm transportation and firm sales customers. If full service cannot be provided, Utility shall provide service on a ~~prorata~~pro rata basis according to ~~the~~ Supplier's MDDQ as specified in ~~the~~ Supplier's executed Agreement. Firm transportation and storage services and firm Suppliers shall be treated on a ~~prorata~~pro rata basis with firm sales service for purposes of allocating available capacity, except that Utility shall have the right to deviate from this procedure when, in its sole discretion, it is necessary to do so to mitigate threats to the public health and safety.

18.2 Allocation of Capacity: If the demand for new firm capacity, which includes but is not limited to receipt point capacity, transmission capacity, distribution capacity, and storage deliverability and capacity, is greater than the available capacity, the available capacity shall be allocated on a ~~prorata~~pro rata basis between firm ~~transportation~~Transportation, firm Aggregators and firm ~~sales service~~Sales Service. The applicable firm MDDQ shall be used for allocating receipt point capacity, transmission capacity, distribution capacity, storage capacity and storage deliverability. For purposes of establishing the firm sales MDDQ to be used in the allocation, the most recent approved filing before the Commission that sets forth the necessary information shall be utilized. Existing firm capacity and deliverability under active Core Aggregation, ~~transportation~~Transportation and ~~storage~~Storage service agreements shall not be affected by this provision.

18.3 ~~18.3~~ Miscellaneous: ~~Supplier~~

A. Shipper and Utility shall collaborate in making receipt and delivery adjustments, if possible, which may be necessary to protect life, health and safety.

B. Upon expiration of the Agreement, Shipper's Service Date will terminate.

19. STANDARDS OF CONDUCT:

~~The~~ Utility shall comply with the Standards of Conduct set forth in Rate Schedule No. GTC-1.

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

20. MISCELLANEOUS PROVISION:

20.1 Requests for Services: Requests for Core Aggregation Transportation Service shall be submitted, in writing, and shall provide the required information utilizing the ~~Transportation Authorization~~Customer Enrollment Form. The Merchant Function shall not be required to meet the requirements of this Section.

20.2 Creditworthiness: Utility shall not be required to perform or to continue service on behalf of any Supplier who is or ~~has~~may become insolvent or ~~who, at Utility's request, fails within a reasonable period to demonstrate~~has not demonstrated creditworthiness by providing ~~at least two (2) of~~ the ~~items listed below:~~following information:

A. Audited financial statements of Supplier or its guarantor for the two (2) most recent preceding years that show ~~good~~acceptable financial strength as determined by Utility in its sole discretion.

B. ~~A~~ Current Senior unsecured long-term ~~bond or commercial paper rating~~ ratings from Standard and Poor's or Moody's ~~equivalent to a "Ba" or better~~ratings agencies.

~~C. An estimated financial strength rating by Dun and Bradstreet sufficient to cover the credit to be extended and a corresponding Dun and Bradstreet composite credit appraisal of "fair" or better.~~

C. ~~A demonstration by Supplier that it~~Such other documentation as Utility shall reasonably request in connection with the service being requested.

~~D.~~ If Utility has ~~sufficient financial capacity or backing to warrant an extension of credit. This demonstration could include proof of banking relationships sufficient to cover the Agreement, or a detailed listing of credit reference within the industry, exhibiting a good credit history.~~

~~E.~~D. determined Supplier is not creditworthy based on information provided above, Supplier may receive service if Supplier ~~prepays~~provides a cash deposit, letter of credit, or creditworthy guarantor for such service~~,~~ in an amount equal to the cost of performing the maximum level of service requested by Supplier for a four (4) month period~~, plus a deposit in an amount equal to Supplier's allocated working storage inventory gas priced at the AECO C plus NOVA~~.

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E. A Letter of Credit form must be acceptable to Utility and issued by a U.S. commercial bank or a foreign bank with a U.S. branch office. Such bank shall have a Moody's credit rating of at least "A3" and a Standard and Poor's credit rating of at least "A-".

F. Merchant Function Exclusion: The Merchant Function shall not be required to meet the requirements of this Section.

20.3 Waiver of Default: No waiver by either party of any default by the other in the performance of any provisions of an executed Agreement shall operate as a waiver of any continuing or future default, whether of a like or different character.

20.4 Assignability: An executed Agreement shall bind and inure to the respective successors and assigns of the parties, but no assignment shall release either party from such party's obligations without the written consent of the other party, which consent shall not be unreasonably withheld.

20.5 —Effect of Headings: The headings used throughout this Rate Schedule, Rate Schedules to which they apply and the executed Agreements are inserted for reference purposes only and are not to be considered or taken into account in construing the terms and provisions of any section nor to be deemed in any way to qualify, modify or explain the effects of any such terms or provisions.

20.6 Further Conditions: Transportation and storage services shall be subject to such further conditions as are contained in the Agreement.

20.7 Miscellaneous:

A. Utility shall not be required to perform or continue service on behalf of any Supplier that fails to comply with the terms contained in this Rate Schedule.

B. Aggregator shall not be entitled to receive service if Aggregator is not current in its payments to ~~the Utility~~NorthWestern Energy for natural gas or electric ~~Utility~~utility service, or any charge, rate or fee authorized by the Commission for authorized services; provided, however, if the amount not current pertains to a bona fide dispute, including, but not limited to, force majeure claims relating to transportation or storage of gas, Aggregator shall be entitled to receive or continue to receive service if Aggregator posts a bond satisfactory to ~~the~~ Utility to cover the payment due ~~the~~ Utility.

C. If any penalty, that would otherwise be applicable under these provisions, is a direct consequence of any action or failure to take action by ~~the~~ Utility, or the failure of any

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

D. facility under ~~the~~ Utility's control, or an event of force majeure as defined in this Rate Schedule, said penalty shall not apply.

E. Supplier warrants that it will not take any actions that would subject Utility to the jurisdiction of FERC, the Department of Energy ~~(DOE)~~ or any successor government agency; provided, however, that service in accordance with Utility's Order 63 certificate will not be considered a breach of this warranty.

SERVICE AND RATES SUBJECT TO COMMISSION JURISDICTION: All rates and service conditions under this Rate Schedule are governed by the rules and regulations of the Public Service Commission of Montana and are subject to revision as the Commission may duly authorize in the exercise of its jurisdiction.

NorthWestern Energy NATURAL GAS TARIFF

	1st	Revised	Sheet No.	96.1
Canceling	Original	Revised	Sheet No.	96.1

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

Section	Description
1	Definitions
2	Quality of Gas
3	Pressure
4	Metering and Tests
5	Installations
6	Billing
7	Notice of Changes in Operating Conditions
8	Force Majeure
9	Warranties
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13	Taxes
14	Transmission Allocation
15	Nominations and Market and Supply Balancing
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17	Service Agreement
18	Priority of Service and Allocation of Capacity
19	Standards of Conduct
20	Miscellaneous Provisions

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Schedule No. AGTC-1

AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

1. DEFINITIONS: The following terms and abbreviations, when used in these General Terms and Operating Conditions (Rate Schedule No. AGTC-1), the Rate Schedules, and the Service Agreements (Agreements), shall have the following meaning:

1.1 "Aggregation Pool" shall mean the customer group aggregated to meet the requirements of the Core Aggregation Gas Transportation Program.

1.2 "BTU" shall mean British Thermal Unit.

1.3 "Core Aggregator" shall mean the Montana Public Service Commission (Commission) licensed party (Aggregator or Supplier) on whose behalf Utility provides core aggregation services.

1.4 "Cubic foot of gas" shall mean that quantity of gas, which, at a temperature of 60° Fahrenheit and at pressure of 14.9 pounds per square inch absolute, occupies 1 cubic foot.

1.5 "Day" shall mean a period of 24 consecutive hours, beginning and ending at 8:00 a.m. Mountain Time.

1.6 "Dekatherm" shall mean 1,000,000 BTUs.

1.7 "Gas" shall mean natural gas of the quality specified in Section 2 hereof.

1.8 "Gross heating value" shall mean the number of BTUs in a cubic foot of gas as calculated from a gas analysis obtained by gas chromatography. The heating value shall be calculated by summation of the heating values determined by GPA standard 2145. The heating value shall be calculated on a dry basis at a temperature of 60 degrees Fahrenheit and a pressure of 14.9 pounds per square inch absolute.

1.9 "Load Profiling" shall mean a process that utilizes typical customer load shapes to estimate the supply needs of customers without telemetering.

1.10 "Maximum Daily Delivery Quantity (MDDQ)" shall mean the maximum quantity of gas, after adjustments for compressor station fuel and line losses and other unaccounted for gas, if applicable, which Utility shall deliver to Supplier, or for Supplier's account, at the Point(s) of Delivery on any day.

1.11 "Maximum Daily Receipt Quantity (MDRQ)" shall be the MDDQ that Utility has contracted to receive at the Point(s) of Receipt on behalf of Supplier, including the compressor station fuel, line losses and other unaccounted for gas for any particular day.

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

1.12 "MCF" shall mean 1,000 cubic feet of gas and shall be measured as set forth in Section 4 hereof.

1.13 "Merchant Function" shall mean NorthWestern Energy, which purchases gas on behalf of the Utility's core customers.

1.14 "Month" shall mean a period extending from the beginning of the first day in a calendar month to the beginning of the first day in the next succeeding calendar month.

1.15 "Point(s) of Delivery" shall mean point(s) where Utility delivers gas for the account of Supplier.

1.16 "Point(s) of Receipt" shall mean point(s) where Utility receives gas for the account of Supplier.

1.17 "Primary Point(s) of Receipt" shall mean those point(s) designated as Primary in the Service Agreement where Supplier is entitled to firm service.

1.18 "Psia" shall mean pounds per square inch absolute.

1.19 "Psig" shall mean pounds per square inch gauge.

1.20 "Secondary Point(s) of Receipt" shall mean points other than Primary Point(s) of Receipt where Utility receives gas for the account of Supplier for transportation under a Service Agreement.

1.21 "Supplier" shall mean the Commission licensed party (Aggregator or Supplier) on whose behalf Utility provides core aggregation services.

1.22 "Therm" shall mean 100,000 Btus. 10 therms is equivalent to one dekatherm.

1.23 "Used and Unaccounted For" (U&UAF) shall mean volumes associated with standard operating procedures in the delivery of gas.

1.24 "Utility" shall mean NorthWestern Energy.

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

QUALITY OF GAS:

2.1 General Standards: Gas delivered to Utility shall be merchantable natural gas, at all times complying with the following quality requirements:

A. Gas shall be in its natural state as produced, including all hydrocarbon constituents therein contained except liquid or liquefiable hydrocarbons removed by Supplier. Supplier shall also have the right to remove nonhydrocarbon constituents. Supplier may enrich the gas to the extent required to meet the gross heating requirement set forth in paragraph "B" below, and may subject the gas, or permit the gas to be subjected, to compression, cooling, cleaning, dehydration and other processes. If Supplier is transferring gas to Utility transmission line directly, provisions must be made by Supplier to odorize the gas to the requirements set forth in the Department of Transportation publication CFR Title 49 Part 192.625.

B. The gross heating value of gas delivered to Utility shall not be less than 900 BTUs per cubic foot, and shall not be more than 1,200 BTUs per cubic foot. Utility may reject receipt of gas having a gross heating value of less than 900 BTUs per cubic foot or more than 1,200 BTUs per cubic foot. Acceptance of gas not meeting this gross heating value requirement shall not constitute a waiver of Utility's right to reject receipt of nonconforming gas.

C. Gas shall be merchantable and usable by the ultimate consumers without further treatment. In particular, the gas received by Utility hereunder at the Point(s) of Receipt shall be commercially free of dust, gum, gum-forming constituents, gasoline, other objectionable substances, and other solid or liquid matter that may become separated from the gas during transportation or storage and shall conform to the following specifications:

1.	Dust, rust or other solids	None
2.	Carbon dioxide	Not more than 2% by volume
3.	Oxygen	Not more than 10 parts per million or .001% by volume
4.	Hydrogen sulfide	Not more than 1/4 grain per 100 cubic feet
5.	Total sulfur	Not more than 2.0 grains per 100 cubic feet

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

6.	Temperature	Not more than 120° Fahrenheit.
7.	Water vapor	Not more than 4 pounds of water vapor per 1,000,000 cubic feet of gas
8.	Hydrocarbons	None liquefiable at temperatures in excess of 15 (Fahrenheit at pressures up to 1,200 psig.
9.	Nitrogen	Not more than 15% by volume

D. Unless otherwise agreed, Utility shall not be required to receive at any Point of Receipt gas that is of a quality inferior to that required by a third party at any Point of Delivery.

2.2 Utility's Option to Treat: Utility, at its option, may refuse to accept delivery of any gas not meeting the quality specifications set out in this Section. Thereafter, Supplier shall have the right to conform the gas to the above specifications. If Supplier does not elect to conform the gas to the specifications, then Utility may, at its option, accept gas tendered by Supplier which does not meet the specifications above, treat the gas to conform it to the specifications and charge Supplier for the actual cost of such treating, including, but not limited to, capital costs, O&M, fuel and shrinkage. Any Supplier tendering non specification gas shall indemnify Utility for any injury, damage, loss or liability caused by the delivery of such gas, except to the extent Utility knowingly and willingly accepts such non specification gas.

2.3 Hydrogen Sulfide: At Utility's sole discretion, Utility may install, at Supplier's expense, a properly operating hydrogen sulfide monitoring device (H2S monitor) that is capable of curtailing any deliveries to Utility of gas containing hydrogen sulfide in excess of 1/4 grain per 100 cubic feet (4 ppm).

PRESSURE:

3.1 Pressure at the Point(s) of Receipt: Supplier shall cause the gas to be tendered at the Point(s) of Receipt at a pressure sufficient to enter Utility's system, provided Supplier shall not, except with the agreement of Utility, be permitted to tender the gas at any Point of Receipt at a pressure in excess of the pressure specified for that Point of Receipt as set forth in the Agreement. If Supplier can supply gas at a higher pressure than the design of the pipeline system, Utility shall install, as a part of the equipment required under Section 4.3 below, pressure limiting devices to ensure the maximum allowable operating pressure (MAOP) of the pipeline shall not be exceeded.

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

3.2 Pressure at the Point(s) of Delivery: Utility shall cause the gas to be delivered at the Point(s) of Delivery at such pressures sufficient to effect delivery into the receiving facilities against the pressures prevailing from time to time.

4. METERING AND TESTS:

Metering and testing shall be in accordance with Utility's Natural Gas Service Rules and Regulations Rule Nos. 9 and 11.

5. INSTALLATIONS:

Installations shall be in accordance with Utility's Natural Gas Service Rules and Regulations Rule Nos. 7 and 8.

6. BILLING:

6.1 If information necessary for billing by Utility is in the possession of Supplier, Supplier shall furnish such information 5 business days before the billing date for each Customer.

6.2 If Utility bills for Supplier's commodity, Supplier shall enter into a separate contract for billing services, and shall be billed in accordance with Rate Schedule No. GBS-1.

6.3 Customer billing shall be in accordance with the Natural Gas Utility's Service Rules and Regulations Rule No. 10.

7. NOTICE OF CHANGES IN OPERATING CONDITIONS:

Utility and Supplier shall assure that each other shall be notified from time to time, as necessary, of expected changes in the rates of delivery or receipt of gas, or in the pressures or other operating conditions, as stipulated to in the Agreement, and the reason for such expected changes, so that they may be accommodated when they occur.

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

8. FORCE MAJEURE:

8.1 Notice: A party's obligation to perform shall be suspended in whole or in part: (1) if an event of force majeure occurs; and (2) the affected party provides written notice describing the event to the other as soon as reasonably possible after the event occurs. The affected party shall resume performance when conditions reasonably allow. The affected party shall not be required to make-up performance lost during the force majeure event.

8.2 Definition: The term "force majeure" shall mean acts of god, governmental action, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, hurricanes, tornadoes, storms, storm warnings, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accidents to machinery or lines of pipe, the necessity for making repairs to or alterations of machinery or lines of pipe, freezing of wells or lines of pipe, partial or entire failure of wells or sources of supply of gas, and any other causes, whether of the kind enumerated or otherwise, not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome. This term shall also include: (a) those instances where either party hereto is required to obtain servitudes, rights-of-way grants, permits or licenses to enable such party to fulfill its obligations, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such servitudes, rights-of-way grants, permits or licenses; and (b) those instances where either party hereto is required to furnish materials and supplies for the purpose of constructing or maintaining facilities or is required to secure permits or permissions from any governmental agency to enable such party to fulfill its obligations hereunder, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such materials and supplies, permits and permissions.

8.3 Strikes: The settlement of strikes or lockouts shall be within the discretion of the party having the difficulty, and that the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of any opposing party when such course is inadvisable in the discretion of the party having the difficulty.

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

9. WARRANTIES:

9.1 Eligibility:

A. Any Supplier transporting or storing gas on Utility's system warrants for itself, its successors and assigns that all gas delivered to Utility for service shall be eligible for the requested service under applicable rules, regulations or orders of the appropriate regulatory authority.

B. Supplier shall indemnify Utility and save it harmless from all demands, suits, actions, judgments, damages, costs, losses, expenses (including reasonable attorney fees incurred enforcing this indemnity obligation or defending a third party claim) and regulatory proceedings, arising from breach of these representations and warranties.

9.2 Title: Supplier warrants title to all gas delivered by it to Utility. Supplier and Utility warrant that each has the right to deliver and redeliver the gas, and that such gas is free from liens and adverse claims of every kind. Supplier shall indemnify and save Utility harmless against all loss, damage, claims and expense of every character with respect to gas delivered by it on account of royalties, taxes, payments, liens or other charges arising before or created upon delivery of the gas.

9.3 Firm Delivery: Supplier represents that gas supplies necessary to cover the maximum firm peak day requirement as represented by the total MDDQ plus U&UAF in the Agreement shall be supplied on a firm basis. The firmness of such gas supplies shall be reviewed by the Commission upon complaint.

10. RESPONSIBILITY FOR GAS:

Utility shall be deemed to be responsible for all gas from the time that such gas is received by it at the Point(s) of Receipt to the time that it is delivered at the Point(s) of Delivery. Utility's responsibility with respect to Supplier's gas shall be deemed to be met if Utility exercises ordinary care in protecting such gas.

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

11. TERMINATION:

11.1 Termination of Agreement:

A. Utility's obligation to provide, and Supplier's contractual right to receive, service shall terminate on the earlier of: (a) the date provided in the applicable Agreement for the termination of service: or (b) the date on which Utility determines, on a nondiscriminatory, basis to cease transporting gas.

B. The Agreement between an Aggregator and Utility can be terminated if Aggregator fails to issue payment to Utility within seven (7) days of issuance of a past due notice, or if Utility receives any notification that Aggregator has filed or will be filing any type of bankruptcy, or closing its business.

C. Further, the Agreement may be terminated or renegotiated as to the applicable terms at any time by Aggregator or Utility, each in their sole discretion, if the Commission or the Federal Energy Regulatory Commission (FERC), whichever is applicable, determines that the rates or fees per dekatherm as provided in the Agreement are not in accordance with the Commission's or the FERC's regulations or governing statutes, or are not fair and equitable to all parties. Utility reserves the further right to unilaterally terminate or temporarily suspend service if Utility, in the reasonable exercise of its sole discretion, determines that such service is injurious to the physical operation of any Utility facilities or if Aggregator does not comply with any provisions contained in this Rate Schedule or Agreement. Aggregator shall not be entitled to transportation service under the Agreement or otherwise, subsequent to the effective date of any termination hereunder.

11.2 Commission Action: Agreement may be terminated or renegotiated as to the applicable terms at any time by Supplier or Utility, each in their sole discretion, if the Commission or the FERC, whichever is applicable, determines that the rates or fees per dekatherm as provided in the Agreement are not in accordance with the Commission's or the FERC's regulations or governing statutes, or are not fair and equitable to all parties.

11.3 Non-Performance: Utility may terminate the Agreement if Supplier is charged balancing penalties for failure to meet the daily confirmed nominations imposed by Utility 3 times in the first year of the Agreement, or 5 times during the life of the Agreement, or if Supplier does not comply with any provisions contained in this Rate Schedule, the Agreement, or Commission licensing provisions.

11.4 Termination of Customer Enrollment Form:

A. The Customer Enrollment Form shall remain in effect unless any of the following occurs:

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

1. After initial contract term, any party provides 30-day advance written notice of cancellation to Utility and/or the other parties;
2. Any party goes out of business;
3. Customer is no longer receiving service at the meter location;
4. Aggregator cancels service to Customer for Customer's failure to pay for service provided by Aggregator under the Program by sending written notice of cancellation to Utility and Customer;
5. Utility cancels service to Aggregator for Aggregator's failure to pay for service provided by Utility or for other breach of Contract by sending written notice of cancellation to Aggregator and Customer, pursuant to Section 8. D. below;
6. Aggregator, Customer or Utility files for or is forced into bankruptcy proceedings; or
7. Change in Utility's tariff rate schedules that materially affect the rights of the parties.

B. Customer shall have 45 days from the date of the cancellation notice by Aggregator in which to join another Aggregation Pool or return to Utility's Distribution Services Division. If the Agreement between Aggregator and Utility is canceled and Customer continues to receive service at its meter location, Customer shall be served by Utility's Distribution Services Division and billed in accordance with the tariffs currently being exercised to supply other Customers of such Division, until Customer elects another Aggregator.

C. Customers shall remain responsible to Utility for any charges incurred by their Aggregator(s) associated with the Program prior to the effective date of service termination.

D. Supplier shall not be entitled to transportation service under the Agreement or otherwise, after the effective date of any termination.

12. LIABILITY OF PARTIES:

Utility and Supplier each assume full responsibility and liability for the maintenance and operation of its respective properties and equipment and shall indemnify and save harmless the other party from all liability and expense due to any and all damage, claims or actions, including injury or death of persons, arising from any act or accident in connection with installation, presence, maintenance and operation of the property and equipment of the indemnifying party save and except such damage, claim or action caused by the negligence of the party otherwise to be indemnified hereunder.

13. TAXES:

Supplier shall pay, or cause to be paid, all production (including ad valorem-type production taxes), gathering, delivery, sales, severance, or other excise taxes or assessments upon the gas delivered by

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

Supplier to Utility that are now or hereafter in existence or authorized for collection by any state or other governmental agency or duly constituted authority, either directly or indirectly. Supplier shall be responsible for all taxes imposed upon the transportation of the gas to be transported, and shall reimburse Utility for any such taxes incurred by or assessed to Utility.

14. TRANSMISSION CAPACITY ALLOCATION:

Utility shall allocate, and Supplier shall accept, a portion of Transmission Capacity for each Aggregation Pool based on the estimated annual load of such Aggregation Pool. Allocations are Customer specific, and shall follow Customer if Customer changes Suppliers. Transmission Capacity shall be equal to 1.01% of the Estimated Annual Load of the Aggregation Pool. In circumstances where actual data and/or load information exist, Utility, Customer, or Supplier may present such evidence and propose to change the Transmission Capacity Allocation for a specific pool. Utility, in its sole discretion, shall determine if a change in the Transmission Capacity Allocation is warranted.

15. NOMINATIONS AND MARKET AND SUPPLY BALANCING:

15.1 Nominations: Nominations for core aggregation receipts and deliveries are performed similarly to other nominations placed on Utility's transmission system.

A. Each week Utility shall provide month-to-date usage information that will be used to determine the appropriate nominations for balancing purposes.

B. At its discretion, Utility may modify receipt nominations to balance storage inventories, adjust for weather variations, or for other operational reasons. At no time shall the receipt nomination exceed the aggregated pool's MDDQ plus fuel U&UAF unless mutually agreed to by Utility and Supplier. During Critical Operating Times, the receipt nominations shall default to the aggregated pool's MDDQ plus any fuel reimbursement, less the aggregated pool's storage MDDQ.

15.2 Monthly Imbalances:

A. Cumulative monthly imbalance volumes (difference between required receipt volume and actual receipt volumes), expressed as a percentage of required receipts of ten percent (10%) or less, shall be carried forward to the Aggregation Pool's storage inventory, net of storage U&UAF.

B. Cumulative Imbalances Greater than 10%: Cumulative monthly imbalance volumes expressed as a percentage of required receipts, of greater than 10% shall be treated as Cash Out Volumes, or may be carried forward to the Aggregation Pool's storage inventory at the discretion of Utility. In the event such imbalances are carried forward to storage inventory,

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

written documentation shall be provided stating the reasons for such action. Cash Out Volumes may be purchased by the Utility from Supplier or sold by Utility to Supplier. If Utility declares the imbalance as subject to Cash Out, it must notify Supplier via email of the specific Cash Out Volume.

C. If Supplier does not eliminate the total Cash Out Volume by the last day of the month in which Supplier receives notice of the Cash Out Volume, the Cash Out Volume will be treated in the following manner:

a. Positive Cash Out Volumes: Utility shall purchase positive Cash Out Volumes from Core Aggregator at the lowest weighted average daily price*, as defined below, during the month the Cash Out Volume was created.

b. Negative Cash Out Volumes: Utility shall sell negative Cash Out Volumes to Core Aggregator at the highest weighted average daily price*, as defined below, plus $0.20/Dekatherm, during the month the Cash Out Volume was created.

* The weighted average daily price shall be that USD price per dekatherm reported in the Canadian Gas Price Reporter for the AECo/NIT pricing point for the applicable day(s).

c. Cash Out Accounting: A statement documenting the disposition of any Cash Out Volume shall be included with Core Aggregator's monthly statement for the month following the month in which the Cash Out Volume was created.

15.3 Receipt Nomination Balancing:

A. Supplier shall be responsible for monitoring, adjusting and assuring that daily receipts match nominations as set by Utility and submitted by Supplier for each Aggregated Pool. To the extent actual receipts are not within ten percent (10%) of the nominations calculated by Utility, Supplier shall be given 48 hours to correct the imbalance during normal operating conditions. If Supplier fails to correct the imbalance, daily penalties may be assessed as set forth in Section 15.6, and/or Supplier may be subject to the termination provisions as set forth in Section 11.1.

B. If Supplier consistently fails to comply with this provision, Utility shall report such failure to perform to the Commission.

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

C. During periods of Critical Operating Times, Supplier shall be required to correct negative imbalances greater than 2%. If Supplier does not correct such imbalance, daily balancing penalties may be assessed as set forth in section 15.6.

15.4 Storage Balancing: Each year, each Aggregation Pool shall be assigned storage level targets for September 1, November 1, and February 1. Utility shall monitor storage inventories of each Aggregation Pool and adjust receipt nomination calculations accordingly.

15.5 Imbalances During Extreme Operating Conditions: The restricted operating conditions which Utility is authorized to impose in accordance with this provision shall be applicable during any period in which Utility declares a Constrained Operating Time or a Critical Operating Time as defined in this section. Utility may declare restricted operating conditions during periods of Extreme Operating Conditions as follows:

A. Constrained Operating Time: A Constrained Operating Time may be declared when, in Utility's sole judgment, general system flexibility cannot be afforded to Suppliers to accommodate minor daily imbalances.

B Critical Operating Time: Utility may declare a Critical Operating Time:

1. When the total physical deliveries from all, or a portion of, the system are approaching, or expected to approach, a level that is in excess of the total physical receipts and the maximum volumes of gas available to be withdrawn from Utility's storage facility without jeopardizing the integrity of Utility's storage facility; or

2. When system pressures on one or more pipeline segments are falling and approaching a level, or are expected to fall and approach a level, that is at or below the minimum level Utility considers necessary for system integrity.

C. Notice: Utility will notify Shippers at least 20 hours prior to the start of a gas day in which an extreme operating condition is declared. For example, Utility must give notice by 12:00 p.m. for an extreme operating condition to be effective at 8:00 a.m. on the following day. Utility may declare a Critical Operating Time during the weekend only when a Constrained Operating Time was in effect on Friday. The only exception to the requirements to notify Shippers within the time frames noted is in the event of an unanticipated system emergency. Utility shall provide the reasons for the extreme operating conditions to all shippers via telephone and/or email. Extreme operating conditions shall be effective at the start of the day and continue day to day thereafter until Utility notifies Shippers that the extreme operating condition no longer exists.

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

15.6 Imposition of Daily Balancing Penalties:

A. Constrained Operating Times: Daily balancing penalties shall not be imposed during Constrained Operating Times.

B. Critical Operating Times: Daily balancing penalties shall be imposed during Critical Operating Times as follows:

1. Negative Daily Imbalances: Suppliers with negative daily imbalances greater than 2% of actual nominations shall be charged the Balancing Penalty Rate set forth on the applicable rate schedule for all imbalance volumes greater than 2% of actual nominations.

   Payment of a penalty pursuant to this section shall under no circumstances be considered as providing any Supplier the right to take imbalance volumes. Supplier's payment of a penalty does not eliminate the imbalance. At the conclusion of the month, Supplier's imbalance shall continue to be subject to the provisions of 15.2 with respect to any such monthly imbalances.

2. Positive Daily Imbalances: Suppliers with positive daily imbalances greater than 2% of actual nominations shall receive a pro rata share of any balancing penalty funds received from Suppliers with negative daily imbalances during the same period. In no event shall the penalty funds paid to Supplier exceed the value of the imbalance above 2% multiplied by the Balancing Penalty Rate. Any daily imbalance volumes that result in Supplier receiving imbalance penalty funds shall be cleared from Supplier's account.

C. Points of Receipt: Utility shall specify, in the notice of Critical Operating Time, Point(s) of Receipt that are eligible to receive balancing penalty funds. A confirmed nomination shall be allocated to Supplier's accounts at Point(s) of Receipt where an Operational Balancing Agreement (OBA) exists between Utility and the upstream Party. The volumes allocated to Suppliers' accounts at Point(s) of Receipt without an OBA shall be based on actual flow. Negative imbalance penalties shall be based on actual flow at Point(s) of Receipt without an OBA, even though actual flow information may not be known until after the Critical Operating Time. Supplier shall be responsible for coordinating and monitoring the gas flow information, as necessary, to avoid a negative imbalance. Utility is under no obligation to enter into OBAs. During Critical Operating Times, Utility shall email a notice to Suppliers, documenting confirmed nominations at Point(s) of Receipt with OBAs, within 4 hours of confirming nominations with the upstream party.

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AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

15.7 Imbalances With Other Parties: Utility shall not be responsible for eliminating any imbalances between Supplier and any third party.

15.8 Balancing Upon Termination: Upon termination of the Agreement, any existing cumulative imbalance shall be eliminated by the delivery of gas at the earliest practicable date, not to exceed 30 days following such termination. If at the end of the 30-day period an imbalance exists, the imbalance will be resolved in accordance with the Cash Out Volume procedure set forth in Section 15.2.

15.9 Merchant Function Exclusion: The Merchant of the regulated core supply shall not be subject to the Core Aggregation provisions of this Section.

16. STORAGE:

16.1 Storage Inventory Requirements: Each year, for each Aggregation Pool, Supplier shall be required to have in storage the following percentages of their full Storage Capacity requirements: on September 1, 75% of full requirements; on November 1, 100% of full requirements; and on February 1, 30% of full requirements. If Supplier fails to meet the storage capacity requirements set forth herein, Utility at its discretion may apply the Cash Out provision to volumes below the storage targets and volumes above 100% of the Allocated Storage Capacity. The applicable Cash Out price shall be determined from the target date to the immediately preceding target date. For example, the lowest and the highest prices from February 1 through September 1 shall apply to September 1 Cash Out transactions.

16.2 Allocation of Capacity and Deliverability: Utility shall allocate, and Supplier shall accept, a portion of storage capacity and storage deliverability for each Aggregation Pool based on the estimated annual load of such Aggregation Pool. Allocations are Customer specific, and shall follow Customer if Customer changes Suppliers.

A. Storage Deliverability Allocation: Storage Deliverability shall be equal to 57.17% of Customer's allocated Transmission Capacity.

B. Storage Capacity Allocation: Storage Capacity shall be equal to 74 days of Storage Deliverability.

16.3 Merchant Function Exclusion: The Merchant of the regulated core supply shall not be subject to the Core Aggregation provisions of this Section.

17. SERVICE AGREEMENT:

(continued)

Schedule No. AGTC-1

AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

17.1 Firm Receipt Capacity: Aggregator shall be required to designate Primary Point(s) of Receipt equal to the Aggregation Pool's transmission MDDQ, plus U&UAF, less Storage MDDQ. The firmness of such gas supplies shall be reviewed by the Commission upon complaint.

17.2 Forms: Supplier shall enter into a contract with Utility utilizing Utility's appropriate standard form of Core Aggregation Transportation Service Agreement (Agreement).

17.3 Term: The term of the Agreement shall be agreed upon between Supplier and Utility at the time of the execution thereof.

17.4 Miscellaneous: Utility reserves the right to tailor Agreements to individual needs of Supplier and Utility at the time of the Agreement; however, any specific Agreement requirements shall not unduly discriminate against or unnecessarily restrict access to any Supplier.

17.5 Modification: Subject to Commission approval, Utility shall have the right at any time and from time to time to amend, modify or cancel any and all of the provisions of this Rate Schedule without liability to or consent from any Supplier.

17.6 Further Conditions: Transportation and storage service shall be subject to such further conditions as are contained in the Agreement.

17.7 Customer Elections: Customer shall give Utility written notice 45 days prior to returning to Core Sales service. Customer can return to Core Sales service only after receipt of a minimum of 12 months of Core Aggregation service and must stay on that service for a minimum of 12 months before returning to Core Aggregation service. If Customer elects to switch Suppliers, notice shall be given to the Utility 5 days prior to Customer's billing date, for the switch to be effective for Customer's next billing period.

17.8 Merchant Function Exclusion: The Merchant of the regulated core supply shall not be subject to the Core Aggregation provisions of this Section.

18. PRIORITY OF SERVICE AND ALLOCATION OF CAPACITY:

18.1 Priority 1 - Firm Transportation and Storage Service: Utility shall supply service first to its firm Suppliers, firm transportation and firm sales customers. If full service cannot be provided, Utility shall provide service on a pro rata basis according to Supplier's MDDQ as specified in Supplier's executed Agreement. Firm transportation and storage services and firm Suppliers shall be treated on a pro rata basis with firm sales service for purposes of allocating available capacity, except that Utility shall have the right to deviate from this procedure when, in its sole discretion, it is necessary to do so to mitigate threats to the public health and safety.

(continued)

Schedule No. AGTC-1

AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

18.2 Allocation of Capacity: If the demand for new firm capacity, which includes but is not limited to receipt point capacity, transmission capacity, distribution capacity, and storage deliverability and capacity, is greater than the available capacity, the available capacity shall be allocated on a pro rata basis between firm Transportation, firm Aggregators and firm Sales Service. The applicable firm MDDQ shall be used for allocating receipt point capacity, transmission capacity, distribution capacity, storage capacity and storage deliverability. For purposes of establishing the firm sales MDDQ to be used in the allocation, the most recent approved filing before the Commission that sets forth the necessary information shall be utilized. Existing firm capacity and deliverability under active Core Aggregation, Transportation and Storage service agreements shall not be affected by this provision.

18.3 Miscellaneous:

A. Shipper and Utility shall collaborate in making receipt and delivery adjustments, if possible, which may be necessary to protect life, health and safety.

B. Upon expiration of the Agreement, Shipper's Service Date will terminate.

19. STANDARDS OF CONDUCT:

Utility shall comply with the Standards of Conduct set forth in Rate Schedule No. GTC-1.

20. MISCELLANEOUS PROVISION:

20.1 Requests for Services: Requests for Core Aggregation Transportation Service shall be submitted, in writing, and shall provide the required information utilizing the Customer Enrollment Form. The Merchant Function shall not be required to meet the requirements of this Section.

20.2 Creditworthiness: Utility shall not be required to perform or to continue service on behalf of any Supplier who is or may become insolvent or has not demonstrated creditworthiness by providing the following information:

A. Audited financial statements of Supplier or its guarantor for the two (2) most recent preceding years that show acceptable financial strength as determined by Utility in its sole discretion.

B. Current Senior unsecured long-term ratings from Standard and Poor's or Moody's ratings agencies.

(continued)

Schedule No. AGTC-1

AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

C. Such other documentation as Utility shall reasonably request in connection with the service being requested.

D. If Utility has determined Supplier is not creditworthy based on information provided above, Supplier may receive service if Supplier provides a cash deposit, letter of credit, or creditworthy guarantor for such service in an amount equal to the cost of performing the maximum level of service requested by Supplier for a four (4) month period.

E. A Letter of Credit form must be acceptable to Utility and issued by a U.S. commercial bank or a foreign bank with a U.S. branch office. Such bank shall have a Moody's credit rating of at least "A3" and a Standard and Poor's credit rating of at least "A-".

F. Merchant Function Exclusion: The Merchant Function shall not be required to meet the requirements of this Section.

20.3 Waiver of Default: No waiver by either party of any default by the other in the performance of any provisions of an executed Agreement shall operate as a waiver of any continuing or future default, whether of a like or different character.

20.4 Assignability: An executed Agreement shall bind and inure to the respective successors and assigns of the parties, but no assignment shall release either party from such party's obligations without the written consent of the other party, which consent shall not be unreasonably withheld.

20.5 Effect of Headings: The headings used throughout this Rate Schedule, Rate Schedules to which they apply and the executed Agreements are inserted for reference purposes only and are not to be considered or taken into account in construing the terms and provisions of any section nor to be deemed in any way to qualify, modify or explain the effects of any such terms or provisions.

20.6 Further Conditions: Transportation and storage services shall be subject to such further conditions as are contained in the Agreement.

20.7 Miscellaneous:

A. Utility shall not be required to perform or continue service on behalf of any Supplier that fails to comply with the terms contained in this Rate Schedule.

(continued)

Schedule No. AGTC-1

AGGREGATION GENERAL TERMS AND OPERATING CONDITIONS

B. Aggregator shall not be entitled to receive service if Aggregator is not current in its payments to NorthWestern Energy for natural gas or electric utility service, or any charge, rate or fee authorized by the Commission for authorized services; provided, however, if the amount not current pertains to a bona fide dispute, including, but not limited to, force majeure claims relating to transportation or storage of gas, Aggregator shall be entitled to receive or continue to receive service if Aggregator posts a bond satisfactory to Utility to cover the payment due Utility.

C. If any penalty, that would otherwise be applicable under these provisions, is a direct consequence of any action or failure to take action by Utility, or the failure of any facility under Utility's control, or an event of force majeure as defined in this Rate Schedule, said penalty shall not apply.

D. Supplier warrants that it will not take any actions that would subject Utility to the jurisdiction of FERC, the Department of Energy or any successor government agency; provided, however, that service in accordance with Utility's Order 63 certificate will not be considered a breach of this warranty.

SERVICE AND RATES SUBJECT TO COMMISSION JURISDICTION: All rates and service conditions under this Rate Schedule are governed by the rules and regulations of the Public Service Commission of Montana and are subject to revision as the Commission may duly authorize in the exercise of its jurisdiction.

STATE OF MONTANA
Department of Public Service Regulation
PUBLIC SERVICE COMMISSION

NATURAL GAS GENERAL FILING

LEAD-LAG STUDY

PREFILED DIRECT TESTIMONY OF
PAUL M. NORMAND
MANAGEMENT APPLICATIONS CONSULTING, INC.

ON BEHALF OF

NORTHWESTERN ENERGY

SEPTEMBER 30, 2016

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY OF

PAUL M. NORMAND

ON BEHALF OF NORTHWESTERN ENERGY

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LIST OF EXHIBITS

Exhibit	Description
Exhibit__(PMN-1)	Pro Forma Lead-Lag Summary
Exhibit__(PMN-2)	Qualifications of Paul M. Normand

1 **I. INTRODUCTION**

2 **Q. Please state your name, address and business affiliation.**

3 A. My name is Paul M. Normand. I am a Principal with the firm of Management
4 Applications Consulting, Inc. ("MAC"), 1103 Rocky Drive, Suite 201, Reading, PA
5 19609.

6 **Q. Please describe MAC.**

7 A. MAC is a management consulting firm that provides rate and regulatory assistance
8 including depreciation services for electric, gas and water utilities.

9 **Q. Please summarize your education and business experience.**

10 A. This information is contained in Exhibit__(PMN-2).

11 **II. PURPOSE OF TESTIMONY**

12 **Q. Please discuss the purpose of your testimony.**

13 A. Our consulting firm was retained by NorthWestern Energy ("NorthWestern" or "the
14 Company") to conduct a lead-lag study. The purpose of my direct testimony is to present
15 and sponsor the cash working capital ("CWC") net lag days for services associated with
16 the natural gas transmission, distribution, storage, and gas production assets (collectively
17 "gas services") included in this filing.

18 These net lag days are used to calculate the CWC requirement included in
19 NorthWestern's overall revenue requirements calculation by means of the CWC included
20 in rate base.

21 **Q. How is your testimony organized?**

1 A. My testimony consists of three sections. Section I is introductory information. Section II
2 describes the purpose and organization of my testimony. Section III presents results of
3 the lead-lag study MAC prepared on behalf of NorthWestern to determine the net lag
4 days for the gas services CWC calculation.

5 **III. CASH WORKING CAPITAL**

6 **Definition of CWC**

7 **Q. Please define CWC.**

8 A. CWC is the amount of stockholder-supplied capital required to fund the day-to-day
9 operations of a company. It accounts for the timing differences between when service is
10 provided to customers and revenues are received and when NorthWestern receives
11 services from vendors and when it pays for these services. CWC represents amounts
12 funded by investors to provide services prior to payment for such services by customers.
13 As such, CWC is typically an addition to a utility's rate base. In some instances, the
14 utility's operations can provide a source of cash which can be considered an offset to the
15 investor's cash required. In these instances, the total negative CWC can be ignored and
16 set to zero or considered as a reduction to rate base.

17 **Q. Did you perform analyses to calculate the net lag days of NorthWestern using**
18 **adjusted expenses for the test year?**

19 A. Yes. Exhibit__(PMN-1) summarizes the results of the lead-lag study conducted for
20 NorthWestern using actual revenues to calculate the revenue lag and preliminary pro
21 forma expenses to calculate the expense lags for the test year ending December 31, 2015.
22 As shown in this exhibit, the net lag for CWC for gas services operating expenses is -
23 65.21 days and -48.41 days for interest expense.

1 **Q. What is a lead-lag study?**

2 A. A lead-lag study is an analysis designed to determine the funding required to operate a
3 company on a day-to-day basis. A lead-lag study compares (1) the timing difference
4 between the receipt of service by customers and their subsequent payment for these same
5 services and (2) the timing difference between the incurrence of costs by a company and
6 its subsequent payment of these costs. Therefore, a lead-lag study must compute both a
7 revenue (lead) lag and an expense (lead) or lag. Exhibit__(PMN-1), page 1 summarizes
8 the lead-lag study results for NorthWestern. The revenues and expenses (lead) lag days
9 were developed using systematic reviews of cash flows for NorthWestern's actual
10 revenues and operating expenses. The lead-lag study we performed measured the net lag
11 days needed to calculate the CWC for the gas services operations for the 12-month
12 preliminary pro forma period ending December 31, 2015.

13 **Q. Please define the terms "lag days" and "lead days" as used in your testimony.**

14 A. Revenue lag is the number of days between delivery of service to NorthWestern's
15 customers and the subsequent receipt by NorthWestern of payment for the service
16 (revenue lag days). Expense lag is the number of days between the receipt of goods or
17 services provided to NorthWestern by vendors and the payment by NorthWestern for
18 those goods and services (expense lag days).

19 Because NorthWestern's gas customers receive service prior to paying for it,
20 NorthWestern experiences a revenue lag in its daily operating costs. This revenue lag is
21 computed based upon analyses of the time lag between the date when customers receive
22 service and the date when the customers pay for such service. The longer the revenue
23 lag, the greater the length of time that investor capital is required to fund the Company's

1 day-to-day operations. The revenue lag for NorthWestern is 43.88 days as developed in
2 Exhibit__(PMN-1), page 2, line 29.

3 Generally, expenses are paid by NorthWestern after vendors have provided their goods or
4 services, which results in an expense lag. On occasion, NorthWestern pays for services
5 before they are provided, such as prepayments. In these instances, the expenses lead their
6 service period. The expense lag is calculated as the number of days between the date
7 when NorthWestern receives goods or services from a vendor and the date when
8 NorthWestern pays for such goods or services. If the expenses are paid before the
9 services are provided, then the expense lag is expressed as a negative amount.
10 Consequently, any increase in the number of expense lag days results in a reduction of
11 the amount of working capital required for ongoing NorthWestern gas services
12 operations.

13 The arithmetic difference between the computed revenue lag and the computed expense
14 lag is the number of days used to calculate the CWC.

15 As shown on Exhibit__(PMN-1), page 1, line 36, NorthWestern's gas services net lag
16 days are -65.21 days for Operating Expense and -48.41 days for Interest Expense on line
17 42. The net lag days are negative for NorthWestern because the total of the expense lags
18 exceeds the total revenue lags. The revenue lag is 43.88 days, as shown in
19 Exhibit__(PMN-1), page 1, line 1, and the expense lags are 109.09 days for Operating
20 Expense as shown in Exhibit__(PMN-1), page 1, line 31 and 92.29 days for Interest
21 Expense as shown on line 41. The resulting net negative lag days result in negative CWC
22 which is a reduction to rate base.

1 **Q. Have you deviated from the methodology previously approved by the Montana**
2 **Public Service Commission ("MPSC") for calculating CWC?**
3 A. No. I have employed the methodology previously approved by the MPSC for calculating
4 NorthWestern's lag days to construct the 2015 gas services lead-lag study presented in
5 Exhibit__(PMN-1).

6 **Lead-Lag Study General Approach**

7 **Q. Has your firm conducted lead-lag studies for NorthWestern in the past?**
8 A. Yes. MAC was selected to perform a lead-lag study for NorthWestern's 2006
9 Informational Filing in Docket D2006.10.141 using calendar year 2005 data.
10 Subsequently, that lead-lag study was updated as part of preparation for NorthWestern's
11 filing in Docket No. D2007.7.82. MAC also performed a gas and electric delivery
12 function lead-lag study in Docket No. D2009.9.129. The lead-lag study included in this
13 filing is based on gas services for the 12 months ended December 31, 2015.

14 **Q. Are there any significant methodological differences between the earlier lead-lag**
15 **studies and the study you are filing now?**
16 A. No.

17 **Q. Please describe how the net lag days for NorthWestern were developed in this study.**
18 A. The net lag days computed for NorthWestern's gas services in Exhibit__(PMN-1)
19 utilized the same approach reviewed and subsequently approved by the MPSC for the
20 Montana Power Company in 1991. The lead-lag study systematically reviews cash flows
21 for NorthWestern beginning with revenues, then operating expenses and finally considers

1 cash requirements for equity. This lead-lag study calculates the net lag days for natural
2 gas services for the 12-month period ending December 31, 2015.

3 **Q. Please describe the approach you used in preparing your lead-lag study.**

4 A. I began the lead-lag study with the selection of the per-books revenues and expenses for
5 the 12-month period ended December 31, 2015 for NorthWestern's gas services to form
6 the basis for my analysis. I then determined the lag days in the recovery of revenue by
7 type of revenue (i.e., sales and other revenues). For operation and maintenance ("O&M")
8 expenses, I developed lag days for each of several types of expenses (i.e., labor, Gas
9 Transmission and Gathering, employee benefits, Pension Expenses, Automobile Rentals,
10 Debit Card Payments (E Card), Credit Card Payments (P Card), prepayments, and other
11 O&M expenses). In addition, I developed lag days for property taxes, other taxes,
12 income taxes, and interest expense. Once the expense lag days for the test year are
13 established on a per-books basis, they are applied to the test year preliminary pro forma
14 expenses. The lead or lag days for each of the expense items described above are then
15 multiplied by the test year preliminary pro forma amounts to determine the weighted
16 dollars of each expense. The total of the weighted dollars was divided by the total of the
17 preliminary pro forma expenses to compute the total working capital expense lag. The
18 net of the revenue lag and the expense lags determined the net lead-lag days for the
19 calculation of CWC.

20 **Methods of Computation**

21 **Q. Please describe your calculation of revenue lags.**

22 A. The calculation of the gas services revenue lag is summarized on page 2 of
23 Exhibit__(PMN-1). As previously described, "revenue lag" is the length of time that

1 occurs between NorthWestern's provision of service to its customers and the subsequent
2 receipt of payment for those services. The existence of a revenue lag makes it necessary
3 for investors to provide the funding for NorthWestern to pay its operating costs during
4 the lag period.

5 The measurement of revenue lag days typically consists of four components: (1) service
6 lag, (2) billing lag, (3) collection lag and (4) revenue float. Since the time periods for
7 these four components are mutually exclusive, revenue lag is computed by adding
8 together the total number of days associated with each of the four revenue lag
9 components. This total number of lag days represents the amount of time between the
10 recorded delivery of service to customers and the receipt of the related revenues from
11 customers.

12 **Q. Please describe how you calculate service lag.**

13 A. The service lag is the average time span between the mid-point of the customer's
14 consumption interval, also known as the usage period, and the time that such usage is
15 recorded by NorthWestern for billing purposes. This service period determines the
16 average length of time over which the billed services are provided and establishes a
17 common point in time from which to measure (1) the time to reimbursement for the billed
18 services, and (2) the time at which the accrued costs for the service period are actually
19 paid. For virtually all utilities, the service lag is one-half of an average month or 15.21
20 days (365/12/2).

21 **Q. Please describe your calculation of billing lag.**

1 A. The billing lag is the time required to process and send out customer bills. The billing lag
2 begins at the end of the service period when customer consumption is metered, and it
3 ends when the bills are rendered and billings are posted to accounts receivable. The
4 billing lag may be influenced by factors such as whether automated or manual meter
5 reading systems are employed, the generation of invoices from this metering data and
6 other processes affecting the time to post billings to accounts receivable. NorthWestern
7 utilizes automated billing and manual billing which influence the billing lags. The
8 NorthWestern billing lag, which also considers the delay for weekends and holidays, was
9 approximately 3.38 days for automated billing and 8.84 days for manual billing.

10 **Q. Please describe your calculation of collection lag.**

11 A. The collection lag identifies the time delay between the posting of customer bills to
12 accounts receivable and the receipt of these billed revenues. Collection lag begins with
13 the posting of bills and ends with the receipt of payment. Collection lag may be
14 influenced by payment arrangements, contract terms, postal delivery delays, customer
15 inquiries, delinquent accounts, service termination practices, and other factors. I have
16 employed the accounts receivable turnover ratio method to determine the collection lags.
17 Using this approach, the average monthly accounts receivable balances were divided by
18 the average daily revenues for the 12 months ended December 31, 2015. Using the
19 accounts receivable turnover method, a collection lag of 24.13 days was computed.

20 **Q. Please describe the final component of revenue lag, revenue float.**

21 A. Revenue float is the time difference between when funds are received from customers
22 until customer payments clear the banks and are available to NorthWestern. To clarify,
23 there are two periods of float. The first is associated with NorthWestern's payment of

1 services from vendors. The second period of float is the delay in NorthWestern's receipt
2 of cash from the deposited customer payments. In this latter instance, NorthWestern's
3 cash requirements are reduced by the delay in check processing. Some lead-lag studies
4 assume that revenue float and check float are equal and offsetting and, therefore, can be
5 removed.

6 A closer examination reveals that the issue is much more complex. The majority of
7 NorthWestern's larger payments are made by wire transfer with a much shorter lag than a
8 conventional mailed check. On the revenue side, a portion of customer payments are
9 made by cash, credit card or bank transfer. Again, these payments have smaller lag times
10 to clear than conventional checks. Since the dollar volume of utility payments far
11 exceeds their receipts made by cash, credit card and bank transfer, the inclusion of check
12 float in the lead-lag study would slightly increase CWC requirements. I have chosen to
13 avoid this level of complexity with the knowledge that our simplifying assumption will
14 be conservative and slightly understate CWC and will not disadvantage customers.
15 Therefore, I have chosen not to quantify float for revenues or expenses in this study.

16 **Q. How is the lag for labor expense determined?**

17 A. The large majority of NorthWestern's payroll stems from 26 biweekly payroll
18 disbursements. For each two-week period ending on a Friday, employees are normally
19 paid the following Friday. For each pay period, MAC identified the pay period and the
20 payment dates. However, not all of the labor costs earned by employees in the pay period
21 are paid out along with salary. In order to make an accurate calculation of total labor
22 costs, MAC identified all of the labor-related costs and identified when NorthWestern
23 was required to expend cash. These labor-related costs include all salary including

1 incentive compensation, payroll taxes including withholding taxes, and a wide range of
2 benefits. The lags for each component of labor-related costs were developed as part of
3 the lead-lag study.

4 Employee net payroll payments are the largest component of labor costs and have the
5 shortest payment lag at 13.96 days. However, other components of labor costs have
6 exceptionally long delays. For example, 2015 incentive pay earned during the course of
7 the year was paid on March 14th of the following year resulting in an expense lag of 256
8 days. An even more extreme example is the sellback of unused vacation time.
9 Employees occasionally earn more vacation than they use resulting in an accumulation of
10 paid time off. MAC estimates that payments for unused vacation time occur on average
11 over seven years after the vacation is actually earned. The impact of vacation is
12 substantial. The net lag for all labor-related costs is 42.10 days when considering
13 incentive pay and vacation sellback. In addition to direct labor expense, we examined
14 other labor-related costs to NorthWestern, including Payroll Taxes and Pensions and
15 Benefits as discussed below.

16 **Q. Please describe how the lag is calculated for Pensions and Benefits.**

17 A. The method for calculating expense lags for Pensions and Benefits follows the same
18 approach used for all other lag calculations. For each expense, the service period and its
19 mid-point were determined. Then the payment date was established. The lag was then
20 computed as the difference between the payment date and the mid-point of the service
21 period. Next, a weighted average of each expense was computed to determine the overall
22 average for this category.

1 **Q. Were other categories of O&M expense analyzed separately and included in the**
2 **expense lag?**
3 A. Yes. Gas Transmission and Gathering and Automobile Rental expenses were analyzed
4 separately and included in the calculations of the expense lag. Again, the lags for each
5 expense item were computed as the difference between the payment date and the mid-
6 point of the service period.

7 E Card payments and P Card payments were also analyzed separately. E Card payments
8 are payments made for vendor service by way of issuing of a debit card by the Bank of
9 America. The lags for these payments were computed as the difference between the
10 payment date made to the bank for the E Cards and the mid-point of the service period. E
11 Card payments have longer expense lags due to the amount of time associated with
12 processing the invoice and sending the approved payment to the bank and the issuance of
13 the E Card and subsequent payment to the bank by NorthWestern.

14 P Card payments are credit card purchases made by employees for mostly small
15 expenditures. The lags for these payments were computed as the difference between the
16 payment date made to the Bank of America for the P Card and the mid-point of the credit
17 card service period.

18 **Q. Were Prepaid Expenses analyzed separately in the lead-lag study?**
19 A. After review of the payment vouchers for Other O&M expenses, it was noted that
20 NorthWestern had a number of large prepayments for items whose service period was
21 365 days. Those items with payments over $100,000 and service periods of 365 days
22 were analyzed separately and the lead days computed. The lead days were then

computed as the difference between the payment date and the mid-point of the service period. Next, a weighted average of each prepayment was computed to determine the overall average for this category.

Q. How is Uncollectible Accounts expense included in the lead-lag study?

A. Uncollectible Accounts expense for gas services revenues was not assigned lead or lag days in the study because it is a non-cash item. The Acct 904 – Uncollectible Accounts expense was excluded in the calculation of the operating expense lag.

Q. Are there Other O&M expenses that were included in the calculation of expense lag?

A. Yes, there are Other O&M expenses directly paid by NorthWestern. Because these expenses are made up of thousands of vouchers processed throughout the course of the test year, a sample (as discussed below) was used to estimate the lags for NorthWestern. The listing of payment vouchers for our O&M sample included common electric and gas payments and payments directly related to electric or gas expenses. Because NorthWestern was unable to separate out the common and direct payments to gas and electric, a sample was made on all expense vouchers. The sample produced a lag of 33.29 days for these Other O&M direct expenses.

The sampling method used was a random sequential sample of the population using four (4) strata. The population was sorted by dollar amounts, and the following strata were used for the sample:

Stratum 1	–	Largest vouchers – over $100,000
Stratum 2	–	Every 25th voucher down to $15,000
Stratum 3	–	Every 100th voucher down to $4,000
Stratum 4	–	Every 500th voucher under $4,000

1 The resulting sample accounted for 9.22% of the dollars in the population and resulted in
2 a lag of 33.29 days for the Other O&M expenses.

3 **Q. Did you include any other expenses besides O&M expenses in the calculation of the**
4 **expense lag?**

5 A. Yes. Since Property Taxes, Other Taxes, Federal and State Income Taxes, and Interest
6 on Long Term Debt represent cash outlays, they were included in the 2015 test period in
7 the calculation of lag days. All property tax payments made during 2015 were analyzed,
8 and the expense lags computed. Other Taxes consist mostly of Payroll Taxes and Other
9 Miscellaneous Taxes. Each type of tax was analyzed separately and assigned a lag based
10 on the service periods and payment dates. Federal and State Income Taxes were assigned
11 lags based on the statutorily required equal quarterly tax payments during the test year.
12 Interest on Long Term Debt was assigned lags based on the actual interest payments for
13 the 2015 test period.

14 **Results of the NorthWestern Energy Lead-Lag Study**

15 **Q. What were the net lag days between revenue and expense for NorthWestern's**
16 **Montana gas services in 2015?**

17 A. As indicated by the data in Exhibit__(PMN-1), the net lag for NorthWestern's gas
18 services as measured by the lead-lag study, excluding interest expense, was -65.21 days.
19 The negative figure indicates that gas services does not require stockholder capital.
20 Instead, it suggests that ratepayers are providing a source of capital, which reduces the
21 amount of CWC required from stockholders.
22

1 **Q. Referring to Exhibit__(PMN-1), could you discuss the structure of your lead-lag**
2 **study summary?**
3 A. The summary of my gas services lead-lag study is shown on page 1, which also includes
4 the summary of the expense lag data.

5 These calculations are based primarily on preliminary pro forma expenses. For each
6 category of expense, the expense, along with its lag days, is tabulated. In order to
7 compute subtotals and totals, the rightmost column, labeled "Weighted Amount," is also
8 shown. For those categories with known lag days, this column is the simple product of
9 the annual expense and the lag days. For rows displaying subtotals and totals, this
10 column is computed and then used along with the appropriate figure from the Annual
11 Expense column to compute the average lag. Row 31 of this exhibit shows that the
12 weighted average lag of all expenses is 109.09 days. Since revenues are received 43.88
13 days after the service is provided, the net lag for all expenses is -65.21 days after the
14 revenues are received, as shown on Row 36. Since this figure is negative, the revenues
15 lead the expenses. Stated differently, the revenues in aggregate are received before the
16 expenses are paid, so operations provide a source of cash.

17 **Q. What else influenced how you structured your lead-lag study summary?**
18 A. The MPSC has previously established that the cash requirements associated with interest
19 and preferred equity should be included in the CWC requirements.[1] Since all of
20 NorthWestern's natural gas utility-related plant in service is in gas services, I have
21 assumed that all of the interest expense should also be assigned to gas services. On lines
22 40 to 42, I compute the interest expense net lag days. Since NorthWestern currently has

[1] MPSC Docket No. 90.6.39 Order 5484k.

1 no preferred stock, the calculation is limited to the calculation of net lag days for debt.
2 The method I used mirrors that adopted by the MPSC. The lag of Long-Term Debt
3 interest payments is 92.29 days, resulting in a net lag of negative 48.41 days. This
4 translates into an additional generation of CWC and a reduction to stockholder-supplied
5 CWC requirements.

6 **Q. Please explain how test year CWC should be computed.**

7 A. My lead-lag study computes representative lag days for revenues and a number of
8 categories that make up revenue requirements. The proper calculation of test year CWC
9 should apply the net lag days to the pro forma test year level of revenue requirement.
10 Using this approach, the computed CWC will properly reflect any and all adjustments
11 deemed appropriate for ratemaking purposes

12 **Q. Do you agree with the lead-lag study methodology previously approved by the**
13 **MPSC?**

14 A. No I do not. The underlying purpose of a lead-lag study is to compute a CWC
15 adjustment to rate base to account for the timing differences between revenues and
16 expenses. The goal is to ensure that stockholders have a fair opportunity to earn the level
17 of return on investment deemed appropriate by the utility's regulators. That investment
18 includes CWC. If revenues lag expenses, then stockholders must invest capital to support
19 the utility's operations, or if expenses lag revenues, then the utility's operations provide a
20 source of capital reducing the investment otherwise required from stockholders. The
21 present ordered structure of the NorthWestern lead-lag study includes specific items from
22 the utility's revenue requirement for the calculation of CWC. I believe that the proper
23 approach to computing CWC is to identify the lag in <u>all</u> revenues and then deduct from it

1 the lag in payment of all expenses related to revenue requirements. This approach is
2 straight-forward, is internally consistent, and does not require the MPSC to selectively
3 exclude items from the calculation. More importantly, this approach is theoretically
4 appropriate and provides utilities with a fair and reasonable opportunity to earn their
5 authorized rate of return.

6 **Q. Are you recommending that the Commission revise its method to compute working**
7 **capital?**
8 A. Not at the present time. While I believe that the methods used in the lead-lag study filed
9 here result in an underestimate of NorthWestern's actual CWC needs, my purpose here is
10 only to present the results of the lead-lag study conducted in compliance with past MPSC
11 precedent.

12 **Q. Please summarize your testimony regarding the lead-lag study.**
13 A. I have prepared a gas services lead-lag study to separately compute the lag days
14 associated with revenue collection from customers and the lag days associated with the
15 utility revenue requirement expenses for gas services. These lagged revenues and
16 expenses are combined to determine the net lag days for NorthWestern. Based on the
17 lead-lag study methodology previously used by the MPSC, the net lag data is summarized
18 in Exhibit__(PMN-1) for gas services. The table below summarizes the results of the
19 study I have conducted:

Description	Natural Gas Services MPSC Method
Revenue Lag Days	43.88
Expense Lag Days	109.09
Net Lag	-65.21
Interest Lag Days	92.29
Net Lag	-48.41

The use of the net lag days, when applied to the pro forma test year level of revenue requirement, will provide reasonable estimates of NorthWestern's gas services CWC requirements for the 2015 test year.

Q. Does this conclude your testimony?

A. Yes, it does.

NorthWestern Energy
Cash Working Capital Requirements Natural Gas Delivery
12 Months Ended Dec 31, 2015
Natural Gas Services Lead Lag Summary

Line No		Prelim Pro Forma Annual Expense	(Lead) Lag Days	Weighted Amount
1	**Total Revenue Lag Gas Delivery**		43.88	
2				
3	**Operation & Maintenance Expense**			
4	Labor	$25,077,548	42.10	$1,055,734,616
5	Gas Transmission & Gathering	$4,536,032	44.45	$201,625,128
6	Fringe Benefits - Acct 926	$11,720,587	190.11	$2,228,159,756
7	Fringe Benefits - Acct 925	$568,483	35.42	$20,135,990
8	Automotive Rentals	$988,002	34.17	$33,764,244
9	E Cards	$2,275,154	59.36	$135,047,554
10	P Cards	$1,968,303	28.02	$55,154,563
11	Large Prepayments	$1,312,359	-119.10	-$156,299,953
12	Other Excluding Acct 904 & Non Cash Items	$14,745,700	33.29	$490,924,015
13	Acct 904 Uncollectible Accounts	$532,508		
14	Total Operation & Maintenance Exp Excluding 904	$63,192,168	64.32	$4,064,245,913
15				
16	**Other Taxes**			
17	Other Taxes Excluding Payroll & Property Taxes	$850,750	54.38	$46,264,714
18	Employer Payroll Taxes	$2,678,713	33.91	$90,843,492
19	Property Taxes Gas	$30,966,629	240.54	$7,448,658,721
20	Total Other Taxes	$34,496,091	219.90	$7,585,766,927
21				
22	**Depreciation & Amortization**			
23				
24	**Pension Differential**	(2,411,148)	392.50	-$946,375,590
25				
26	**Income Taxes**			
27	Federal Income Taxes	$4,922,440	36.75	$180,899,683
28	MT State Income Taxes	-$639,083	36.75	-$23,486,305
29	Deferred Income Taxes			
30				
31	**Total Requirements for Working Capital Expenses**	$99,560,468	109.09	$10,861,050,627
32				
33				
34	Revenue Lag Days		43.88	
35	Requirement Lag Days		109.09	
36	**Net Lag Days for Operating Expenses**		-65.21	
37				
38				
39	**Interest Expense in Return**			
40	Revenue Lag Days		43.88	
41	Interest Expense in Return		92.29	
42	**Net Lag Days for Interest Expense**		-48.41	
43				
44				
45				

NorthWestern Energy
Cash Working Capital Requirements Natural Gas Delivery
12 Months Ended Dec 31, 2015
Natural Gas Services Revenue Lag Summary

Line No	Gas Delivery Revenue Lag	Delivery Rev Billed	(Lead) Lag Days	Notes	Wtg Delivery Dollar Days
1	Service Lag		15.21	1	
2					
3	Billing Lag				
4	Automated Billing Lag	$89,193,346	3.38		$301,257,641
5	Gas Transportation Revenues	$23,121,806	8.84		$204,344,181
6	Total Billing Lag	$112,315,151	4.50		$505,601,822
7					
8					
9	Collection Lag		24.13		
10					
11	Total Revenue Lag Gas Delivery Rate Schedule	$112,315,151	43.84		$4,923,551,676
12					
13	Offsystem Sales	$63,978	40.21		$2,572,458
14					
15	On System Transportation	$16,431,381	43.84	2	$720,301,336
16					
17	NG Processing & Gathering	$1,616,260	47.28		$76,419,829
18	NG Processing & Gathering	$170,463	43.84	2	$7,472,596
19					
20	Utility Oil and Liquid Sales	$167,203	40.21		$6,722,960
21					
22	Rents - Land	$1,000	-15.21		-$15,208
23					
24	Other Revenue-Miscellaneous	$879,337	45.21		$39,753,370
25					
26	Other Revenue-Material Sales	$10,175	0.00		$0
27					
28					
29	Total Revenue Lag Gas Delivery	$131,654,950	43.88		$5,776,779,015
30					
31					
32	Notes:				
33	1. Computed as 365/12/2				
34	2. Lag Days from Line 11.				
35					

QUALIFICATIONS

PAUL M. NORMAND

Principal

Experience in the electric, gas, and water industry includes project management of various cost analyses, engineering system planning and design functions, detailed electric power loss analyses, as well as cost and contract functions for a manufacturer of nuclear equipment. Also, experienced in the analysis and preparation of economic data, revenue requirements and rate design for presentation before state and federal regulatory agencies. Presented expert testimony on behalf of utilities in over 30 applications before regulatory commissions.

EXPERIENCE:

1984 - Present **MANAGEMENT APPLICATIONS CONSULTING, INC.**
Principal consultant providing consulting services to industry in planning, pricing, and regulation. Extensive experience in analyzing power systems for power loss studies and unbundling issues.

1983 - 1984 **P. M. NORMAND ASSOCIATES**
Independent consultant providing services to the utility industry in cost analyses, rate design and expert testimony.

1976 - 1983 **GILBERT/COMMONWEALTH**, Reading, Pa.
Director, Rate Regulatory Services - Administrative and fiscal responsibility for rate and regulatory services nationally for electric, gas, and water utilities. Additional responsibilities included all marketing, research and development efforts, and contract negotiations for all studies performed by the Regulatory Service Department. Provided consulting service to utilities in project management, personnel staffing, and future development efforts.

Manager, Austin, Texas Office - Responsibility for the overall administrative and business aspects for the department in the Southwest. Duties included the preparation of all aspects of rate cases and PURPA compliance studies.

Senior Management Consultant - Responsibilities included project management of various electric and gas cost-of-service studies and the development of methodologies utilized in the analysis of time-differentiated average and marginal cost studies.

Consulting Engineer - Prepared class and time-differentiated cost-of- service studies, revenue requirements exhibits, and expert testimony for formal rate proceedings before regulatory agencies. Performed forecasted ten-year cost-of-service studies by customer classes. Analyzed and prepared transmission (wheeling) rates based on cost-of-service.

Engineer - Derived system demand and energy loss factors and customer load characteristics required for cost-of-service results and related rate schedules.

1975 - 1976 **WESTINGHOUSE ELECTRIC CORPORATION**, Pittsburgh, PA
Responsible for the procurement of electrical/electronic control equipment and power cables for the nuclear reactor control system. Assisted in the development of procedures for the seismic testing of various electronic equipment related to reactor control.

1971 - 1974 **NEW ENGLAND ELECTRIC SYSTEM**, Westborough, Massachusetts
Experience from various system assignments in conjunction with formal education. Assigned to the Transmission and Distribution Department with responsibilities in several voltage conversion efforts and system planning. Development of network modeling techniques, load flow, and fault study analyses for the system planning department.

1966 - 1970 **U.S. NAVY**
Aviation electronic technician with responsibilities for maintenance and trouble-shooting of electronic communication equipment.

EDUCATION:

B.S.E.E., Electrical Engineering, Northeastern University, 1975
M.S.E.E., Electrical Power Systems, Northeastern University, 1975

Graduate Studies - MBA Program, Lehigh University and Albright College, 1977 to 1980

SOCIETIES:

Institute of Electrical and Electronic Engineers

APPEARANCES AS EXPERT WITNESS:

Federal Energy Regulatory Commission
Arkansas Public Service Commission
Delaware Public Service Commission
Indiana Utility Regulatory Commission
Illinois Commerce Commission
Kansas Corporation Commission
Kentucky Public Service Commission
Louisiana Public Service Commission
Maine Public Utilities Commission
Maryland Public Service Commission
Massachusetts Department of Public Utilities
Missouri Public Service Commission
New Hampshire Public Utilities Commission
New Jersey Board of Public Utilities
New York Public Service Commission
North Carolina Utilities Commission
Ohio Public Utilities Commission
Pennsylvania Public Utility Commission
Rhode Island Public Utilities Commission
Texas Public Utilities Commission

PAPERS AND PRESENTATIONS:

"Probability of Dispatch Costing Method for Electric Utility Cost-of-Service Analysis." Co-authored with P. S. Hurley, presented to Edison Electric Institute Rate Research Committee May 4, 1982.

"Costing Strategies under Changing Marketing Goals and Long Term Investment Growth." Presented to Missouri Valley Electric Association (MVEA), Kansas City, MO, November 13, 1991.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF PATRICK J. DIFRONZO

ON BEHALF OF NORTHWESTERN ENERGY

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Exhibits

2013 Bear Paw (NFR) Revenue Requirement	Exhibit__(PJD-1)
2014 Bear Paw (NFR) Revenue Requirement	Exhibit__(PJD-2)
2015 Bear Paw (NFR) Revenue Requirement	Exhibit__(PJD-3)
2014 South Bear Paw (Devon) Revenue Requirement	Exhibit__(PJD-4)
2015 South Bear Paw (Devon) Revenue Requirement	Exhibit__(PJD-5)
True-up of Bridge Rates Bear Paw (NFR)	Exhibit__(PJD-6)
True-up of Bridge Rates South Bear Paw (Devon)	Exhibit__(PJD-7)
Forecast 2016 – 2019 Revenue Requirement Battle Creek	Exhibit__(PJD-8)
Forecast 2016 – 2019 Revenue Requirement Bear Paw (NFR)	Exhibit__(PJD-9)
Forecast 2016 – 2019 Revenue Requirement South Bear Paw (Devon)	Exhibit__(PJD-10)
2015 Natural Gas Delivery Services Test Period Income Statement	Exhibit__(PJD-11)
2015 Natural Gas Delivery Services Revenue Requirement	Exhibit__(PJD-12)

2015 Battle Creek Test Period Income Statement	Exhibit__(PJD-13)
2015 Bear Paw (NFR) Test Period Income Statement	Exhibit__(PJD-14)
2015 South Bear Paw (Devon) Test Period Income Statement	Exhibit__(PJD-15)
2015 Production Administration Test Period Income Statement	Exhibit__(PJD-16)
2015 Natural Gas Production Assets Revenue Requirement	Exhibit__(PJD-17)
2015 Natural Gas Operating Revenues Delivery Services	Exhibit__(PJD-18)
2015 Natural Gas Operating Revenues Production Assets	Exhibit__(PJD-19)

Witness Information

Q. Please state your name and business address.

A. My name is Patrick J. DiFronzo. I work at 11 East Park, Butte, Montana 59701.

Q. By whom are you employed and in what capacity?

A. I am NorthWestern Energy's ("NorthWestern") Manager of Regulatory Affairs.

Q. Please summarize your education and employment experience.

A. I graduated from Montana State University with a Bachelor of Science degree in Accounting in 1981. In August 1983, I completed the requirements to become a Certified Public Accountant. I have also attended several rate-related courses since beginning my employment at Montana Power Company ("MPC"), NorthWestern's predecessor, in July 1984. The first position I held

1 was Accountant in the Income Tax Department from 1984 through 1989.
2 During this time, I worked on several Montana Public Service Commission
3 ("MPSC" or "Commission") and Federal Energy Regulatory Commission
4 ("FERC") rate filings by preparing tax statements and exhibits. I then spent a
5 year in the Regulatory Affairs Department as part of a cross-training program
6 learning more about cost of service and other regulatory matters. After this, I
7 transferred into Internal Auditing where I spent the next six years working on
8 various financial and information system control audits. In 1996, I transferred
9 into the Financial Resources Department as a Senior Analyst. In the
10 Financial Resources Department, I prepared annual and forecasted business
11 plans for MPC and performed various financial analyses. In May of 1999, I
12 was promoted to Manager of Treasury Services. In the Treasury Department,
13 I worked on several MPSC and FERC rate filings by preparing cost of capital
14 statements and exhibits. In October of 2000, I accepted a position in the
15 Regulatory Affairs Department as a Senior Analyst. In December of 2003, I
16 was promoted to Manager of Regulatory Affairs.
17
18 **Q. What are your responsibilities as Manager of Regulatory Affairs?**
19 **A.** I am the manager in charge of state and federal regulatory activities for
20 NorthWestern in Montana. In my present role, among other things, I
21 participate in the preparation and/or consideration of the testimony, exhibits,
22 and work papers in NorthWestern's proceedings before the MPSC and
23 FERC.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. My testimony:

1. Presents the development of the Bear Paw (NFR) Natural Gas Production Asset Cost of Service ("Test Period Revenue Requirement") and the derivation of fixed rates for years 2013 through 2015;
2. Presents the development of the South Bear Paw (Devon) Natural Gas Production Asset Cost of Service ("Test Period Revenue Requirement") and the derivation of fixed rates for years 2014 and 2015;
3. Presents the true-up of the revenues collected from customers for the Bear Paw (NFR) and South Bear Paw (Devon) natural gas production properties based on the bridge or interim rates compared to the rates from the updated revenue requirements proposed;
4. Presents the development of the Bear Paw (NFR), South Bear Paw (Devon), and Battle Creek Natural Gas Production Assets Cost of Service ("Test Period Revenue Requirement") based on projected multi-year[1] revenue requirements and the derivation of fixed rates for years 2016 through 2019;
5. Includes the Natural Gas Utility Income Statement Exhibits which I sponsor and explains the adjustments or a portion of those adjustments

[1] Per paragraph 33 in Commission Order No. 7282d, Docket Nos. D2013.5.34 and D2014.5.47.

that were made to the actual expenses in developing the 2015 test period cost of service as presented in these income statements;

6. Includes the Natural Gas Utility Revenue Requirement Exhibit which I sponsor and explain. This exhibit shows the revenue requirement calculation for the test period cost of service; and
7. Presents the Natural Gas Utility Operating Revenues.

Natural Gas Production Assets – True-Up

Bear Paw (NFR) Revenue Requirement

Q. Have you prepared an exhibit that presents the calculation of the Bear Paw (NFR) Revenue Requirement for each year from 2013 through 2015?

A. Yes, Exhibit__(PJD-1) through Exhibit__(PJD-3) ("Exhibits 1-3") include these Revenue Requirement calculations. Page 1 of each of these exhibits presents a line-by-line summary of the return and cost of service elements that make up the revenue requirement, followed by work papers further supporting these line items.

Q. How did you develop the Cost of Service or Total Revenue Requirement?

A. The standard regulated revenue requirement formula shown below was used to develop the revenue requirements:

$$RR = [(AC - D) * RoR] + E$$

Where: RR = Revenue Requirement

AC = Asset Cost

D = Accumulated Depreciation/Depletion adjusted for Deferred Income Taxes

RoR = Allowed Rate of Return

E = Expenses (i.e., Operation and Maintenance, Administrative and General, Depreciation, Taxes Other than Income, and Income Taxes)

The detailed elements of the above equation as they relate to the natural gas production assets are explained below.

Detailed Bear Paw (NFR) Revenue Requirement Elements

Q. Please provide a general description of each cost of service element on page 1 of Exhibits 1-3.

A. A general description of each cost of service element is provided below. Further detail is included in the supporting work papers in Exhibits 1-3.

Q. Please address the basis NorthWestern used for determining the asset value in its revenue requirement computation.

A. The Utility Plant in Service section of page 1 of Exhibits 1-3 includes the year-end and 13-month average balance on line 13 and on page 7 for each of the years. The Prefiled Direct Testimony of Crystal D. Lail ("Lail Direct Testimony") provides an explanation of rate base. The Prefiled Direct

Testimony of Patrick E. Callahan ("Callahan Direct Testimony") provides an explanation of NorthWestern's purchase of the Bear Paw (NFR) properties.

Q. Please describe the Accumulated Depreciation and Depletion on page 1, line 16 of Exhibits 1-3.

A. The computation of depreciation and depletion is addressed in the Lail Direct Testimony. The depreciation and depletion accrual computations are reflected on page 6, and the accumulated depreciation and depletion year-end balance and 13-month average is shown on page 7 on each of the exhibits.

Q. Please describe the Deferred Income Taxes – Accelerated Tax Depreciation/Depletion on page 1, line 21 on Exhibits 1-3.

A. As explained in the Prefiled Direct Testimony of Wayne M. Hitt ("Hitt Direct Testimony"), this rate base adjustment reflects the deferred income taxes resulting from the difference between book and tax depreciation/depletion. See page 2 for the computation of book and tax depreciation/depletion deferred tax computation. The accumulated year-end balance and 13-month average is shown on page 7 on each of the exhibits. Page 3 includes the Tax Depreciation/Depletion Summary also sponsored by Mr. Hitt.

Q. Please describe how the Total Year End Rate Base on page 1, line 25 in Column D was derived on Exhibits 1-3.

1 **A.** The Total Year End Rate Base was derived by taking the Total Plant amount
2 on line 13, minus the accumulated depreciation and depletion on line 16,
3 minus the customer-contributed capital amount on line 23.
4
5 **Q. Please describe how the 13-Month Average Rate Base on page 1, line 25**
6 **in Column F was derived on Exhibits 1-3.**
7 **A.** This value represents the total of the 13-month average, for the period from
8 December of the previous year through December of the current year, of the
9 rate base items shown in Column D, lines 13, 16, and 23.
10
11 **Q. Please describe the Rate of Return on page 1, line 27 of Exhibits 1-3.**
12 **A.** The computation of the 7.63% rate of return is shown on page 4. The Prefiled
13 Direct Testimony of Daniel L. Rausch ("Rausch Direct Testimony") provides
14 explanation of the rate of return and support for its components.
15
16 **Q. Please describe how the Authorized Return on page 1, line 29 was**
17 **developed on Exhibits 1-3.**
18 **A.** The authorized return is computed by multiplying the 13-Month Average Rate
19 Base, Column F, line 25, by the rate of return.
20
21 **Q. Please explain the Operation and Maintenance Expenses on page 1, line**
22 **32 on Exhibits 1-3.**

1 **A.** This represents the annual operation and maintenance ("O&M") costs to
2 operate and maintain Bear Paw (NFR). These costs are 12 months of actual
3 expenses incurred for each of the years adjusted for any known and
4 measurable changes. These expenses are detailed on page 5 for each year
5 along with any adjustments. The royalty expense amount included in the
6 O&M costs is backed out of the revenue requirement on line 47 because it is
7 recovered through the natural gas supply tracker filing as a variable cost.
8 Royalty payments are variable costs that change with the amount of
9 production and the index price of natural gas. Since these costs vary over
10 time, it is appropriate that they are included in the natural gas tracker.
11
12 **Q. Were there any adjustments made to the actual O&M costs?**
13 **A.** Yes, in year 2014 Exhibit__(PJD-2) page 5 shows an adjustment to eliminate
14 the prior period accounting and allocation adjustment relating to the proper
15 allocation of Bear Paw (NFR) in the amount of ($1,153,050). In year 2015
16 Exhibit__(PJD-3) page 5 shows an adjustment made to eliminate the write-off
17 of obsolete inventory for ($55,645).
18
19 **Q. Please explain Depreciation and Depletion Expenses on page 1, lines 33**
20 **and 34 on Exhibits 1-3.**
21 **A.** This represents the 12 months of actual book depreciation and depletion for
22 each of the years. The depreciation and depletion accrual computation is

reflected on page 6 for each of the years. The computation of depreciation and depletion is addressed in the Lail Direct Testimony.

Q. Please explain the Property and Other Taxes on page 1, line 35 on Exhibits 1-3.

A. This represents the 12 months of actual production and property taxes for each of the years, as well as labor and vehicle taxes. These expenses are detailed on page 5 for each of the years.

The production tax amount is backed out of the revenue requirement on line 46 because it is recovered through the natural gas supply tracker filing as a variable cost. Production-related taxes are variable costs that change with the amount of production and the index price of natural gas. Since these costs vary over time, it is appropriate that they are included in the natural gas tracker.

Q. How were the Montana Consumer Counsel ("MCC") and MPSC taxes on page 1, line 36 computed on Exhibits 1-3?

A. These taxes were based on the tax rates applicable during the respective test years. These tax rates are applied to the Total Revenue Requirement as shown on page 1, line 50 to derive the amount of taxes, and the resulting taxes are included in the Total Revenue Requirement on line 50.

1 **Q. What are the Miscellaneous and Other Revenues reflected on page 1,**
2 **lines 37 through 44 on Exhibits 1-3?**
3 **A.** They represent 12 months of actual non-operating and miscellaneous
4 revenues for each of the years. These revenues are a reduction to the cost of
5 service.
6
7 **Q. Describe the Deferred Income Taxes Amount shown on page 1, line 41**
8 **on Exhibits 1-3.**
9 **A.** This reflects the level of deferred income taxes resulting from the timing
10 difference between book and tax depreciation and depletion. This figure is
11 derived on page 2, lines 86 to 92. Deferred Income Taxes have been
12 reviewed and approved by, and are sponsored by, Mr. Wayne Hitt,
13 NorthWestern's Director – Corporate Taxes.
14
15 **Q. Please explain the computation of Current Income Taxes shown on**
16 **page 1, line 42 on Exhibits 1-3.**
17 **A.** Current federal and state income tax rates are used to compute income
18 taxes. The details of the income tax calculations are shown on page 2, lines
19 58 through 84. The tax depreciation and depletion used in computing current
20 income taxes is shown on page 3. Current Income Taxes have also been
21 reviewed and approved by and are sponsored by Mr. Hitt.
22

1 **Q. What is included in the Total Revenue Requirement shown on page 1, line**
2 **50 on Exhibits 1-3?**
3 **A.** This total includes the Authorized Return (page 1, line 29), plus the Total Cost
4 of Service (page 1, line 43), less the Variable Cost of Service (page 1, line
5 48).
6
7 **Q. Has NorthWestern computed the actual fixed cost unit rate for Bear Paw**
8 **(NFR) for each of the years on page 1 of Exhibits 1-3?**
9 **A.** Yes. The fixed cost unit rate per dekatherm[2] ("Dkt") is shown on page 1, line
10 54. This rate is derived by dividing the Total Revenue Requirement on line 50
11 by the test period load on line 52. The fixed cost unit rate for each of the
12 years is shown in the table below. These unit rates are then compared to the
13 bridge rates that were used to charge customers during the interim time
14 period. The true-up of revenues collected from customers is discussed
15 below.

	2013	2014	2015
Fixed Unit Rate (Dkt)	$0.2522	$0.2232	$0.2090

16 **<u>South Bear Paw (Devon) Revenue Requirement</u>**
17 **Q. Have you prepared an exhibit that presents the calculation of the South**
18 **Bear Paw (Devon) Revenue Requirement for 2014 and 2015?**

[2] Dekatherms are converted to therms for customer billing purposes. One dekatherm equals 10 therms.

1 **A.** Yes, Exhibit__(PJD-4) and Exhibit__(PJD-5) ("Exhibits 4-5") include these
2 Revenue Requirement calculations. Page 1 of each of these exhibits
3 presents a line-by-line summary of the return and cost of service elements
4 that make up the revenue requirement, followed by work papers further
5 supporting these line items.
6
7 *Detailed South Bear Paw (Devon) Revenue Requirement Elements*
8 **Q. Please provide a general description of each cost of service element on**
9 **page 1 of Exhibits 4-5.**
10 **A.** A general description of each cost of service element is provided below.
11 Further detail is included in the supporting work papers in Exhibits 4-5.
12
13 **Q. Please address the basis NorthWestern used for determining the asset**
14 **value in its revenue requirement computation.**
15 **A.** The Utility Plant in Service section of page 1 of Exhibits 4-5 includes the year-
16 end and 13-month average balance on line 13 and on page 7 for each of the
17 years. The Lail Direct Testimony provides an explanation of rate base. The
18 Callahan Direct Testimony provides an explanation of NorthWestern's
19 purchase of the South Bear Paw (Devon) properties.
20
21 **Q. Please describe the Accumulated Depreciation and Depletion on page 1,**
22 **line 16 on Exhibits 4-5.**

1 **A.** The computation of depreciation and depletion is addressed in the Lail Direct
2 Testimony. The depreciation and depletion accrual computations are
3 reflected on page 6, and the accumulated depreciation and depletion year-
4 end balance and 13-month average is shown on page 7 on each of the
5 exhibits.
6
7 **Q. Please describe the Deferred Income Taxes – Accelerated Tax**
8 **Depreciation/Depletion on page 1, line 21 on Exhibits 4-5.**
9 **A.** As explained in the Hitt Direct Testimony, this rate base adjustment reflects
10 the deferred income taxes resulting from the difference between book and tax
11 depreciation/depletion. See page 2 for the computation of book and tax
12 depreciation/depletion deferred tax computation. The accumulated year-end
13 balance and 13-month average is shown on page 7 on each of the exhibits.
14 Page 3 includes the Tax Depreciation/Depletion Summary also sponsored by
15 Mr. Hitt.
16
17 **Q. Please describe how the Total Year End Rate Base on page 1, line 25 in**
18 **Column D was derived on Exhibits 4-5.**
19 **A.** The Total Year End Rate Base was derived by taking the Total Plant amount
20 on line 13, minus the accumulated depreciation and depletion on line 16,
21 minus the customer-contributed capital amount on line 23.
22
23 **Q. Please describe how the 13-Month Average Rate Base on page 1, line 25**

in Column F was derived on Exhibits 4-5.

A. This value represents the total of the 13-month average, for the period from December of the previous year through December of the current year, of the rate base items shown in Column D, lines 13, 16, and 23.

Q. Please describe the Rate of Return on page 1, line 27 of Exhibits 4-5.

A. The computation of the 7.54% rate of return is shown on page 4. The Rausch Direct Testimony provides explanation of the rate of return and support for its components.

Q. Please describe how the Authorized Return on page 1, line 29 was developed on Exhibits 4-5.

A. The authorized return is computed by multiplying the 13-Month Average Rate Base, Column F, line 25, by the rate of return.

Q. Please explain the Operation and Maintenance Expenses on page 1, line 32 on Exhibits 4-5.

A. This represents the annual operation and maintenance ("O&M") costs to operate and maintain South Bear Paw (Devon). These costs are 12 months of actual expenses incurred for each of the years adjusted for any known and measureable changes. These expenses are detailed on page 4 for each of the years along with any adjustments. The royalty expense amount included in the O&M costs is backed out of the revenue requirement on line 47,

because it is recovered through the natural gas supply tracker filing as a variable cost. Royalty payments are variable costs that change with the amount of production and the index price of natural gas. Since these costs vary over time, it is appropriate that they are included in the natural gas tracker.

Q. Were there any adjustments made to the actual O&M costs?

A. Yes, Exhibit__(PJD-4) page 5 shows three normalizing adjustments made to actual 2014 data. The first adjustment reflects road and trail damage expense of $61,835 relating to 2014 that was paid and expensed in 2015. This same amount is then eliminated in 2015. The second adjustment relates to the removal of the overhead credit of $500,400 relating to Havre Pipeline Company ("HPC"). This adjustment is further discussed in Lail Direct Testimony. The third adjustment eliminates the prior period accounting and allocation adjustment relating to the proper allocation of South Bear Paw (Devon) in the amount of ($158,583).

Exhibit__(PJD-5) page 5 also shows three normalizing adjustments made to actual 2015 data. As explained above, the first adjustment reflects elimination of road and trail damage expense of $(61,835) relating to 2014 that was paid and expensed in 2015. The second adjustment relates to the removal of the overhead credit of $500,400 relating to HPC. The third

adjustment of $(17,485) removes expense relating to a write-off of a capital project expensed in 2015.

Q. Please explain Depreciation and Depletion Expenses on page 1, lines 33 and 34 on Exhibits 4-5.

A. These represent the 12 months of actual book depreciation and depletion for each of the years. The depreciation and depletion accrual computation is reflected on page 6 for each of the years. The computation of depreciation and depletion is addressed in the Lail Direct Testimony.

Q. Please explain the Property and Other Taxes on page 1, line 35 on Exhibits 4-5.

A. These represent the 12 months of actual production and property taxes for each of the years, as well as labor and vehicle taxes. These expenses are detailed on page 5 for each year.

The production tax amount is backed out of the revenue requirement on line 46 because it is recovered through the natural gas supply tracker filing as a variable cost. Production-related taxes are variable costs that change with the amount of production and the index price of natural gas. Since these costs vary over time, it is appropriate that they are included in the natural gas tracker filing.

1 **Q. How were the Montana Consumer Counsel ("MCC") and MPSC taxes on**
2 **page 1, line 36 computed on Exhibits 4-5?**
3 **A.** These taxes were based on the tax rates applicable during the respective test
4 years. These tax rates are applied to the Total Revenue Requirement as
5 shown on page 1, line 50 to derive the amount of taxes, and the resulting
6 taxes are included in the Total Revenue Requirement on line 50.
7
8 **Q. What are the Miscellaneous and Other Revenues reflected on page 1,**
9 **lines 37 through 44 on Exhibits 4-5?**
10 **A.** They represent 12 months of actual non-operating and miscellaneous
11 revenues for each of the years. These revenues are a reduction to the cost of
12 service.
13
14 **Q. Describe the Deferred Income Taxes shown on page 1, line 41 on**
15 **Exhibits 4-5.**
16 **A.** These reflect the level of deferred income taxes resulting from the timing
17 difference between book and tax depreciation and depletion. This figure is
18 derived on page 2, lines 86 to 92. Deferred Income Taxes have been
19 reviewed and approved by, and are sponsored by, Wayne M Hitt.
20
21 **Q. Please explain the computation of Current Income Taxes shown on**
22 **page 1, line 42 on Exhibits 4-5.**

1 **A.** Current federal and state income tax rates are used to compute income
2 taxes. The details of the income tax calculations are shown on page 2, lines
3 58 through 84. The tax depreciation and depletion used in computing current
4 income taxes is shown on page 3. Current Income Taxes have also been
5 reviewed and approved by and are sponsored by Mr. Hitt.
6
7 **Q. What is included in the Total Revenue Requirement shown on page 1, line**
8 **50 on Exhibits 4-5?**
9 **A.** This total includes the Authorized Return (page 1, line 29), plus the Total Cost
10 of Service (page 1, line 43), less the Variable Cost of Service (page 1, line
11 48).
12
13 **Q. Has NorthWestern computed the actual fixed cost unit rate for South**
14 **Bear Paw (Devon) for each of the years on page 1 of Exhibits 4-5?**
15 **A.** Yes. The fixed cost unit rate per Dkt is shown on page 1, line 54. This rate is
16 derived by dividing the Total Revenue Requirement on line 50 by the test
17 period load on line 52. The fixed cost unit rate for each of the years is shown
18 in the table below. These unit rates are then compared to the bridge rates
19 that were used to charge customers during the interim time period. The true-
20 up of revenues collected from customers is discussed below.

	2014	2015
Fixed Unit Rate (Dkt)	$0.8539	$0.8014

1 **<u>True-up of Bear Paw (NFR) and South Bear Paw (Devon) Interim Rates</u>**

2 **Q. Has NorthWestern computed the current net difference between**
3 **revenues collected from customers based on interim bridge rates and**
4 **the updated revenue requirements for Bear Paw (NFR)?**

5 **A.** Yes. Refer to Exhibit__(PJD-6). The bridge rates used to bill customers
6 during the interim period are shown in Column C. Column D reflects the
7 amount of Dkts billed customers for each of the months that the bridge has
8 been in place and Column F is the dollar amount billed customers. Column H
9 reflects the updated fixed cost unit rates derived from the revenue
10 requirements computed in Exhibits 1-3. Column J is the updated fixed cost
11 unit rates multiplied by the billed volumes in Column D and shows the
12 revenues that should be collected from customers. Column L shows the
13 under-collection amount. From November 2012 through July 2016 there has
14 been an under-collection of $3,509,811 from customers. Column N reflects
15 the first interim bridge adjustment per Commission Order No. 7282d ¶¶ 42
16 and 43 in Docket Nos. D2013.5.34 and D2014.5.47. This interim bridge[3]
17 adjustment totals ($1,894,808) through June 2016. This amount reduces the
18 under-collection amount in Column L, resulting in a net under-collection of
19 $1,615,003 as shown in Column P. This (over)/under-collection computation
20 shown in Column L will continue and the balance will change each month
21 from July 2016 forward until such time that the Commission issues a final

[3] The interim bridge adjustment rate expired on June 30, 2016.

order in this docket approving the final 2015 revenue requirement and fixed cost rate.

Q. Has NorthWestern computed the current net difference between revenues collected from customers based on interim bridge rates and the updated revenue requirements for South Bear Paw (Devon)?

A. Yes. Refer to Exhibit__(PJD-7). The bridge rates used to bill customers during the interim period are shown in Column C. Column D reflects the amount of Dkts billed customers for each of the months that the bridge has been in place and Column F is the dollar amount billed customers. Column H reflects the updated fixed cost unit rates derived from the revenue requirements computed in Exhibits 4-5. Column J is the updated fixed cost unit rates multiplied by the billed volumes in Column D and shows the revenues that should be collected from customers. Column L shows the over-collection amount. From December 2013 through July 2016 there has been an over-collection of ($3,215,086) from customers. Column N reflects the first interim bridge adjustment per Commission Order No. 7282d ¶¶ 42 and 43 in Docket Nos. D2013.5.34 and D2014.5.47. This interim bridge[4] adjustment totals $1,671,275 through June 2016. Column P reflects the second interim adjustment based on a Stipulation between NorthWestern and the MCC in Docket No. D2014.7.59, Order No. 7421b. This interim bridge[5]

[4] The interim bridge adjustment rate expired on June 30, 2016.
[5] The interim bridge adjustment rate expired on June 30, 2016.

adjustment totals $1,212,012 through June 2016. The two interim adjustment amounts reduce the over-collection amount in Column L, resulting in a net over-collection of ($331,799) as shown in Column R. This (over)/under-collection computation shown in Column L will continue and the balance will change each month from July 2016 forward until such time that the Commission issues a final order in this docket approving the final 2015 revenue requirement and fixed cost rate.

Q. How does NorthWestern propose to handle the final (over)/under-collection balances from Bear Paw (NFR) and South Bear Paw (Devon)?

A. NorthWestern proposes to net the two final balances and, depending on whether the end result is an over- or an under-collection, either refund or charge the balance to customers over a one-year period. The updated rate used for 2016 is based on 2015 actual information for this presentation. NorthWestern plans on updating this rate with 2016 actual information when available.

Forecasted Revenue Requirements

Natural Gas Production Assets

Q. Has NorthWestern computed forecasted revenue requirements for Battle Creek, Bear Paw (NFR), and South Bear Paw (Devon)?

A. Yes, NorthWestern has prepared forecasted revenue requirements for years 2016-2019 as shown on Exhibit__(PJD-8), Exhibit__(PJD-9), and Exhibit__(PJD-10).

Q. How were the forecasted revenue requirements for Battle Creek, Bear Paw (NFR), and South Bear Paw (Devon) developed?

A. The forecasted revenue requirements were based on 2015 actual operating costs escalated at 2.50% each year with the exception of account 754 - compression costs from others, royalty expense, production taxes, gathering and liquid revenues, which were reduced based on the decline in production for each of the individual production assets. In addition, Bear Paw (NFR)-forecasted 2016 and 2017 revenue requirements reflected a reduction of $89,856 of rental expenses in account 754.

The rate base information was adjusted to reflect projected plant additions and retirements; book depreciation was calculated based on proposed depreciation rates, and depletion was based on forecasted production levels for each of the years. The computations of depreciation and depletion are addressed in the Lail Direct Testimony.

1 **Natural Gas Test Year 2015**

2 **Natural Gas Delivery Services Income Statement**

3 **Q. Please describe the Natural Gas Utility Income Statement,**

4 **Exhibit__(PJD-11).**

5 **A.** Exhibit__(PJD-11) sets forth the test period Natural Gas Utility Income

6 Statement for Delivery Services, which is calendar year ended December 31,

7 2015. The adjustments for known and measurable changes from 2015

8 actuals are shown column-by-column to derive the test period cost of service.

9

10 **Q. Please describe each column on Exhibit__(PJD-11).**

11 **A.** Each column is described as follows:

12 **Income Statement – Actual 12 Months ended December 2015**

13 Column C Natural Gas Utility

14 Column D Supply Function

15 Column E Natural Gas Transmission, Distribution & Storage Utility

16 **Test Period Adjustments**

17 Column F Revenue and Revenue Related Adjustment

18 Column G Sales and Administrative and General Adjustment

19 Column H Labor Adjustment

20 Column I One-Time Adjustment

21 Column J Corporate Allocation Adjustment

22 Column K Stipulation and Market Credits Adjustment

23 Column L Amortization Adjustment

Column M	Taxes Other Than Income Adjustment
Column N	Depreciation Adjustment
Column O	Working Capital Adjustment
Column P	Income Tax Adjustment
Column Q	Interest Synchronization Adjustment
Column R	Total Updates & Adjustments
Column S	Test Period @ Present Rates

Q. Please identify the specific columns, adjustments, or portion of those adjustments for each column on the Natural Gas Utility Income Statement, Exhibit__(PJD-11), that you will explain.

A. I will explain the following columns and adjustments:

Column C	Natural Gas Utility – Actual 2015 Expense
Column D	Supply Function – Actual 2015 Expense
Column E	Natural Gas Transmission Distribution and Storage – Actual 2015 Expense
Column F	Revenue and Revenue Related Adjustment
Column G	Sales and Administrative and General Adjustment
Column H	Labor Adjustment
Column I	One-Time Adjustment
Column L	Amortization Adjustment (Non-Rate Base Related)
Column R	Total Updates & Adjustments
Column S	Test Period @ Present Rates

Q. Please identify the specific adjustments or portion of those adjustments for each column on the Natural Gas Utility Income Statement, Exhibit__(PJD-11), that are addressed by other witnesses.

A. The adjustments that are addressed by other witnesses are as follows:

Column J	Corporate Allocation Adjustment	C. D. Lail
Column K	Stipulation and Market Credit Adjustment	C. D. Lail
Column L	Amortization Adj. (Rate Base Related)	C. D. Lail
Column M	Taxes - Other than Income Adjustment (Property Taxes)	W. M. Hitt
Column N	Depreciation Adjustment	C. D. Lail
Column O	Working Capital Adjustment	C. D. Lail
Column P	Income Tax Adjustment	W. M. Hitt
Column Q	Interest Synchronization	W. M. Hitt
Columns All	Income Taxes	W. M. Hitt

Q. Please explain Column C on the Natural Gas Utility Income Statement, Exhibit__(PJD-11).

A. This column shows the actual data based on NorthWestern's books and records for the 12-month period ended December 31, 2015, as filed in NorthWestern's annual report to the MPSC.

Q. Please explain Column D on the Natural Gas Utility Income Statement, Exhibit__(PJD-11).

1 **A.** Column D shows the Supply Function expenses for the 12-month period
2 ended December 31, 2015. This column is subtracted from Column C to
3 present the Natural Gas Utility on a Transmission, Distribution, and Storage
4 basis shown in Column E.
5
6 **Q. Does Column D on the Natural Gas Utility Income Statement eliminate**
7 **all natural gas supply related expenses including Battle Creek, Bear**
8 **Paw (NFR), and South Bear Paw (Devon) Natural Gas revenues and**
9 **expenses?**
10 **A.** Yes.
11
12 **Q. How does NorthWestern propose to handle the Natural Gas Production**
13 **2015 revenues and expenses for this filing?**
14 **A.** The revenues and expenses for each of the natural gas production assets are
15 presented in separate income statement and revenue requirement exhibits.
16
17 **Q. Please explain Column E on the Natural Gas Utility Income Statement,**
18 **Exhibit__(PJD-11).**
19 **A.** This column shows the adjusted actual income statement, which becomes the
20 basis for the test period presentation for natural gas Delivery Services.
21

Q. Please explain the revenue and revenue-related expense adjustments in Column F on the Natural Gas Utility Income Statement, Exhibit__(PJD-11).

A. I explain below the revenue-related adjustments shown on lines 10 through 14. Regarding revenue-related expense adjustments, the adjustment to Customer Accounts Expense is made to normalize actual uncollectible expense to the test period level. The test period amount is based on the three-year average uncollectible expense for the 12-month periods ended December 2013 through December 2015 for the residential and commercial customer classes.

The adjustment to Administrative and General ("A&G") Expense is made to remove Universal System Benefits ("USB") charges for the test period. These expenses are recovered through a separate USB tariff and are not included in this filing.

The adjustment to Taxes Other Than Income is made to adjust actual MPSC and MCC taxes to the test period level of revenues. The test period amount is calculated by multiplying the test period revenue by the MPSC and MCC tax rates effective on October 1, 2016.

Q. Please explain the adjustments shown in Column G on the Natural Gas Utility Income Statement, Exhibit__(PJD-11).

1 **A.** The adjustment to Customer Account Expense reflects a reduction in postage
2 costs. The U.S. Postal Service decreased postage rates effective April 10,
3 2016.
4
5 The adjustment to Sales Expense is made to remove non-allowable
6 advertising expense. This adjustment, required by Montana law[6], eliminates
7 advertising expense not related to conservation, safety, time of use, or
8 information about alternative sources of energy.
9
10 The adjustment to A&G Expense is made to adjust property and liability
11 insurance premiums, software maintenance agreements, and outside
12 services to their test period levels and remove non-allowable dues, and
13 contributions expenses. Also in A&G expense, fringe benefit expense is
14 adjusted to reflect 2016 projected fringe benefit amounts. The Long Term
15 Incentive Plan ("LTIP") expense has been removed from the test period. The
16 LTIP is a stock-based compensation plan. Finally, non-allowable A&G
17 expenses are removed from the test period in accordance with previous
18 Commission decisions.
19
20 **Q. Please explain the adjustments in Column H on the Natural Gas Utility**
21 **Income Statement, Exhibit__(PJD-11).**

[6] § 69-3-307, MCA (2011).

1 **A.** The labor adjustment is made to reflect test period changes in wages and
2 salaries. The determination of the test period labor expense consists of:
3 (1) Adjusting actual 2015 expense to normalize for one-time events and to
4 remove non-allowed lobbying expense[7];
5 (2) Annualizing for the incremental difference between hires and
6 terminations during 2015;
7 (3) Annualizing the adjusted 2015 labor expenses to reflect the year-end
8 wage and salary levels for a full year;
9 (4) Increasing the annualized 2015 labor expense calculated in (3) above
10 to reflect 2016 wage and salary increases;
11 (5) Adjusting Payroll Taxes to reflect test period labor changes; and
12 (6) Adjusting Labor Transfer Credits to reflect test period level.
13
14 **Q. Please explain the adjustment in Column I on the Natural Gas Utility**
15 **Income Statement, Exhibit__(PJD-11).**
16 **A.** The one-time adjustment to Customer Accounts Expense shown in Column I
17 reflects the current level of the ECIS+ billing system annual contract amount.
18
19 **Q. Please explain the adjustment in Column L on the Natural Gas Utility**
20 **Income Statement, Exhibit__(PJD-11).**

[7] Docket No. 82.8.54, Order No. 4938a, ¶ 154.

1 **A.** The adjustments to Amortization Expense, Non-Rate Base Related, are made
2 to set the expense to the test period levels. The portion of Montana Property
3 Taxes recovered through the annual MPSC tax tracker filing and Natural Gas
4 USBC are removed from the test period as they are recovered separately and
5 are not included in this filing. The Pension Differential reflects the difference
6 between Financial Accounting Standard (FAS) 87 pension expense and the
7 cash basis pension cost.
8
9 **Q. Have you prepared workpapers to support these adjustments?**
10 **A.** Yes, the detailed workpapers supporting these adjustments are contained in
11 Statement G filed with this Application.
12
13 **Q. Please explain Columns R and S, Total Updates and Adjustments, and**
14 **Test Period at Present Rates, respectively.**
15 **A.** Column R is the total of all adjustments shown in Columns F through Q;
16 Column S shows the results of applying all adjustments shown in Column R
17 to the actual 2015 actual Natural Gas Transmission, Distribution, and Storage
18 Utility data shown in Column E.
19
20 **Revenue Requirement – Delivery Services**
21 **Q. Have you prepared an exhibit showing the calculation of the revenue**
22 **requirement presented by NorthWestern in this proceeding?**

1 **A.** Yes, Exhibit__(PJD-12) reflects the calculation of the revenue requirement for
2 the Natural Gas Utility excluding natural gas production. 2015 test period
3 revenue requirement computations for the gas production assets are
4 discussed below.
5
6 **Natural Gas Income Statement – Battle Creek**
7 **Q. Please identify the Natural Gas Income Statement - Battle Creek,**
8 **Exhibit__(PJD-13).**
9 **A.** Exhibit__(PJD-13) sets forth the test period Natural Gas Utility Income
10 Statement for Battle Creek Natural Gas Production ("Battle Creek Income
11 Statement"), which is calendar year ended December 31, 2015. The
12 adjustments for known and measurable changes from actual 2015 are shown
13 column-by-column to derive the test period cost of service.
14
15 **Q. Please describe each column on Exhibit__(PJD-13).**
16 **A.** Each column is described as follows:
17 **Income Statement – Actual 12 Months ended December 2015**
18 Column C Battle Creek
19 Column D Battle Creek Variable
20 Column E Battle Creek Fixed
21 **Test Period Adjustments**
22 Column F Revenue and Revenue Related Adjustment
23 Column G Sales and Administrative and General Adjustment

Column H	Labor Adjustment
Column I	One-Time Adjustment
Column J	Depreciation and Depletion Adjustment
Column K	Amortization Adjustment
Column L	Allocation of Gas Production Administration
Column M	Taxes Other Than Income Adjustment
Column N	Working Capital Adjustment
Column O	Income Tax Adjustment
Column P	Interest Synchronization Adjustment
Column Q	Total Updates & Adjustments
Column R	Test Period @ Present Rates

Q. Please identify the specific columns, adjustments, or portion of those adjustments for each column on the Battle Creek Income Statement, Exhibit__(PJD-13), that you will explain.

A. I will explain the following columns and adjustments:

Column C	Battle Creek – Actual 2015 Expense
Column D	Battle Creek Variable – Actual 2015 Expense
Column E	Battle Creek Fixed – Actual 2015 Expense
Column F	Revenue and Revenue Related Adjustment
Column G	Sales and Administrative and General Adjustment
Column H	Labor Adjustment
Column I	One-Time Adjustment

Column K	Amortization Adjustment
Column P	Total Updates & Adjustments
Column Q	Test Period @ Present Rates

Q. Please identify the specific adjustments or portion of those adjustments for each column on the Battle Creek Income Statement, Exhibit__(PJD-13), that are addressed by other witnesses.

A. The adjustments that are addressed by other witnesses are as follows:

Column J	Depreciation and Depletion Adjustment	C. D. Lail
Column L	Allocation of Gas Production Administration	C. D. Lail
Column M	Taxes - Other than Income Adjustment (Property Taxes)	W. M. Hitt
Column N	Working Capital Adjustment	C. D. Lail
Column O	Income Tax Adjustment	W. M. Hitt
Column P	Interest Synchronization	W. M. Hitt
Columns All	Income Taxes	W. M. Hitt

Q. Please explain Column C on the Battle Creek Income Statement, Exhibit__(PJD-13).

A. This column shows the actual data based on NorthWestern's books and records for the 12-month period ended December 31, 2015, as filed in NorthWestern's annual report to the MPSC.

Q. Please explain Column D on the Battle Creek Income Statement, Exhibit__(PJD-13).

A. Column D shows the variable[8] expenses for the 12-month period ended December 31, 2015. This column is subtracted from Column C to present the Battle Creek Fixed costs shown in Column E.

Q. Please explain Column E on the Battle Creek Income Statement, Exhibit__(PJD-13).

A. This column shows the adjusted actual income statement, which becomes the basis for the test period presentation for Battle Creek.

Q. Please explain the revenue and revenue-related expense adjustments in Column F on the Battle Creek Income Statement, Exhibit__(PJD-13).

A. I explain below the revenue-related adjustments shown on lines 10 through 14.

The adjustment to Taxes Other Than Income is made to adjust actual MPSC and MCC taxes to the test period level of revenues. The test period amount is calculated by multiplying the test period revenue by the MPSC and MCC tax rates effective on October 1, 2016.

[8] Variable expenses include production taxes and royalty expenses, which are recovered through the natural gas supply tracker filing and are not part of the fixed costs.

1 **Q. Please explain the adjustments shown in Column G on the Battle Creek**
2 **Income Statement, Exhibit__(PJD-13).**
3 **A.** The adjustment to A&G Expense is made to adjust the injuries and damages
4 insurance premiums to their test period level.
5
6 **Q. Please explain the adjustments in Column H on the Battle Creek Income**
7 **Statement, Exhibit__(PJD-13).**
8 **A.** The labor adjustment is made to reflect test period changes in wages and
9 salaries. The determination of the test period labor expense consists of:
10 (1) Adjusting actual 2015 expense to normalize for one-time events and to
11 remove non-allowed lobbying expense[9];
12 (2) Annualizing for the incremental change between hires and terminations
13 during 2015;
14 (3) Annualizing the adjusted 2015 labor expenses to reflect the year-end
15 wage and salary levels for a full year;
16 (4) Increasing the annualized 2015 labor expense calculated in (3) above
17 to reflect 2016 wage and salary increases;
18 (5) Adjusting Payroll Taxes to reflect test period labor changes; and
19 (6) Adjusting Labor Transfer Credits to reflect test period level.
20

[9] Docket No. 82.8.54, Order No. 4938a, ¶ 154.

1 **Q. Please explain the adjustment in Column I on the Battle Creek Income**
2 **Statement, Exhibit__(PJD-13).**
3 **A.** The one-time adjustment was to eliminate $847 of expense relating to a
4 capital project written off in 2015. The second adjustment was to properly
5 reclassify insurance expense of $18,375 from an O&M account to A&G
6 expense.
7
8 **Q. Please explain the adjustment in Column K on the Battle Creek Income**
9 **Statement, Exhibit__(PJD-13).**
10 **A.** This adjustment reflects a three-year amortization relating to the over-
11 collection of the MPSC and MCC tax accumulated from the previous rate
12 filing for Battle Creek.
13
14 **Q. Have you prepared workpapers to support these adjustments?**
15 **A.** Yes, the detailed workpapers supporting these adjustments are contained in
16 Statement G filed with this Application.
17
18 **Q. Please explain Columns Q and R, Total Updates and Adjustments, and**
19 **Test Period at Present Rates, respectively.**
20 **A.** Column Q is the total of all adjustments shown in Columns F through P;
21 Column R shows the results of applying all adjustments shown in Column Q
22 to the actual 2015 actual Battle Creek Fixed Cost data shown in Column E.
23

1 **Natural Gas Income Statement - Bear Paw (NFR)**

2 **Q. Please identify the Natural Gas Income Statement - Bear Paw (NFR),**

3 **Exhibit__(PJD-14).**

4 **A.** Exhibit__(PJD-14) sets forth the test period Natural Gas Utility Income

5 Statement for Bear Paw (NFR) Natural Gas Production ("Bear Paw (NFR)

6 Income Statement"), which is calendar year ended December 31, 2015. The

7 adjustments for known and measurable changes from actual 2015 are shown

8 column-by-column to derive the test period cost of service.

9

10 **Q. Please describe each column on Exhibit__(PJD-14).**

11 **A.** Each column is described as follows:

12 **Income Statement – Actual 12 Months ended December 2015**

13 Column C Bear Paw

14 Column D Bear Paw Variable

15 Column E Bear Paw Fixed

16 **Test Period Adjustments**

17 Column F Revenue and Revenue Related Adjustment

18 Column G Sales and Administrative and General Adjustment

19 Column H Labor Adjustment

20 Column I One-Time Adjustment

21 Column J Depreciation and Depletion Adjustment

22 Column K Allocation of Gas Production Administration

23 Column L Taxes – Other Than Income Adjustment

Column M	Working Capital Adjustment
Column N	Income Tax Adjustment
Column O	Interest Synchronization Adjustment
Column P	Total Updates & Adjustments
Column Q	Test Period @ Present Rates

Q. Please identify the specific columns, adjustments, or portion of those adjustments for each column on the Bear Paw (NFR) Income Statement, Exhibit__(PJD-14), that you will explain.

A. I will explain the following columns and adjustments:

Column C	Bear Paw – Actual 2015 Expense
Column D	Bear Paw Variable – Actual 2015 Expense
Column E	Bear Paw Fixed – Actual 2015 Expense
Column F	Revenue and Revenue Related Adjustment
Column G	Sales and Administrative and General Adjustment
Column H	Labor Adjustment
Column I	One-Time Adjustment
Column P	Total Updates & Adjustments
Column Q	Test Period @ Present Rates

Q. Please identify the specific adjustments or portion of those adjustments for each column on the Bear Paw (NFR) Income Statement, Exhibit__(PJD-14), that are addressed by other witnesses.

1 **A.** The adjustments that are addressed by other witnesses are as follows:

Column J	Depreciation and Depletion Adjustment	C. D. Lail
Column K	Allocation of Gas Production Administration	C. D. Lail
Column L	Taxes - Other than Income Adjustment (Property Taxes)	W. M. Hitt
Column M	Working Capital Adjustment	C. D. Lail
Column N	Income Tax Adjustment	W. M. Hitt
Column O	Interest Synchronization	W. M. Hitt
Columns All	Income Taxes	W. M. Hitt

Q. Please explain Column C on the Bear Paw (NFR) Income Statement, Exhibit__(PJD-14).

A. This column shows the actual data based on NorthWestern's books and records for the 12-month period ended December 31, 2015, as filed in NorthWestern's annual report to the MPSC.

Q. Please explain Column D on the Bear Paw (NFR) Income Statement, Exhibit__(PJD-14).

A. Column D shows the variable[10] expenses for the 12-month period ended December 31, 2015. This column is subtracted from Column C to present the Bear Paw (NFR) Fixed costs shown in Column E.

[10] Variable expenses include production taxes and royalty expenses, which are recovered through the natural gas supply tracker filing and are not part of the fixed costs.

1 **Q. Please explain Column E on the Bear Paw (NFR) Utility Income**
2 **Statement, Exhibit__(PJD-14).**
3 **A.** This column shows the adjusted actual income statement, which becomes the
4 basis for the test period presentation for Bear Paw (NFR).
5
6 **Q. Please explain the revenue and revenue-related expense adjustments in**
7 **Column F on the Bear Paw (NFR) Income Statement, Exhibit__(PJD-14).**
8 **A.** I explain below the revenue-related adjustments shown on lines 10 through
9 14.
10
11 The adjustment to Taxes Other Than Income is made to adjust actual MPSC
12 and MCC taxes to the test period level of revenues. The test period amount
13 is calculated by multiplying the test period revenue by the MPSC and MCC
14 tax rates effective on October 1, 2016.
15
16 **Q. Please explain the adjustments shown in Column G on the Bear Paw**
17 **(NFR) Income Statement, Exhibit__(PJD-14).**
18 **A.** The adjustment to A&G Expense is made to adjust the injuries and damages
19 insurance premiums to their test period level.
20
21 **Q. Please explain the adjustments in Column H on the Bear Paw (NFR)**
22 **Income Statement, Exhibit__(PJD-14).**

1 **A.** The labor adjustment is made to reflect test period changes in wages and
2 salaries. The determination of the test period labor expense consists of:
3 (1) Adjusting actual 2015 expense to normalize for one-time events and to
4 remove non-allowed lobbying expense[11];
5 (2) Annualizing for the incremental change between hires and terminations
6 during 2015;
7 (3) Annualizing the adjusted 2015 labor expenses to reflect the year-end
8 wage and salary levels for a full year;
9 (4) Increasing the annualized 2015 labor expense calculated in (3) above
10 to reflect 2016 wage and salary increases;
11 (5) Adjusting Payroll Taxes to reflect test period labor changes; and
12 (6) Adjusting Labor Transfer Credits to reflect test period level.
13
14 **Q. Please explain the adjustment in Column I on the Bear Paw (NFR)**
15 **Income Statement, Exhibit__(PJD-14).**
16 **A.** The one-time adjustment was to eliminate $55,645 of expense relating to a
17 capital project written off in 2015. There is also a reduction of $89,856 to
18 compressor rent expense. The third adjustment was to properly reclassify
19 insurance expense of $45,906 from an O&M account to A&G expense.
20
21 **Q. Have you prepared workpapers to support these adjustments?**

[11] Docket No. 82.8.54, Order No. 4938a, ¶154.

A. Yes, the detailed workpapers supporting these adjustments are contained in Statement G filed with this Application.

Q. Please explain Columns P and Q, Total Updates and Adjustments, and Test Period at Present Rates, respectively.

A. Column P is the total of all adjustments shown in Columns F through O; Column Q shows the results of applying all adjustments shown in Column P to the actual 2015 actual Bear Paw (NFR) Fixed Cost data shown in Column E.

Natural Gas Income Statement - South Bear Paw (Devon)

Q. Please identify the Natural Gas Income Statement - South Bear Paw (Devon), Exhibit__(PJD-15).

A. Exhibit__(PJD-15) sets forth the test period Natural Gas Utility Income Statement for South Bear Paw (Devon) Natural Gas Production ("South Bear Paw (Devon) Income Statement"), which is calendar year ended December 31, 2015. The adjustments for known and measurable changes from actual 2015 are shown column-by-column to derive the test period cost of service.

Q. Please describe each column on Exhibit__(PJD-15).

A. Each column is described as follows:

Income Statement – Actual 12 Months ended December 2015

Column C South Bear Paw

Column D	South Bear Paw Variable
Column E	South Bear Paw Fixed

Test Period Adjustments

Column F	Revenue and Revenue Related Adjustment
Column G	Sales and Administrative and General Adjustment
Column H	Labor Adjustment
Column I	One-Time Adjustment
Column J	Depreciation and Depletion Adjustment
Column K	Allocation of Gas Production Administration
Column L	Taxes – Other Than Income Adjustment
Column M	Working Capital Adjustment
Column N	Income Tax Adjustment
Column O	Interest Synchronization Adjustment
Column P	Total Updates & Adjustments
Column Q	Test Period @ Present Rates

Q. Please identify the specific columns, adjustments, or portion of those adjustments for each column on the South Bear Paw (Devon) Income Statement, Exhibit__(PJD-15), that you will explain.

A. I will explain the following columns and adjustments:

Column C	South Bear Paw – Actual 2015 Expense
Column D	South Bear Paw Variable – Actual 2015 Expense
Column E	South Bear Paw Fixed – Actual 2015 Expense

Column F	Revenue and Revenue Related Adjustment
Column G	Sales and Administrative and General Adjustment
Column H	Labor Adjustment
Column I	One-Time Adjustment
Column P	Total Updates & Adjustments
Column Q	Test Period @ Present Rates

Q. Please identify the specific adjustments or portion of those adjustments for each column on the South Bear Paw (Devon) Utility Income Statement, Exhibit__(PJD-15), that are addressed by other witnesses.

A. The adjustments that are addressed by other witnesses are as follows:

Column J	Depreciation and Depletion Adjustment	C. D. Lail
Column K	Allocation of Gas Production Administration	C. D. Lail
Column L	Taxes - Other than Income Adjustment (Property Taxes)	W. M. Hitt
Column M	Working Capital Adjustment	C. D. Lail
Column N	Income Tax Adjustment	W. M. Hitt
Column O	Interest Synchronization	W. M. Hitt
Columns All	Income Taxes	W. M. Hitt

Q. Please explain Column C on the South Bear Paw (Devon) Income Statement, Exhibit__(PJD-15).

1 **A.** This column shows the actual data based on NorthWestern's books and
2 records for the 12-month period ended December 31, 2015, as filed in
3 NorthWestern's annual report to the MPSC.
4
5 **Q. Please explain Column D on the South Bear Paw (Devon) Income**
6 **Statement, Exhibit__(PJD-15).**
7 **A.** Column D shows the variable[12] expenses for the 12-month period ended
8 December 31, 2015. This column is subtracted from Column C to present the
9 South Bear Paw Fixed costs shown in Column E.
10
11 **Q. Please explain Column E on the South Bear Paw (Devon) Income**
12 **Statement, Exhibit__(PJD-15).**
13 **A.** This column shows the adjusted actual income statement, which becomes the
14 basis for the test period presentation for South Bear Paw.
15
16 **Q. Please explain the revenue and revenue-related expense adjustments in**
17 **Column F on the South Bear Paw (Devon) Income Statement,**
18 **Exhibit__(PJD-15).**
19 **A.** I explain below the revenue-related adjustments shown on lines 10 through
20 14.
21

[12] Variable expenses include production taxes and royalty expenses, which are recovered through the natural gas supply tracker filing and are not part of the fixed costs.

The adjustment to Taxes Other Than Income is made to adjust actual MPSC and MCC taxes to the test period level of revenues. The test period amount is calculated by multiplying the test period revenue by the MPSC and MCC tax rates effective on October 1, 2016.

Q. Please explain the adjustments shown in Column G on the South Bear Paw (Devon) Income Statement, Exhibit__(PJD-15).

A. The adjustment to A&G Expense is made to adjust the injuries and damages insurance premiums to their test period level.

Q. Please explain the adjustments in Column H on the South Bear Paw (Devon) Income Statement, Exhibit__(PJD-15).

A. The labor adjustment is made to reflect test period changes in wages and salaries. The determination of the test period labor expense consists of:

(1) Adjusting actual 2015 expense to normalize for one-time events and to remove non-allowed lobbying expense[13];

(2) Annualizing for the incremental change between hires and terminations during 2015;

(3) Annualizing the adjusted 2015 labor expenses to reflect the year-end wage and salary levels for a full year;

[13] Docket No. 82.8.54, Order No. 4938a, ¶154.

(4) Increasing the annualized 2015 labor expense calculated in (3) above to reflect 2016 wage and salary increases;

(5) Adjusting Payroll Taxes to reflect test period labor changes; and

(6) Adjusting Labor Transfer Credits to reflect test period level.

Q. Please explain the adjustment in Column I on the South Bear Paw (Devon) Income Statement, Exhibit__(PJD-15).

A. The one-time adjustment was to eliminate $17,485 of expense relating to a capital project written off in 2015. There was also an adjustment to eliminate road and trail damage expense of $61,835 relating to 2014 that was paid and expensed in 2015. Finally, an adjustment was made to properly reclassify insurance expense of $143,835 from an O&M account to A&G expense.

Q. Have you prepared workpapers to support these adjustments?

A. Yes, the detailed workpapers supporting these adjustments are contained in Statement G filed with this Application.

Q. Please explain Columns P and Q, Total Updates and Adjustments, and Test Period at Present Rates, respectively.

A. Column P is the total of all adjustments shown in Columns F through O; Column Q shows the results of applying all adjustments shown in Column P to the actual 2015 actual South Bear Paw (Devon) Fixed Cost data shown in Column E.

1 **Production Administration Income Statement**

2 **Q. Please identify the Natural Gas Income Statement – Production**

3 **Administration, Exhibit__(PJD-16).**

4 **A.** Exhibit__(PJD-16) sets forth the test period Natural Gas Utility Income

5 Statement for Production Administration, which is calendar year ended

6 December 31, 2015. The adjustments for known and measurable changes

7 from actual 2015 are shown column-by-column to derive the test period cost

8 of service.

9

10 **Q. Please describe each column on Exhibit__(PJD-16).**

11 **A.** Each column is described as follows:

12 **Income Statement – Actual 12 Months ended December 2015**

13 Column C Production Administration

14 **Test Period Adjustments**

15 Column D Sales and Administrative and General Adjustment

16 Column E Labor Adjustment

17 Column F One-Time Adjustment

18 Column G Corporate Allocations Adjustment

19 Column H Depreciation Adjustment

20 Column I Amortization Adjustment

21 Column J Income Tax Adjustment

22 Column K Interest Synchronization Adjustment

23 Column L Total Updates & Adjustments

Column M	Test Period @ Present Rates
Column O	Battle Creek
Column P	Bear Paw
Column Q	South Bear Paw
Column R	HPC Remaining Balance

Q. Please identify the specific columns, adjustments, or portion of those adjustments for each column on the Production Administration Income Statement, Exhibit__(PJD-16), that you will explain.

A. I will explain the following columns and adjustments:

Column C	Production Administration
Column D	Sales and Administrative and General Adjustment
Column E	Labor Adjustment
Column F	One-Time Adjustment
Column I	Amortization Adjustment
Column L	Total Updates & Adjustments
Column M	Test Period @ Present Rates

Q. Please identify the specific adjustments or portion of those adjustments for each column on the Production Administration Utility Income Statement, Exhibit__(PJD-16), that are addressed by other witnesses.

A. The adjustments that are addressed by other witnesses are as follows:

Column G	Corporate Allocations Adjustment	C. D. Lail

Column H	Depreciation Adjustment	C. D. Lail
Column J	Income Tax Adjustment	W. M. Hitt
Column K	Interest Synchronization Adjustment	W. M. Hitt
Column M	Battle Creek	C. D. Lail
Column N	Bear Paw	C. D. Lail
Column O	South Bear Paw	C. D. Lail
Column P	HPC Remaining Balance	C. D. Lail
Columns All	Income Taxes	W. M. Hitt

Q. Please explain Column C on the Production Administration Income Statement, Exhibit__(PJD-16).

A. This column shows the actual data based on NorthWestern's books and records for the 12-month period ended December 31, 2015, as filed in NorthWestern's annual report to the MPSC.

Q. Please explain Column D on the Production Administration Income Statement, Exhibit__(PJD-16).

A. The adjustment to Customer Account Expense reflects a reduction in postage costs. The U.S. Postal Service decreased postage rates effective April 10, 2016.

1 The adjustment to Sales Expense is made to remove non-allowable
2 advertising expense. This adjustment, required by Montana law[14], eliminates
3 advertising expense not related to conservation, safety, time of use, or
4 information about alternative sources of energy.
5
6 The adjustment to A&G Expense is made to adjust property and liability
7 insurance premiums, software maintenance agreements, and outside
8 services to their test period levels and remove non-allowable dues, and
9 contributions expenses. Also in A&G expense, fringe benefit expense is
10 adjusted to reflect 2016 projected fringe benefit amounts. The Long Term
11 Incentive Plan ("LTIP") expense of has been removed for the test period. The
12 LTIP is a stock-based compensation plan. Finally, non-allowable A&G
13 expenses are removed from the test period in accordance with previous
14 Commission decisions[15].
15
16 **Q. Please explain the adjustments in Column E on the Production**
17 **Administration Income Statement, Exhibit__(PJD-16).**
18 **A.** The labor adjustment is made to reflect test period changes in wages and
19 salaries. The determination of the test period labor expense consists of:

[14] § 69-3-307, MCA (2011).
[15] Docket No. 88.6.15, Order No. 5360d and Docket Nos. 84.11.71, 84.10.64 and 83.9.67, Order No. 5113b.

(1) Adjusting actual 2015 expense to normalize for one-time events and to remove non-allowed lobbying expense[16];

(2) Annualizing for the incremental change between hires and terminations during 2015;

(3) Annualizing the adjusted 2015 labor expenses to reflect the year-end wage and salary levels for a full year;

(4) Increasing the annualized 2015 labor expense calculated in (3) above to reflect 2016 wage and salary increases;

(5) Adjusting Payroll Taxes to reflect test period labor changes; and

(6) Adjusting Labor Transfer Credits to reflect test period level.

Q. Please explain the adjustment in Column F on the Production Administration Income Statement, Exhibit__(PJD-16).

A. The one-time adjustment to Customer Accounts Expense shown in Column F reflects the current level of the ECIS+ billing system annual contract amount.

Q. Please explain the adjustment in Column I on the Production Administration Income Statement, Exhibit__(PJD-16).

A. The adjustments to Amortization Expense, Non-Rate Base Related, are made to set the expense to the test period levels. The Pension Differential reflects

[16] Docket No. 82.8.54, Order No. 4938a, ¶154.

the difference between Financial Accounting Standard (FAS) 87 pension expense and the cash basis pension cost.

Q. Have you prepared workpapers to support these adjustments?

A. Yes, the detailed workpapers supporting these adjustments are contained in Statement G filed with this Application.

Q. Please explain Columns L and M, Total Updates and Adjustments, and Test Period at Present Rates, respectively.

A. Column L is the total of all adjustments shown in Columns D through K; Column L shows the results of applying all adjustments shown in Column K to the actual 2015 actual Production Administration data shown in Column C.

Revenue Requirement - Natural Gas Production Assets

Q. Have you prepared an exhibit showing the calculation of the revenue requirements for the natural gas production assets presented by NorthWestern in this proceeding?

A. Yes, Exhibit__(PJD-17) reflects the calculation of test period revenue requirements for the Battle Creek, Bear Paw (NFR) and South Bear Paw (Devon) natural gas production assets.

1 **Natural Gas Operating Revenues – Delivery Services**

2 **Q. Please describe the Natural Gas Utility Delivery Services operating**
3 **revenues exhibit.**

4 **A.** The natural gas delivery services operating revenues shown on
5 Exhibit__(PJD-18) page 1 reflect the 2015 actual billing determinants and
6 operating revenue information (customers, demand, dekatherms, and
7 revenues) in Columns B through E. The actual revenues include only
8 distribution, transmission and storage revenues. The pro forma test period
9 operating revenue information is shown in Columns L through O. The pro
10 forma test period revenues utilize current base rates, the derivation of which
11 is described below, and normalized loads and customer counts. Column P
12 shows the revenues at the proposed rate design. Columns Q and R show the
13 Revenue Requirement increase in both dollar and percentage terms for each
14 customer class.

15

16 **Q. Were there any other revenue adjustments to the test period?**

17 **A.** Yes, the DBU Transportation test period revenues reflect the expiration of the
18 discounted contract rate with Montana Tech effective on September 2017.
19 The current contract rate is $3.068/Maximum Daily Delivery Quantity
20 ("MDDQ") and the test period rate for this service is $7.739992/MDDQ. This
21 change results in an additional natural gas distribution charge of $22,482 per
22 year based on Montana Tech's MDDQ of 401 Dkt per day.

23

Natural Gas Customer Count

Q. Were there any adjustments to the customer count for the test period?

A. No. The customer count used was the 2015 actual number of customers. The customer count information is reflected on Exhibit__(PJD-18), pages 2 and 3.

Normalized Natural Gas Loads

Q. Were there any adjustments made to the 2015 actual load information?

A. Yes. The core loads have been adjusted to reflect weather normalized test period loads based upon the MPSC-approved methodology established in prior rate cases. That methodology applies a normalized weather adjustment based on 15 years of weather data to the test period load information. The normalized load information is reflected on Exhibit__(PJD-18), page 4. The adjustments result in an increase to actual 2015 loads and revenues for core customers and non-core customers.

Miscellaneous Natural Gas Revenues

Q. What adjustments have been made to Miscellaneous Revenues?

A. The miscellaneous low-income discount revenues were normalized to zero. The low-income discount is eliminated because the amount is recovered through USB charges.

1 **Derivation of Natural Gas Delivery Services Test Period Revenues**

2 **Q. What rates were applied to derive the pro-forma test period revenues for**
3 **delivery services?**

4 **A.** The pro-forma test period revenues are based upon the most recent rates
5 established by the Commission, in this case the natural gas rates developed
6 in Final Order No. 7451a entered in MPSC Docket No. D2015.10.81,
7 NorthWestern's most recent filing for the Automatic Rate Adjustment and
8 Tracking for Taxes and Fees. Final Order No. 7451a approved a rate increase
9 of $980,429 or 0.84%. However, that amount included the amortization of the
10 2015 Deferred Balance in the amount of $1,238,613. The rates shown on
11 Exhibit__(PJD-18), pages 6 and 7 have been adjusted to remove the rate
12 component associated with 2015 Deferred Balance as reflected in this filing.
13

14 **Q. Why did you exclude the rate component associated with the Deferred**
15 **Balance from the rates?**

16 **A.** The amortization of the deferred balance is due to the tracking of taxes and
17 fees from the prior period and should not be used in a general rate case to
18 establish rates on a prospective basis. Therefore, it was removed from the
19 test period.
20

21 **Natural Gas Transportation Adjustment Clause**

22 **Q. What is NorthWestern's proposal regarding the Gas Transportation**
23 **Adjustment Clause ("GTAC") Mechanism in this filing?**

1 **A.** NorthWestern proposes to continue to utilize the GTAC Mechanism to track
2 the difference between the revenues shown in the test period and actual
3 Interruptible and Off-system transportation sales. NorthWestern proposes to
4 reset the current GTAC basis utilized in NorthWestern's natural gas default
5 supply tracking mechanism, which is based on the last general rate case, to
6 the level reflected in the test period as shown on Exhibit__(PJD-18) page 1,
7 Column O, lines 32, 36, 42, and 45. The GTAC mechanism was initially
8 approved in Order No. 5474c in Docket No. 90.1.1 on October 3, 1991.
9 NorthWestern, as well as its predecessor, MPC, has used this mechanism
10 since it was approved.
11
12 **Derivation of Natural Gas Production Assets Test Period Revenues**
13 **Q. Please describe the Natural Gas Production Assets test period revenues**
14 **exhibit.**
15 **A.** The natural gas operating production revenues are shown on Exhibit__(PJD-
16 19), page 1. The Battle Creek test period revenues are based on a rate of
17 $0.1237/Dkt, which was approved in Order No. 7249e in Docket No.
18 D2012.9.94. The Bear Paw (NFR) and South Bear Paw (Devon) test period
19 revenues are based on bridge rates per Commission Order No. 7282d, ¶ 41
20 in Docket Nos. D2013.5.34 and D2014.5.47. The Bear Paw (NFR) and South
21 Bear Paw (Devon) rates are $0.1700/Dkt and $0.7823/Dkt, respectively.
22 These revised bridge rates were initially part of the overall natural gas supply
23 rate on November 1, 2015.

1 **Proposed Natural Gas Rates**

2 **Q. Please describe the process used by NorthWestern to derive the**
3 **proposed natural gas rates.**

4 **A.** NorthWestern's current proposed rates are based on a uniform basis since
5 the allocated cost of service and rate design has been bifurcated this initial
6 filing.

7

8 **Q. What is NorthWestern's proposal for implementing its proposed natural**
9 **gas base rates?**

10 **A.** As presented in NorthWestern's Application for an Interim Rate Adjustment
11 that accompanies this filing, NorthWestern proposes that interim rates be
12 implemented on an expedited basis to allow NorthWestern to recover
13 sufficient revenues to cover the costs associated with providing its customers
14 safe and reliable service.

15

16 **Q. Does this conclude your testimony?**

17 **A.** Yes, it does.

	A	B	C	D	E	F
1		**NorthWestern Energy**				
2		**Bear Paw (NFR) Natural Gas Properties**				
3		**Docket No. D2016.9.68**				
4						
5		**Revenue Requirement Analysis**				
6						
7						
8				**31-Dec-13**		
9		**Description**		Year End		13-Month Ave
10		**Utility Plant in Service**				
11		Bear Paw		$ 15,921,436		$ 16,604,400
12						
13		Total Plant in Service		$ 15,921,436		$ 16,604,400
14						
15		Less:				
16		Accumulated Depreciation & Depletion		$ 1,997,102		$ 1,064,401
17		Total Net Plant		$ 13,924,334		$ 15,540,000
18						
19		Less: Customer Contributed Capital				
20		Deferred Income Taxes				
21		Accelerated Tax Depreciation/Depletion		$ (367,111)		$ (182,268)
22						
23		Total Customer Contributed Capital		$ (367,111)		$ (182,268)
24						
25		Total Year End Rate Base		$ 14,291,445		$ 15,722,267
26						
27		**Rate of Return**				7.63%
28						
29		***Authorized Return (Avg. Rate Base * Rate of Return)***				$ 1,199,609
30						
31		***Cost of Service:***				
32		Operation & Maintenance Expenses		$ 3,940,082		
33		Depreciation Expense		89,458		
34		Depletion Expense		1,930,809		
35		Property & Other Taxes		417,175		
36		MPSC & MCC Revenue Tax (Order 7313 & 7314)	0.53%	26,274		
37		Misc. Revenues		(765,451)		
38		Non-operating Revenues		(453,571)		
39		Gathering Revenues		(957,811)		
40		Farm Tap Revenues		(9,839)		
41		Deferred Income Taxes		(191,365)		
42		Current Income Taxes		701,933		
43		***Total Cost of Service***				$ 4,727,695
44						
45		***Less Variable Costs:***				
46		Production Taxes		$ 225,909		
47		Royalty Expense		744,087		
48		***Total Variable Cost of Service***				969,996
49						
50		**Total Fixed Revenue Requirement (Ln 29 + Ln 43 - Ln 48)**				$ 4,957,308
51						
52		**2013 Test Period Normalized Load (Dkt)**				19,659,839
53						
54		**Fixed Cost Unit Rate Year 2013**		(Ln 50 / Ln 52)		$ 0.2522

	A	B	C	D	E	F
55						
56						
57						
58		***Income Tax Computation:***	**Rate**			
59		Revenues		$ 4,957,308		
60		Operating Expenses		3,195,996		
61		Miscellaneous Revenues		(765,451)		
62		Non-operating Revenues		(453,571)		
63		Gathering Revenues		(957,811)		
64		Farm Tap Revenues		(9,839)		
65		Property & Other Taxes		191,266		
66		MPSC & MCC Revenue Tax		26,274		
67		Tax Depreciation/Depletion		1,473,510		
68		Montana Corporate Income Tax		120,293		
69		Interest Expense (Based on Avg. Rate Base)	3.02%	474,812		
70		Federal Taxable Income		$ 1,661,829		
71						
72		Federal Income Tax @ 35%	35.00%	581,640		
73						
74		Federal Current Tax Expense		581,640		
75						
76		Federal Taxable Income		$ 1,661,829		
77		Montana Corporate Income Tax		120,293		
78		Montana Corporate Taxable		$ 1,782,122		
79						
80		Montana Corporate Income Tax @ 6.75%	6.75%	120,293		
81						
82		Montana Current Tax Expense		120,293		
83						
84		Total Current Income Tax Expense		$ 701,933		
85						
86		***Deferred Income Tax Computation:***	**Rate**			
87		***Accelerated Tax Depreciation/Depletion***				
88		Tax Depreciation/Depletion		$ 1,473,510		
89		Less Book Depreciation/Depletion		2,020,267		
90		Net Deferred Taxable Income		$ (546,758)		
91		Federal Income Tax Rate		35%		
92		Federal Deferred Income Tax Expense-Accelerated Tx Depr/Depl		$ (191,365)		

	A	B	C	D	E	F
1		NorthWestern Energy				
2		Bear Paw (NFR) Natural Gas Properties				
3						
4		Tax Depreciation/Depletion Summary				
5						
6						
7		Book Basis - EOY	$13,924,334			
8		Tax Basis - EOY	$14,973,221			
9		Deferred Tax - EOY	$ (1,048,887)			
10		Federal Tax Rate	35%			
11		Deferred Tax Liab (Asset) - EOY	$ (367,111)			
12						
13		Book Basis - BOY	$16,918,824			
14		Tax Basis - BOY	$16,911,465			
15		Deferred Tax - BOY	$ 7,359			
16		Federal Tax Rate	35%			
17		Deferred Tax Liab (Asset) - BOY	$ 2,575			

	A	B	C	D	E	F	G
1				**NorthWestern Energy**			
2				**Bear Paw (NFR) Natural Gas Properties**			
3							
4				**Capital Structure**			
5							
6							
7							
8							
9				**Percent**	**Rate of**		
10		**Capital Structure**	**Rate**	**Capitalization**	**Return**		
11		Equity	10.00%	46.08%	4.61%		
12		Debt	5.60%	53.92%	3.02%		
13							
14		Total		100.00%	7.63%		

	A	B	C	D	E	F	G	H
1			NorthWestern Energy					
2			Bear Paw (NFR) Natural Gas Properties					
3								
4			Income Statement					
5			12 Months Actual Ended December 2013			Normalizing		
6				2013 Actuals		Adjustments		Test Period
7		OPERATIONS & MAINTENANCE:						
8			Production Expenses					
9								
10		Production & Gathering-Operation						
11		750	Supervision & Engineering	21,073.86				21,073.86
12		751	Maps & Records	-				-
13		752	Gas Wells Expenses	715,626.84				715,626.84
14		753	Field Lines Expenses	-				-
15		754	Field Compressor Station Expense	1,438,117.59				1,438,117.59
16		755	Field Comp. Station Fuel & Power	-				-
17		756	Field Meas. & Reg. Station Expense	(817.42)				(817.42)
18		757	Dehydration Expense	7,475.29				7,475.29
19		758	Gas Well Royalties	744,086.68				744,086.68
20		759	Other Expenses	648,785.98				648,785.98
21		760	Rents	178,324.05				178,324.05
22		Total Oper. Production & Gathering		3,752,672.87		-		3,752,672.87
23		Production & Gathering-Maintenance						
24		761	Supervision and Engineering	-				-
25		762	Structures and Improvements	-				-
26		763	Producing Gas Wells	14,885.51				14,885.51
27		764	Field Lines	1,867.66				1,867.66
28		765	Field Compressor Station Equipment	149,734.38				149,734.38
29		766	Field Measuring and Regulating Station Equipment	328.47				328.47
30		767	Purification Equipment	71.95				71.95
31		768	Drilling and Cleaning Equipment	-				-
32		769	Other Equipment	20,521.39				20,521.39
33		Total Maint. Production & Gathering		187,409.36		-		187,409.36
34		Total Production & Gathering Expenses		3,940,082.23		-		3,940,082.23
35								
36		Admin. & General - Operation						
37		920-935	Corporate Allocations	-				-
38				-				-
39		Total Operation-Admin. & General		-		-		-
40		Total Admin. & General Expenses		-		-		-
41								
42		TOTAL OPER. & MAINT. EXPENSES		3,940,082.23		-		3,940,082.23
43								
44		408.1	Payroll Taxes	50,307.41				50,307.41
45			Vehicle Taxes	3,348.62				3,348.62
46			Total Labor & Vehicle Taxes	53,656.03		-		53,656.03
47								
48								
49		408.1	Property Taxes	137,609.94				137,609.94
50			Production Taxes	225,908.96				225,908.96
51			MPSC/MCC Taxes	-				-
52			Other Taxes	-				-
53								
54		457110	Non-operating	453,570.77				453,570.77
55		469610	Miscellaneous Revenues	765,451.41				765,451.41
56		459100	Gathering Revenues	957,810.60				957,810.60
57		492200	Liquid Sales	9,838.61				9,838.61
58				2,186,671.39		-		2,186,671.39

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1				NORTHWESTERN ENERGY - MONTANA GAS PLANT BEAR PAW - 2013 ACCRUAL CALCULATION										
2														
3				Plant Balance		Depr/Depl Reserve		OC-D		Accrual		TOTAL		
4				12/31/2012		12/31/2012		12/31/2012		%		2013 Accrual		2013 Depletion
5														
6														
7														
8	G325	Land		435,535.31		0.00		435,535.31		0.0000		0		
9	G325.2	Gas Leaseholds		10,556,360.00		17,519.04		10,538,840.96		Depletion				1,544,984
10	G330	Producing Gas Wells - Construction		1,375,890.00		2,283.39		1,373,606.61		Depletion				192,182
11	G331	Producing Gas Wells - Equipment		1,388,303.00		2,303.99		1,385,999.01		Depletion				193,643
12	G332	Field Lines		1,573,153.60		2,327.70		1,570,825.90		0.0305		47,981		
13	G333	Field Compressor Equipment		229,309.35		2,061.83		227,247.52		0.0305		6,994		
14	G334.1	Field Measuring & Regulating Equip		479,088.87		1,739.81		477,349.06		0.0305		14,612		
15	G334.2	Field Dehydration Equip		16,983.70		101.12		16,882.58		0.0305		518		
16	G390	Structures		871,070.64		9,861.16		861,209.48		0.0211		18,380		
17	G390.6	Structure Communications		2,274.87		21.73		2,253.14		0.0234		53		
18	G392.7	Transportation - ATV's		7,358.08		390.20		6,967.88		0.1250		920		
19														
20		Total Bear Paw		16,935,327.42		38,609.97		16,896,717.45				89,458		1,930,809
21														
22														
23														
24														
25				Depletion		Depreciation		Total Expense						
26														
27		Jan		160,900.78		7,454.83		168,355.61						
28		Feb		160,900.78		7,454.83		168,355.61						
29		Mar		160,900.78		7,454.83		168,355.61						
30		Apr		160,900.78		7,454.83		168,355.61						
31		May		160,900.78		7,454.83		168,355.61						
32		Jun		160,900.78		7,454.83		168,355.61						
33		Jul		160,900.78		7,454.83		168,355.61						
34		Aug		160,900.78		7,454.83		168,355.61						
35		Sep		160,900.78		7,454.83		168,355.61						
36		Oct		160,900.78		7,454.83		168,355.61						
37		Nov		160,900.78		7,454.83		168,355.61						
38		Dec		160,900.78		7,454.83		168,355.61						
39														
40		Total		1,930,809.38		89,457.92		2,020,267.30						
41														
42	*													

	A	B	C	D	E	F	G	H	I	J	K	L	M
1			NORTHWESTERN ENERGY - MONTANA GAS OPERATIONS - 2013 BEAR PAW RATE BASE										
2								DEPR/DEPL				DEFERRED INCOME TAXES	
3						PLANT BALANCE		RESERVE		OC-D		NET ACTIVITY	ENDING BALANCE
4													
5	1		DECEMBER	2012		$ 16,935,327		$ 16,504		$ 16,918,824			$ 2,575
6													
7	2		JANUARY	2013		$ 16,934,137		$ 440,482		$ 16,493,655		$ (30,807)	$ (28,232)
8													
9	3		FEBRUARY	2013		$ 16,933,988		$ 446,490		$ 16,487,498		$ (30,807)	$ (59,039)
10													
11	4		MARCH	2013		$ 16,933,863		$ 577,521		$ 16,356,342		$ (30,807)	$ (89,846)
12													
13	5		APRIL	2013		$ 16,933,863		$ 724,126		$ 16,209,736		$ (30,807)	$ (120,653)
14													
15	6		MAY	2013		$ 16,933,863		$ 888,106		$ 16,045,757		$ (30,807)	$ (151,460)
16													
17	7		JUNE	2013		$ 16,631,547		$ 1,060,814		$ 15,570,733		$ (30,807)	$ (182,268)
18													
19	8		JULY	2013		$ 16,631,547		$ 1,220,079		$ 15,411,469		$ (30,807)	$ (213,075)
20													
21	9		AUGUST	2013		$ 16,631,547		$ 1,379,534		$ 15,252,013		$ (30,807)	$ (243,882)
22													
23	10		SEPTEMBER	2013		$ 16,655,119		$ 1,547,857		$ 15,107,262		$ (30,807)	$ (274,689)
24													
25	11		OCTOBER	2013		$ 15,890,484		$ 1,692,114		$ 14,198,370		$ (30,807)	$ (305,496)
26													
27	12		NOVEMBER	2013		$ 15,890,484		$ 1,846,483		$ 14,044,001		$ (30,807)	$ (336,303)
28													
29	13		DECEMBER	2013		$ 15,921,436		$ 1,997,102		$ 13,924,334		$ (30,807)	$ (367,111)
30													
31													
32			13 MONTH AVERAGE			$ 16,604,400		$ 1,064,401		$ 15,540,000			$ (182,268)

	A	B	C	D	E	F
1		**NorthWestern Energy**				
2		**Bear Paw (NFR) Natural Gas Properties**				
3		**Docket No. D2016.9.68**				
4						
5		**Revenue Requirement Analysis**				
6						
7						
8				**31-Dec-14**		
9		**Description**		Year End		13-Month Ave
10		**Utility Plant in Service**				
11		Bear Paw		$ 15,959,437		$ 15,950,930
12						
13		Total Plant in Service		$ 15,959,437		$ 15,950,930
14						
15		Less:				
16		Accumulated Depreciation & Depletion		$ 3,546,038		$ 2,784,315
17		Total Net Plant		$ 12,413,399		$ 13,166,615
18						
19		Less: Customer Contributed Capital				
20		Deferred Income Taxes				
21		Accelerated Tax Depreciation/Depletion		$ (656,779)		$ (511,945)
22						
23		Total Customer Contributed Capital		$ (656,779)		$ (511,945)
24						
25		Total Year End Rate Base		$ 13,070,177		$ 13,678,559
26						
27		**Rate of Return**				7.63%
28						
29		***Authorized Return (Avg. Rate Base * Rate of Return)***				$ 1,043,674
30						
31		***Cost of Service:***				
32		Operation & Maintenance Expenses		$ 3,332,781		
33		Depreciation Expense		62,189		
34		Depletion Expense		1,519,841		
35		Property & Other Taxes		463,813		
36		MPSC & MCC Revenue Tax (Order 7370 & 7371)	0.30%	13,183		
37		Misc. Revenues		(405,537)		
38		Non-operating Revenues		(225,017)		
39		Gathering Revenues		(752,185)		
40		Farm Tap Revenues		-		
41		Deferred Income Taxes		41,853		
42		Current Income Taxes		359,259		
43		***Total Cost of Service***				$ 4,410,180
44						
45		***Less Variable Costs:***				
46		Production Taxes		$ 254,708		
47		Royalty Expense		804,822		
48		***Total Variable Cost of Service***				1,059,531
49						
50		**Total Fixed Revenue Requirement (Ln 29 + Ln 43 - Ln 48)**				$ 4,394,323
51						
52		**2014 Test Period Normalized Load (Dkt)**				19,686,697
53						
54		**Fixed Cost Unit Rate Year 2014**		(Ln 50 / Ln 52)		$ 0.2232

	A	B	C	D	E	F
55						
56						
57						
58		***Income Tax Computation:***	**Rate**			
59		Revenues		$ 4,394,323		
60		Operating Expenses		2,527,959		
61		Miscellaneous Revenues		(405,537)		
62		Non-operating Revenues		(225,017)		
63		Gathering Revenues		(752,185)		
64		Farm Tap Revenues		-		
65		Property & Other Taxes		209,105		
66		MPSC & MCC Revenue Tax		13,183		
67		Tax Depreciation/Depletion		1,701,610		
68		Montana Corporate Income Tax		61,568		
69		Interest Expense (Based on Avg. Rate Base)	3.02%	413,092		
70		Federal Taxable Income		$ 850,546		
71						
72		Federal Income Tax @ 35%	35.00%	297,691		
73						
74		Federal Current Tax Expense		297,691		
75						
76		Federal Taxable Income		$ 850,546		
77		Montana Corporate Income Tax		61,568		
78		Montana Corporate Taxable		$ 912,113		
79						
80		Montana Corporate Income Tax @ 6.75%	6.75%	61,568		
81						
82		Montana Current Tax Expense		61,568		
83						
84		Total Current Income Tax Expense		$ 359,259		
85						
86		***Deferred Income Tax Computation:***	**Rate**			
87		***Accelerated Tax Depreciation/Depletion***				
88		Tax Depreciation/Depletion		$ 1,701,610		
89		Less Book Depreciation/Depletion		1,582,030		
90		Net Deferred Taxable Income		$ 119,580		
91		Federal Income Tax Rate		35%		
92		Federal Deferred Income Tax Expense-Accelerated Tx Depr/Depl		$ 41,853		

	A	B	C	D	E	F
1		NorthWestern Energy				
2		Bear Paw (NFR) Natural Gas Properties				
3						
4		Tax Depreciation/Depletion Summary				
5						
6						
7		Book Basis - EOY	$12,413,399			
8		Tax Basis - EOY	$14,289,909			
9		Deferred Tax - EOY	$ (1,876,510)			
10		Federal Tax Rate	35%			
11		Deferred Tax Liab (Asset) - EOY	$ (656,779)			
12						
13		Book Basis - BOY	$13,924,334			
14		Tax Basis - BOY	$14,973,221			
15		Deferred Tax - BOY	$ (1,048,887)			
16		Federal Tax Rate	35%			
17		Deferred Tax Liab (Asset) - BOY	$ (367,111)			

	A	B	C	D	E	F	G
1				NorthWestern Energy			
2				Bear Paw (NFR) Natural Gas Properties			
3							
4				Capital Structure			
5							
6							
7							
8							
9				Percent	Rate of		
10		Capital Structure	Rate	Capitalization	Return		
11		Equity	10.00%	46.08%	4.61%		
12		Debt	5.60%	53.92%	3.02%		
13							
14		Total		100.00%	7.63%		

	A	B	C	D	E	F	G	H
1			**NorthWestern Energy**					
2			**Bear Paw (NFR) Natural Gas Properties**					
3								
4			**Income Statement**					
5			**12 Months Actual Ended December 2014**			Normalizing		
6				2014 Actuals		Adjustments		Test Period
7		**OPERATIONS & MAINTENANCE:**						
8			**Production Expenses**					
9								
10		**Production & Gathering-Operation**						
11		750	Supervision & Engineering	18,340.77				18,340.77
12		751	Maps & Records	-				-
13		752	Gas Wells Expenses	510,596.81				510,596.81
14		753	Field Lines Expenses	2,057.09				2,057.09
15		754	Field Compressor Station Expense	2,790,200.75	(a)	($1,153,050.28)		1,637,150.47
16		755	Field Comp. Station Fuel & Power	(629,122.50)				(629,122.50)
17		756	Field Meas. & Reg. Station Expense	56,150.87				56,150.87
18		757	Dehydration Expense	56.00				56.00
19		758	Gas Well Royalties	804,822.28				804,822.28
20		759	Other Expenses	591,758.40				591,758.40
21		760	Rents	141,939.25				141,939.25
22		**Total Oper. Production & Gathering**		4,286,799.72		(1,153,050.28)		3,133,749.44
23		**Production & Gathering-Maintenance**						
24		761	Supervision and Engineering	-				-
25		762	Structures and Improvements	-				-
26		763	Producing Gas Wells	2,478.25				2,478.25
27		764	Field Lines	50,600.51				50,600.51
28		765	Field Compressor Station Equipment	133,883.15				133,883.15
29		766	Field Measuring and Regulating Station Equipment	2,624.20				2,624.20
30		767	Purification Equipment	9,706.27				9,706.27
31		768	Drilling and Cleaning Equipment	-				-
32		769	Other Equipment	(260.52)				(260.52)
33		**Total Maint. Production & Gathering**		199,031.86		-		199,031.86
34		**Total Production & Gathering Expenses**		4,485,831.58		(1,153,050.28)		3,332,781.30
35								
36		**Admin. & General - Operation**						
37		920-935	Corporate Allocations	-				-
38				-				-
39		**Total Operation-Admin. & General**		-		-		-
40		**Total Admin. & General Expenses**		-		-		-
41								
42		**TOTAL OPER. & MAINT. EXPENSES**		4,485,831.58		(1,153,050.28)		3,332,781.30
43								
44		408.1	Payroll Taxes	51,571.75				51,571.75
45			Vehicle Taxes	2,274.84				2,274.84
46			Total Labor & Vehicle Taxes	53,846.59		-		53,846.59
47								
48								
49		408.1	Property Taxes	155,257.97				155,257.97
50			Production Taxes	254,708.32				254,708.32
51			MPSC/MCC Taxes	-				-
52			Other Taxes	-				-
53								
54		457110	Non-operating	225,017.05				225,017.05
55		469610	Miscellaneous Revenues	405,537.30				405,537.30
56		459100	Gathering Revenues	752,185.25				752,185.25
57		492200	Liquid Sales	-				-
58				1,382,739.60		-		1,382,739.60
59								
60								
61			(a) Eliminate prior period adjustment relating to the effect of accounting and allocation adjustments to the					
62			natural gas tracker reflecting the proper allocation of Bear Paw (NFR) and South Bear Paw (Devon).					
63								

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	NORTHWESTERN ENERGY - MONTANA GAS PLANT BEAR PAW - 2014 ACCRUAL CALCULATION														
2															
3				Plant Balance		Depr/Depl Reserve		OC-D		Accrual		TOTAL			
4				12/31/2013		12/31/2013		12/31/2013		%		2014 Accrual		2014 Depletion	
5															
6															
7															
8	G325	Land		367,894.16		1,473.16		366,421.00		0.0000		0			
9	G325.2	Gas Leaseholds		11,060,103.47		1,540,738.89		9,519,364.58		Depletion		0		1,245,332	
10	G327	Field Compressor Structure		12,325.75		0.00		12,325.75		0.0305		376			
11	G328	Field Measuring & Regulating Structure		262,707.18		0.00		262,707.18		0.0305		8,013			
12	G330	Producing Gas Wells - Construction		1,248,226.30		191,624.24		1,056,602.06		Depletion		0		138,226	
13	G331	Producing Gas Wells - Equipment		1,234,919.05		193,164.74		1,041,754.31		Depletion		0		136,283	
14	G332	Field Lines		1,319,857.47		54,993.15		1,264,864.32		0.0305		40,256			
15	G333	Field Compressor Equipment		212,695.55		2,250.21		210,445.34		0.0305		6,487			
16	G334.1	Field Measuring & Regulating Equip		156,517.42		10,049.55		146,467.87		0.0305		4,774			
17	G334.2	Field Dehydration Equipment		15,258.49		480.43		14,778.06		0.0305		465			
18	G392.2	Transportation - Vehicles		9,322.00		736.64		8,585.36		0.0200		186			
19	G392.7	Transportation - ATV's		7,358.08		1,251.38		6,106.70		0.1250		920			
20	G394	Tools		14,251.31		339.70		13,911.61		0.0500		713			
21															
22		Total Bear Paw		15,921,436.23		1,997,102.09		13,924,334.14				62,189		1,519,841	
23															
24															
25						Normalizing									
26				Depletion		Depletion		Depreciation		Total Expense					
27															
28		Jan		133,398.25		126,653.42		5,182.44		131,835.87					
29		Feb		132,589.72		126,653.42		5,182.44		131,835.87					
30		Mar		116,422.87		126,653.42		5,182.44		131,835.87					
31		Apr		135,788.77		126,653.42		5,182.44		131,835.87					
32		May		124,458.85		126,653.42		5,182.44		131,835.87					
33		Jun		131,614.79		126,653.42		5,182.44		131,835.87					
34		Jul		121,320.88		126,653.42		5,182.44		131,835.87					
35		Aug		128,341.64		126,653.42		5,182.44		131,835.87					
36		Sep		126,386.60		126,653.42		5,182.44		131,835.87					
37		Oct		126,857.16		126,653.42		5,182.44		131,835.87					
38		Nov		121,349.48		126,653.42		5,182.44		131,835.87					
39		Dec		116,528.16		126,653.42		5,182.44		131,835.87					
40															
41		Total		1,515,057.17		1,519,841.09		62,189.30		1,582,030.39					
42															
43															
44	*														

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	NERGY - MONTANA GAS OPERATIONS - 2014 BEAR PAW RATE BASE												
2								DEPR/DEPL				DEFERRED INCOME TAXES	
3						PLANT BALANCE		RESERVE		OC-D		NET ACTIVITY	ENDING BALANCE
4													
5	1		DECEMBER	2013		$ 15,921,436		$ 1,997,102		$ 13,924,334			$ (367,111)
6													
7	2		JANUARY	2014		$ 15,921,436		$ 2,135,666		$ 13,785,770		$ (24,139)	$ (391,250)
8													
9	3		FEBRUARY	2014		$ 15,933,987		$ 2,273,502		$ 13,660,484		$ (24,139)	$ (415,389)
10													
11	4		MARCH	2014		$ 15,933,987		$ 2,388,674		$ 13,545,313		$ (24,139)	$ (439,528)
12													
13	5		APRIL	2014		$ 15,933,987		$ 2,527,686		$ 13,406,300		$ (24,139)	$ (463,667)
14													
15	6		MAY	2014		$ 15,949,275		$ 2,655,442		$ 13,293,832		$ (24,139)	$ (487,806)
16													
17	7		JUNE	2014		$ 15,970,585		$ 2,791,265		$ 13,179,319		$ (24,139)	$ (511,945)
18													
19	8		JULY	2014		$ 15,970,585		$ 2,915,902		$ 13,054,682		$ (24,139)	$ (536,084)
20													
21	9		AUGUST	2014		$ 15,970,585		$ 3,047,582		$ 12,923,002		$ (24,139)	$ (560,223)
22													
23	10		SEPTEMBER	2014		$ 15,965,596		$ 3,177,336		$ 12,788,261		$ (24,139)	$ (584,362)
24													
25	11		OCTOBER	2014		$ 15,965,596		$ 3,307,574		$ 12,658,022		$ (24,139)	$ (608,501)
26													
27	12		NOVEMBER	2014		$ 15,965,596		$ 3,432,325		$ 12,533,272		$ (24,139)	$ (632,640)
28													
29	13		DECEMBER	2014		$ 15,959,437		$ 3,546,038		$ 12,413,399		$ (24,139)	$ (656,779)
30													
31													
32			13 MONTH AVERAGE			$ 15,950,930		$ 2,784,315		$ 13,166,615			$ (511,945)

	A	B	C	D	E	F
1		**NorthWestern Energy**				
2		**Bear Paw (NFR) Natural Gas Properties**				
3		**Docket No. D2016.9.68**				
4						
5		**Revenue Requirement Analysis**				
6						
7						
8				**31-Dec-15**		
9		**Description**		Year End		13-Month Ave
10		**Utility Plant in Service**				
11		Bear Paw		$ 17,573,466		$ 16,080,164
12						
13		Total Plant in Service		$ 17,573,466		$ 16,080,164
14						
15		Less:				
16		Accumulated Depreciation & Depletion		$ 5,071,391		$ 4,287,814
17		Total Net Plant		$ 12,502,075		$ 11,792,350
18						
19		Less: Customer Contributed Capital				
20		Deferred Income Taxes				
21		Accelerated Tax Depreciation/Depletion		$ (339,401)		$ (498,090)
22						
23		Total Customer Contributed Capital		$ (339,401)		$ (498,090)
24						
25		Total Year End Rate Base		$ 12,841,476		$ 12,290,439
26						
27		**Rate of Return**				7.63%
28						
29		***Authorized Return (Avg. Rate Base * Rate of Return)***				$ 937,761
30						
31		***Cost of Service:***				
32		Operation & Maintenance Expenses		$ 2,484,592		
33		Depreciation Expense		62,228		
34		Depletion Expense		1,245,457		
35		Property & Other Taxes		269,419		
36		MPSC & MCC Revenue Tax (Order 7437 & 7438)	0.29%	11,579		
37		Misc. Revenues		(354,292)		
38		Non-operating Revenues		(30,366)		
39		Gathering Revenues		(644,388)		
40		Farm Tap Revenues		-		
41		Deferred Income Taxes		92,438		
42		Current Income Taxes		256,628		
43		***Total Cost of Service***				$ 3,393,295
44						
45		***Less Variable Costs:***				
46		Production Taxes		$ 70,985		
47		Royalty Expense		267,347		
48		***Total Variable Cost of Service***				338,332
49						
50		**Total Fixed Revenue Requirement (Ln 29 + Ln 43 - Ln 48)**				$ 3,992,723
51						
52		**2015 Test Period Normalized Load (Dkt)**				19,106,584
53						
54		**Fixed Cost Unit Rate Year 2015**		(Ln 50 / Ln 52)		$ 0.2090

	A	B	C	D	E	F
55						
56						
57						
58		***Income Tax Computation:***	**Rate**			
59		Revenues		$ 3,992,723		
60		Operating Expenses		2,217,245		
61		Miscellaneous Revenues		(354,292)		
62		Non-operating Revenues		(30,366)		
63		Gathering Revenues		(644,388)		
64		Farm Tap Revenues		-		
65		Property & Other Taxes		198,434		
66		MPSC & MCC Revenue Tax		11,579		
67		Tax Depreciation/Depletion		1,571,794		
68		Montana Corporate Income Tax		43,979		
69		Interest Expense (Based on Avg. Rate Base)	3.02%	371,171		
70		Federal Taxable Income		$ 607,566		
71						
72		Federal Income Tax @ 35%	35.00%	212,648		
73						
74		Federal Current Tax Expense		212,648		
75						
76		Federal Taxable Income		$ 607,566		
77		Montana Corporate Income Tax		43,979		
78		Montana Corporate Taxable		$ 651,546		
79						
80		Montana Corporate Income Tax @ 6.75%	6.75%	43,979		
81						
82		Montana Current Tax Expense		43,979		
83						
84		Total Current Income Tax Expense		$ 256,628		
85						
86		***Deferred Income Tax Computation:***	**Rate**			
87		***Accelerated Tax Depreciation/Depletion***				
88		Tax Depreciation/Depletion		$ 1,571,794		
89		Less Book Depreciation/Depletion		1,307,685		
90		Net Deferred Taxable Income		$ 264,109		
91		Federal Income Tax Rate		35%		
92		Federal Deferred Income Tax Expense-Accelerated Tx Depr/Depl		$ 92,438		

	A	B	C	D	E	F
1		**NorthWestern Energy**				
2		**Bear Paw (NFR) Natural Gas Properties**				
3						
4		**Tax Depreciation/Depletion Summary**				
5						
6						
7		Book Basis - EOY	$12,502,075			
8		Tax Basis - EOY	$13,471,792			
9		Deferred Tax - EOY	$ (969,717)			
10		Federal Tax Rate	35%			
11		Deferred Tax Liab (Asset) - EOY	$ (339,401)			
12						
13		Book Basis - BOY	$12,413,399			
14		Tax Basis - BOY	$14,289,909			
15		Deferred Tax - BOY	$ (1,876,510)			
16		Federal Tax Rate	35%			
17		Deferred Tax Liab (Asset) - BOY	$ (656,779)			

	A	B	C	D	E	F	G
1				**NorthWestern Energy**			
2				**Bear Paw (NFR) Natural Gas Properties**			
3							
4				**Capital Structure**			
5							
6							
7							
8							
9				**Percent**	**Rate of**		
10		**Capital Structure**	**Rate**	**Capitalization**	**Return**		
11		Equity	10.00%	46.08%	4.61%		
12		Debt	5.60%	53.92%	3.02%		
13							
14		Total		100.00%	7.63%		

	A	B	C	D	E	F	G	H
1			**NorthWestern Energy**					
2			**Bear Paw (NFR) Natural Gas Properties**					
3								
4			**Income Statement**					
5			**12 Months Actual Ended December 2015**			Normalizing		
6				2015 Actuals		Adjustments		Test Period
7		**OPERATIONS & MAINTENANCE:**						
8			**Production Expenses**					
9								
10		**Production & Gathering-Operation**						
11		750	Supervision & Engineering	14,820.70				14,820.70
12		751	Maps & Records	-				-
13		752	Gas Wells Expenses	258,044.96				258,044.96
14		753	Field Lines Expenses	4,039.85				4,039.85
15		754	Field Compressor Station Expense	1,196,018.78				1,196,018.78
16		755	Field Comp. Station Fuel & Power	(48,522.22)				(48,522.22)
17		756	Field Meas. & Reg. Station Expense	54,691.72				54,691.72
18		757	Dehydration Expense	699.18				699.18
19		758	Gas Well Royalties	267,347.09				267,347.09
20		759	Other Expenses	371,386.48				371,386.48
21		760	Rents	129,262.06				129,262.06
22		**Total Oper. Production & Gathering**		2,247,788.60		-		2,247,788.60
23		**Production & Gathering-Maintenance**						
24		761	Supervision and Engineering	-				-
25		762	Structures and Improvements	-				-
26		763	Producing Gas Wells	4,275.94				4,275.94
27		764	Field Lines	102,750.21	(a)	(55,645.15)		47,105.06
28		765	Field Compressor Station Equipment	173,887.94				173,887.94
29		766	Field Measuring and Regulating Station Equipment	5,166.24				5,166.24
30		767	Purification Equipment	6,000.49				6,000.49
31		768	Drilling and Cleaning Equipment	-				-
32		769	Other Equipment	367.62				367.62
33		**Total Maint. Production & Gathering**		292,448.44		(55,645.15)		236,803.29
34		**Total Production & Gathering Expenses**		2,540,237.04		(55,645.15)		2,484,591.89
35								
36		**Admin. & General - Operation**						
37		920	Administrative & General Salaries	-				-
38		921	Office Supplies & Expenses					
39		925	Injuries & Damages	-				-
40		**Total Operation-Admin. & General**		-		-		-
41		**Total Admin. & General Expenses**		-		-		-
42								
43		**TOTAL OPER. & MAINT. EXPENSES**		2,540,237.04		(55,645.15)		2,484,591.89
44								
45		408.1	Payroll Taxes	46,959.19				46,959.19
46			Vehicle Taxes	1,773.62				1,773.62
47			Total Labor & Vehicle Taxes	48,732.81		-		48,732.81
48								
49								
50		408.1	Property Taxes	149,701.06				149,701.06
51			Production Taxes	70,985.40				70,985.40
52			MPSC/MCC Taxes	15,083.24				15,083.24
53			Other Taxes	-				-
54								
55		457110	Non-operating	30,365.93				30,365.93
56		469610	Miscellaneous Revenues	354,291.98				354,291.98
57		459100	Gathering Revenues	644,387.75				644,387.75
58		492200	Liquid Sales	-				-
59				1,029,045.66		-		1,029,045.66
60								
61								
62			(a) Eliminate write-off of obsolete inventory booked in 2015.					

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	NORTHWESTERN ENERGY - MONTANA GAS PLANT BEAR PAW - 2015 ACCRUAL CALCULATION																			
2						Depr/Depl														
3				Plant Balance		Reserve		OC-D		Accrual		TOTAL				Proposed		TOTAL Proposed		
4				12/31/2014		12/31/2014		12/31/2014		%		2015 Accrual		2015 Depletion		Accrual %		2015 Accrual		
5																				
6																				
7																				
8	G325	Land		367,894.16		1,314.74		366,579.42		0.0000		0				0		0		
9	G325.2	Gas Leaseholds		11,060,103.46		2,778,011.37		8,282,092.09		Depletion		0		1,018,201						
10	G327	Field Compressor Structure		12,325.75		375.96		11,949.79		0.0305		376				0.0223		275		
11	G328	Field Measuring & Regulating Structure		262,707.18		8,012.52		254,694.66		0.0305		8,013				0.0248		6,515		
12	G330	Producing Gas Wells - Construction		1,248,226.30		331,260.94		916,965.36		Depletion		0		112,732						
13	G331	Producing Gas Wells - Equipment		1,257,631.86		326,094.82		931,537.04		Depletion		0		114,523						
14	G332	Field Lines		1,319,857.47		81,792.24		1,238,065.23		0.0305		40,256				0.0306		40,388		
15	G333	Field Compressor Equipment		203,641.32		6,389.79		197,251.53		0.0305		6,211				0.0307		6,252		
16	G334.1	Field Measuring & Regulating Equip		180,859.49		6,807.42		174,052.07		0.0305		5,516				0.0306		5,534		
17	G334.2	Field Dehydration Equipment		15,258.49		553.24		14,705.25		0.0305		465				0.0306		467		
18	G392.2	Transportation - Vehicles		9,322.00		2,279.08		7,042.92		0.0200		186				0.125		1,165		
19	G392.7	Transportation - ATV's		7,358.08		2,123.26		5,234.82		0.1250		920				0.125		920		
20	G394	Tools		14,251.31		1,022.74		13,228.57		0.0500		713				0.05		713		
21																				
22		Total Bear Paw		15,959,436.87		3,546,038.12		12,413,398.75				62,656		1,245,457				62,228		
23																				
24																				
25						Normalized														
26				Depletion		Depletion		Depreciation												
27																				
28		Jan		131,107.65		103,788.05		5,185.68												
29		Feb		116,050.41		103,788.05		5,185.68												
30		Mar		109,464.49		103,788.05		5,185.68												
31		Apr		118,245.71		103,788.05		5,185.68												
32		May		115,533.48		103,788.05		5,185.68												
33		Jun		114,327.75		103,788.05		5,185.68												
34		Jul		109,770.48		103,788.05		5,185.68												
35		Aug		112,890.26		103,788.05		5,185.68												
36		Sep		110,735.32		103,788.05		5,185.68												
37		Oct		107,955.38		103,788.05		5,185.68												
38		Nov		108,704.08		103,788.05		5,185.68												
39		Dec		194,832.72	*	103,788.05		5,185.68												
40																				
41		Total		1,449,617.73		1,245,456.56		62,228.22												
42																				
43																				
44	*	Recorded all 2015 production retroactively for the Black Hills acquisition																		

	A	B	C	D	E	F	G	H	I	J	K	L	M
1			NORTHWESTERN ENERGY - MONTANA GAS OPERATIONS - 2015 BEAR PAW RATE BASE										
2								DEPR/DEPL				DEFERRED INCOME TAXES	
3						PLANT BALANCE		RESERVE		OC-D		NET ACTIVITY	ENDING BALANCE
4													
5	1		DECEMBER	2014		$ 15,959,437		$ 3,546,038		$ 12,413,399		$ (656,779)	$ (656,779)
6													
7	2		JANUARY	2015		$ 15,970,124		$ 3,682,552		$ 12,287,572		$ 26,448	$ (630,330)
8													
9	3		FEBRUARY	2015		$ 15,955,301		$ 3,802,649		$ 12,152,651		$ 26,448	$ (603,882)
10													
11	4		MARCH	2015		$ 15,955,301		$ 3,928,715		$ 12,026,585		$ 26,448	$ (577,434)
12													
13	5		APRIL	2015		$ 15,955,301		$ 4,052,046		$ 11,903,255		$ 26,448	$ (550,986)
14													
15	6		MAY	2015		$ 15,955,301		$ 4,172,659		$ 11,782,642		$ 26,448	$ (524,538)
16													
17	7		JUNE	2015		$ 15,955,301		$ 4,292,062		$ 11,663,239		$ 26,448	$ (498,090)
18													
19	8		JULY	2015		$ 15,955,301		$ 4,406,906		$ 11,548,394		$ 26,448	$ (471,642)
20													
21	9		AUGUST	2015		$ 15,951,824		$ 4,524,839		$ 11,426,985		$ 26,448	$ (445,193)
22													
23	10		SEPTEMBER	2015		$ 15,951,824		$ 4,640,642		$ 11,311,182		$ 26,448	$ (418,745)
24													
25	11		OCTOBER	2015		$ 15,951,824		$ 4,753,661		$ 11,198,163		$ 26,448	$ (392,297)
26													
27	12		NOVEMBER	2015		$ 15,951,824		$ 4,867,421		$ 11,084,403		$ 26,448	$ (365,849)
28													
29	13		DECEMBER	2015		$ 17,573,466		$ 5,071,391		$ 12,502,075		$ 26,448	$ (339,401)
30													
31													
32			13 MONTH AVERAGE			$ 16,080,164		$ 4,287,814		$ 11,792,350			$ (498,090)

	A	B	C	D	E	F
1		**NorthWestern Energy**				
2		**South Bear Paw (Devon) Natural Gas Properties**				
3		**Docket No. D2016.9.68**				
4						
5		**Revenue Requirement Analysis**				
6						
7						
8				**31-Dec-14**		
9		**Description**		Year End		13-Month Ave
10		**Utility Plant in Service**				
11		South Bear Paw		$ 61,687,778		$ 61,684,502
12						
13		Total Plant in Service		$ 61,687,778		$ 61,684,502
14						
15		Less:				
16		Accumulated Depreciation & Depletion		$ 5,260,106		$ 2,638,224
17		Total Net Plant		$ 56,427,672		$ 59,046,278
18						
19		Less: Customer Contributed Capital				
20		Deferred Income Taxes				
21		Accelerated Tax Depreciation/Depletion		$ 1,690,401		$ 1,374,733
22						
23		Total Customer Contributed Capital		$ 1,690,401		$ 1,374,733
24						
25		Total Year End Rate Base		$ 54,737,271		$ 57,671,545
26						
27		**Rate of Return**				7.54%
28						
29		***Authorized Return (Avg. Rate Base * Rate of Return)***				$ 4,348,435
30						
31		***Cost of Service:***				
32		Operation & Maintenance Expenses		$ 10,869,577		
33		Depreciation Expense		22,032		
34		Depletion Expense		5,176,977		
35		Property & Other Taxes		1,789,677		
36		MPSC & MCC Revenue Tax (Order 7370 & 7371)	0.30%	50,431		
37		Misc. Revenues		(489,287)		
38		Non-operating Revenues		(9,699)		
39		Oil and Liquid Sales		(253,718)		
40		Gathering Revenues		(1,655,102)		
41		Deferred Income Taxes		650,323		
42		Current Income Taxes		909,112		
43		***Total Cost of Service***				$ 17,060,323
44						
45		***Less Variable Costs:***				
46		Production Taxes		1,487,113		
47		Royalty Expense		3,111,301		
48		***Total Variable Cost of Service***				4,598,414
49						
50		**Total Fixed Revenue Requirement (Ln 29 + Ln 43 - Ln 48)**				$ 16,810,343
51						
52		**2014 Test Period Normalized Load (Dkt)**				19,686,697
53						
54		**Fixed Cost Unit Rate Year 2014**		(Ln 50 / Ln 52)		$ 0.8539

	A	B	C	D	E	F
55						
56						
57						
58		***Income Tax Computation:***	Rate			
59		Revenues		$ 16,810,343		
60		Operating Expenses		7,758,275		
61		Miscellaneous Revenues		(489,287)		
62		Non-operating Revenues		(9,699)		
63		Oil and Liquid Sales		(253,718)		
64		Gathering Revenues		(1,655,102)		
65		Property & Other Taxes		302,564		
66		MPSC & MCC Revenue Tax		50,431		
67		Tax Depreciation/Depletion		7,057,075		
68		Montana Corporate Income Tax		155,798		
69		Interest Expense (Based on Avg. Rate Base)	3.02%	1,741,681		
70		Federal Taxable Income		$ 2,152,324		
71						
72		Federal Income Tax @ 35%	35.00%	753,314		
73						
74		Federal Current Tax Expense		753,314		
75						
76		Federal Taxable Income		$ 2,152,324		
77		Montana Corporate Income Tax		155,798		
78		Montana Corporate Taxable		$ 2,308,123		
79						
80		Montana Corporate Income Tax @ 6.75%	6.75%	155,798		
81						
82		Montana Current Tax Expense		155,798		
83						
84		Total Current Income Tax Expense		$ 909,112		
85						
86		***Deferred Income Tax Computation:***	Rate			
87		***Accelerated Tax Depreciation/Depletion***				
88		Tax Depreciation/Depletion		$ 7,057,075		
89		Less Book Depreciation/Depletion		5,199,009		
90		Net Deferred Taxable Income		$ 1,858,066		
91		Federal Income Tax Rate		35%		
92		Federal Deferred Income Tax Expense-Accelerated Tx Depr/Depl		$ 650,323		

	A	B	C	D	E	F
1		NorthWestern Energy				
2		South Bear Paw (Devon) Natural Gas Properties				
3						
4		Tax Depreciation/Depletion Summary				
5						
6						
7		Book Basis - EOY	$56,427,672			
8		Tax Basis - EOY	$51,597,956			
9		Deferred Tax - EOY	$ 4,829,716			
10		Federal Tax Rate	35%			
11		Deferred Tax Liab (Asset) - EOY	$ 1,690,401			
12						
13		Book Basis - BOY	$61,702,541			
14		Tax Basis - BOY	$58,676,640			
15		Deferred Tax - BOY	$ 3,025,901			
16		Federal Tax Rate	35%			
17		Deferred Tax Liab (Asset) - BOY	$ 1,059,065			

	A	B	C	D	E	F	G
1				**NorthWestern Energy**			
2				**South Bear Paw (Devon) Natural Gas Properties**			
3							
4				**Capital Structure**			
5							
6							
7							
8							
9				**Percent**	**Rate of**		
10		**Capital Structure**	**Rate**	**Capitalization**	**Return**		
11		Equity	9.80%	46.08%	4.52%		
12		Debt	5.60%	53.92%	3.02%		
13							
14		Total		100.00%	7.54%		

	A	B	C	D	E	F	G	H
1			NorthWestern Energy					
2			South Bear Paw (Devon) Natural Gas Properties					
3								
4			Expenses					
5			12 Months Actual Ended December 2014			Normalizing		
6				2014 Actuals		Adjustments		Test Period
7		OPERATIONS & MAINTENANCE:						
8			Production Expenses					
9								
10		Production & Gathering-Operation						
11		750	Supervision & Engineering	51,305.40				51,305.40
12		751	Maps & Records	-				-
13		752	Gas Wells Expenses	544,083.12	(a) & (b)	562,235.60		1,106,318.72
14		753	Field Lines Expenses	6,728.29				6,728.29
15		754	Field Compressor Station Expense	4,685,756.83	(c)	(158,583.00)		4,527,173.83
16		755	Field Comp. Station Fuel & Power	513,284.22				513,284.22
17		756	Field Meas. & Reg. Station Expense	150,453.45				150,453.45
18		757	Dehydration Expense	6,888.00				6,888.00
19		758	Gas Well Royalties	3,111,301.25				3,111,301.25
20		759	Other Expenses	1,038,934.48				1,038,934.48
21		760	Rents	125,576.54				125,576.54
22		Total Oper. Production & Gathering		10,234,311.58		403,652.60		10,637,964.18
23		Production & Gathering-Maintenance						
24		761	Supervision and Engineering	-				-
25		762	Structures and Improvements	-				-
26		763	Producing Gas Wells	60,132.25				60,132.25
27		764	Field Lines	111,952.24				111,952.24
28		765	Field Compressor Station Equipment	38,630.07				38,630.07
29		766	Field Measuring and Regulating Station Equipment	3,206.50				3,206.50
30		767	Purification Equipment	16,507.94				16,507.94
31		768	Drilling and Cleaning Equipment	-				-
32		769	Other Equipment	1,183.43				1,183.43
33		Total Maint. Production & Gathering		231,612.43		-		231,612.43
34		Total Production & Gathering Expenses		10,465,924.01		403,652.60		10,869,576.61
35								
36		Admin. & General - Operation						
37		920	Administrative & General Salaries	-				-
38		921	Office Supplies & Expenses	-				-
39		Total Operation-Admin. & General		-		-		-
40		Total Admin. & General Expenses		-		-		-
41								
42		TOTAL OPER. & MAINT. EXPENSES		10,465,924.01		403,652.60		10,869,576.61
43								
44		408.1	Payroll Taxes	93,272.29				93,272.29
45			Vehicle Taxes	15,937.75				15,937.75
46			Subtoal Labor Taxes	109,210.04		-		109,210.04
47								
48		408.1	Property Taxes	193,354.37				193,354.37
49			Production Taxes	1,487,112.66				1,487,112.66
50			MPSC/MCC Taxes	-				-
51			Other Taxes	-				-
52								
53		457110	Non-operating Revenues	9,698.73				9,698.73
54		469610	Miscellaneous Revenues	489,286.72				489,286.72
55		459100	Gathering Revenues	1,655,102.39				1,655,102.39
56		492200	Liquid Sales	253,718.48				253,718.48
57			Total Miscellaneous Revenues	2,407,806.32		-		2,407,806.32
58								
59								
60			(a) Road and trail damage paid in 2015 relating to year 2014 for $61,835.					
61								
62			(b) Removal of credit to South Bear Paw expense for overhead of HPC for $500,400.					
63								
64			(c) Eliminate prior period adjustment relating to the effect of accounting and allocation adjustments to the natural gas					
65			tracker reflecting the proper allocation of Bear Paw (NFR) and South Bear Paw (Devon).					
66								

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	NORTHWESTERN ENERGY - MONTANA GAS PLANT SOUTH BEAR PAW - 2014 ACCRUAL CALCULATION													
2														
3				Plant Balance		Depr/Depl Reserve		OC-D		Accrual		TOTAL		
4				12/31/2013		12/31/2013		12/31/2013		%		2014 Accrual		2014 Depletion
5														
6														
7														
8	G325	Land		392,040.00		523.28		391,516.72		0.0000		0		
9	G325.2	Gas Leaseholds		55,935,152.15		0.00		55,935,152.15		Depletion		0		4,791,499
10	G330	Producing Gas Wells - Construction		2,250,000.00		0.00		2,250,000.00		Depletion		0		192,739
11	G331	Producing Gas Wells - Equipment		2,250,000.00		0.00		2,250,000.00		Depletion		0		192,739
12	G390	General Structure		807,960.00		4,129.23		803,830.77		0.0211		17,048		
13	G397.2	Communication		74,729.35		2,688.19		72,041.16		0.0667		4,984		
14														
15		Total South Bear Paw		61,709,881.50		7,340.70		61,702,540.80				22,032		5,176,977
16														
17														
18														
19				Depletion		Depreciation		Total Expense						
20														
21		Jan		446,124.79		1,836.00		447,960.79						
22		Feb		448,627.40		1,836.00		450,463.40						
23		Mar		378,402.51		1,836.00		380,238.51						
24		Apr		472,808.32		1,836.00		474,644.32						
25		May		417,328.25		1,836.00		419,164.25						
26		Jun		410,292.94		1,836.00		412,128.94						
27		Jul		416,213.97		1,836.00		418,049.97						
28		Aug		471,230.91		1,836.00		473,066.91						
29		Sep		452,822.96		1,836.00		454,658.96						
30		Oct		422,750.43		1,836.00		424,586.43						
31		Nov		436,853.58		1,836.00		438,689.58						
32		Dec		403,521.23		1,836.00		405,357.23						
33														
34		Total		5,176,977.29		22,032.00		5,199,009.29						
35														
36														
37	*													

	A	B	C	D	E	F	G	H	I	J	K	L	M
1			NORTHWESTERN ENERGY - MONTANA GAS OPERATIONS - 2014 SOUTH BEAR PAW RATE BASE										
2								DEPR/DEPL				DEFERRED INCOME TAXES	
3						PLANT BALANCE		RESERVE		OC-D		NET ACTIVITY	ENDING BALANCE
4													
5	1		DECEMBER	2013		$ 61,709,882		$ 7,341		$ 61,702,541		$ 1,059,065	$ 1,059,065
6													
7	2		JANUARY	2014		$ 61,724,615		$ 455,562		$ 61,269,052		$ 52,611	$ 1,111,676
8													
9	3		FEBRUARY	2014		$ 61,725,954		$ 905,869		$ 60,820,086		$ 52,611	$ 1,164,288
10													
11	4		MARCH	2014		$ 61,715,691		$ 1,291,990		$ 60,423,701		$ 52,611	$ 1,216,899
12													
13	5		APRIL	2014		$ 61,719,375		$ 1,770,121		$ 59,949,255		$ 52,611	$ 1,269,510
14													
15	6		MAY	2014		$ 61,730,712		$ 2,193,197		$ 59,537,515		$ 52,611	$ 1,322,122
16													
17	7		JUNE	2014		$ 61,740,398		$ 2,609,555		$ 59,130,844		$ 52,611	$ 1,374,733
18													
19	8		JULY	2014		$ 61,740,398		$ 3,031,046		$ 58,709,352		$ 52,611	$ 1,427,344
20													
21	9		AUGUST	2014		$ 61,740,398		$ 3,507,276		$ 58,233,122		$ 52,611	$ 1,479,955
22													
23	10		SEPTEMBER	2014		$ 61,549,042		$ 3,987,731		$ 57,561,311		$ 52,611	$ 1,532,567
24													
25	11		OCTOBER	2014		$ 61,557,143		$ 4,416,925		$ 57,140,218		$ 52,611	$ 1,585,178
26													
27	12		NOVEMBER	2014		$ 61,557,143		$ 4,860,195		$ 56,696,948		$ 52,611	$ 1,637,789
28													
29	13		DECEMBER	2014		$ 61,687,778		$ 5,260,106		$ 56,427,672		$ 52,611	$ 1,690,401
30													
31													
32			13 MONTH AVERAGE			$ 61,684,502		$ 2,638,224		$ 59,046,278			$ 1,374,733

	A	B	C	D	E	F
1		**NorthWestern Energy**				
2		**South Bear Paw (Devon) Natural Gas Properties**				
3		**Docket No. D2016.9.68**				
4						
5		**Revenue Requirement Analysis**				
6						
7						
8				**31-Dec-15**		
9		**Description**		Year End		13-Month Ave
10		**Utility Plant in Service**				
11		South Bear Paw		$ 61,820,359		$ 61,756,259
12						
13		Total Plant in Service		$ 61,820,359		$ 61,756,259
14						
15		Less:				
16		Accumulated Depreciation & Depletion		$ 9,702,348		$ 7,498,904
17		Total Net Plant		$ 52,118,011		$ 54,257,356
18						
19		Less: Customer Contributed Capital				
20		Deferred Income Taxes				
21		Accelerated Tax Depreciation/Depletion		$ 1,723,571		$ 1,706,986
22						
23		Total Customer Contributed Capital		$ 1,723,571		$ 1,706,986
24						
25		Total Year End Rate Base		$ 50,394,440		$ 52,550,370
26						
27		**Rate of Return**				7.54%
28						
29		***Authorized Return (Avg. Rate Base * Rate of Return)***				$ 3,962,298
30						
31		***Cost of Service:***				
32		Operation & Maintenance Expenses		$ 7,902,492		
33		Depreciation Expense		146,319		
34		Depletion Expense		4,290,804		
35		Property & Other Taxes		800,708		
36		MPSC & MCC Revenue Tax (Order 7437 & 7438)	0.29%	44,406		
37		Misc. Revenues		(401,529)		
38		Non-operating Revenues		-		
39		Oil and Liquid Sales		(135,129)		
40		Gathering Revenues		(971,873)		
41		Deferred Income Taxes		35,128		
42		Current Income Taxes		1,501,120		
43		***Total Cost of Service***				$ 13,212,447
44						
45		***Less Variable Costs:***				
46		Production Taxes		505,698		
47		Royalty Expense		1,356,666		
48		***Total Variable Cost of Service***				1,862,364
49						
50		**Total Fixed Revenue Requirement (Ln 29 + Ln 43 - Ln 48)**				$ 15,312,381
51						
52		**2015 Test Period Normalized Load (Dkt)**				19,106,584
53						
54		**Fixed Cost Unit Rate Year 2015**		(Ln 50 / Ln 52)		$ 0.8014

	A	B	C	D	E	F
55						
56						
57						
58		***Income Tax Computation:***	**Rate**			
59		Revenues		$ 15,312,381		
60		Operating Expenses		6,545,826		
61		Miscellaneous Revenues		(401,529)		
62		Non-operating Revenues		-		
63		Oil and Liquid Sales		(135,129)		
64		Gathering Revenues		(971,873)		
65		Property & Other Taxes		295,010		
66		MPSC & MCC Revenue Tax		44,406		
67		Tax Depreciation/Depletion		4,537,489		
68		Montana Corporate Income Tax		257,253		
69		Interest Expense (Based on Avg. Rate Base)	3.02%	1,587,021		
70		Federal Taxable Income		$ 3,553,906		
71						
72		Federal Income Tax @ 35%	35.00%	1,243,867		
73						
74		Federal Current Tax Expense		1,243,867		
75						
76		Federal Taxable Income		$ 3,553,906		
77		Montana Corporate Income Tax		257,253		
78		Montana Corporate Taxable		$ 3,811,159		
79						
80		Montana Corporate Income Tax @ 6.75%	6.75%	257,253		
81						
82		Montana Current Tax Expense		257,253		
83						
84		Total Current Income Tax Expense		$ 1,501,120		
85						
86		***Deferred Income Tax Computation:***	**Rate**			
87		***Accelerated Tax Depreciation/Depletion***				
88		Tax Depreciation/Depletion		$ 4,537,489		
89		Less Book Depreciation/Depletion		4,437,122		
90		Net Deferred Taxable Income		$ 100,366		
91		Federal Income Tax Rate		35%		
92		Federal Deferred Income Tax Expense-Accelerated Tx Depr/Depl		$ 35,128		

	A	B	C	D	E	F
1		NorthWestern Energy				
2		South Bear Paw (Devon) Natural Gas Properties				
3						
4		Tax Depreciation/Depletion Summary				
5						
6						
7		Book Basis - EOY	$52,118,011			
8		Tax Basis - EOY	$47,193,522			
9		Deferred Tax - EOY	$ 4,924,489			
10		Federal Tax Rate	35%			
11		Deferred Tax Liab (Asset) - EOY	$ 1,723,571			
12						
13		Book Basis - BOY	$56,427,672			
14		Tax Basis - BOY	$51,597,956			
15		Deferred Tax - BOY	$ 4,829,716			
16		Federal Tax Rate	35%			
17		Deferred Tax Liab (Asset) - BOY	$ 1,690,401			

	A	B	C	D	E	F	G
1		NorthWestern Energy					
2		South Bear Paw (Devon) Natural Gas Properties					
3							
4		Capital Structure					
5							
6							
7							
8							
9				Percent	Rate of		
10		Capital Structure	Rate	Capitalization	Return		
11		Equity	9.80%	46.08%	4.52%		
12		Debt	5.60%	53.92%	3.02%		
13							
14		Total		100.00%	7.54%		

	A	B	C	D	E	F	G	H
1			NorthWestern Energy					
2			South Bear Paw (Devon) Natural Gas Properties					
3								
4			Expenses					
5			12 Months Actual Ended December 2015			Normalizing		
6				2015 Actuals		Adjustments		Test Period
7		OPERATIONS & MAINTENANCE:						
8			Production Expenses					
9								
10		Production & Gathering-Operation						
11		750	Supervision & Engineering	20,365.52				20,365.52
12		751	Maps & Records	-				-
13		752	Gas Wells Expenses	734,300.41	(a) & (b)	438,564.40		1,172,864.81
14		753	Field Lines Expenses	2,904.53				2,904.53
15		754	Field Compressor Station Expense	3,886,416.19				3,886,416.19
16		755	Field Comp. Station Fuel & Power	91,836.14				91,836.14
17		756	Field Meas. & Reg. Station Expense	87,671.06				87,671.06
18		757	Dehydration Expense	2,514.38				2,514.38
19		758	Gas Well Royalties	1,356,666.40				1,356,666.40
20		759	Other Expenses	994,131.38				994,131.38
21		760	Rents	93,966.76				93,966.76
22		Total Oper. Production & Gathering		7,270,772.77		438,564.40		7,709,337.17
23		Production & Gathering-Maintenance						
24		761	Supervision and Engineering	-				-
25		762	Structures and Improvements	-				-
26		763	Producing Gas Wells	41,103.17	(c)	(17,484.55)		23,618.62
27		764	Field Lines	124,995.66				124,995.66
28		765	Field Compressor Station Equipment	31,300.03				31,300.03
29		766	Field Measuring and Regulating Station Equipment	6,693.00				6,693.00
30		767	Purification Equipment	10,887.21				10,887.21
31		768	Drilling and Cleaning Equipment	-				-
32		769	Other Equipment	(4,339.61)				(4,339.61)
33		Total Maint. Production & Gathering		210,639.46		(17,484.55)		193,154.91
34		Total Production & Gathering Expenses		7,481,412.23		421,079.85		7,902,492.08
35								
36		Admin. & General - Operation						
37		920	Administrative & General Salaries	-				-
38		921	Office Supplies & Expenses					-
39		925	Injuries & Damages	-				-
40		Total Operation-Admin. & General		-		-		-
41		Total Admin. & General Expenses		-		-		-
42								
43		TOTAL OPER. & MAINT. EXPENSES		7,481,412.23		421,079.85		7,902,492.08
44								
45		408.1	Payroll Taxes	91,681.50				91,681.50
46			Vehicle Taxes	9,472.26				9,472.26
47			Subtoal Labor Taxes	101,153.76		-		101,153.76
48								
49		408.1	Property Taxes	193,856.47				193,856.47
50			Production Taxes	505,698.08				505,698.08
51			MPSC/MCC Taxes	67,477.41				67,477.41
52			Other Taxes	-				
53								
54		457110	Non-operating Revenues	-				-
55		469610	Miscellaneous Revenues	401,528.88				401,528.88
56		459100	Gathering Revenues	971,872.59				971,872.59
57		492200	Liquid Sales	135,128.54				135,128.54
58			Total Miscellaneous Revenues	1,508,530.01		-		1,508,530.01
59								
60								
61			(a) Eliminate road and trail damage relating to year 2014 booked in 2015 for (61,835).					
62			(b) Removal of credit to South Bear Paw expense for overhead of HPC for $500,400.					
63			(c) Eliminate capital project write-off					

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	NORTHWESTERN ENERGY - MONTANA GAS PLANT SOUTH BEAR PAW - 2015 ACCRUAL CALCULATION																			
2						Depr/Depl														
3				Plant Balance		Reserve		OC-D		Accrual		TOTAL				Proposed		TOTAL Proposed		
4				12/31/2014		12/31/2014		12/31/2014		%		2015 Accrual		2015 Depletion		Accrual %		2015 Accrual		
5																				
6																				
7	G303.5	Software		111,820.13		20,458.53		91,361.60		0.2000		22,364				0.2000		22,364		
8	G325	Land		389,999.43		836.24		389,163.19		0.0000		0				0.0000		0		
9	G325.2	Gas Leaseholds		52,560,690.77		4,743,694.88		47,816,995.89		Depletion		0		3,952,311						
10	G330	Producing Gas Wells - Construction		2,238,288.73		192,738.80		2,045,549.93		Depletion		0		169,075						
11	G331	Producing Gas Wells - Equipment		2,240,371.76		190,669.61		2,049,702.15		Depletion		0		169,418						
12	G332	Field Lines		640,844.00		23,828.06		617,015.94		0.0305		19,546				0.0306		19,610		
13	G333	Field Compressor Equipment		797,948.00		15,022.66		782,925.34		0.0305		24,337				0.0307		24,497		
14	G334.1	Field Measuring & Regulating Equip		1,387,545.00		34,346.05		1,353,198.95		0.0305		42,320				0.0306		42,459		
15	G334.2	Field Dehydration Equip		410,688.90		8,816.95		401,871.95		0.0305		12,526				0.0306		12,567		
16	G390	General Structure		803,754.57		18,418.71		785,335.86		0.0211		16,959				0.0221		17,763		
17	G392.7	Transportation - ATV's		1.00		0.17		0.83		0.1250		0				0.1250		0		
18	G396	POE		3.00		0.48		2.52		0.1250		0				0.1250		0		
19	G397.2	Communication		105,822.67		11,275.13		94,547.54		0.0667		7,058				0.0667		7,058		
20																				
21		Total South Bear Paw		61,687,777.96		5,260,106.27		56,427,671.69				145,111		4,290,804				146,319		
22																				
23																				
24						Normalized														
25				Depletion		Depletion		Depreciation												
26																				
27		Jan		387,501.58		357,566.98		12,193.22												
28		Feb		368,837.46		357,566.98		12,193.22												
29		Mar		342,955.42		357,566.98		12,193.22												
30		Apr		372,948.90		357,566.98		12,193.22												
31		May		351,043.56		357,566.98		12,193.22												
32		Jun		357,067.00		357,566.98		12,193.22												
33		Jul		354,091.45		357,566.98		12,193.22												
34		Aug		362,776.31		357,566.98		12,193.22												
35		Sep		356,356.35		357,566.98		12,193.22												
36		Oct		354,718.88		357,566.98		12,193.22												
37		Nov		351,309.21		357,566.98		12,193.22												
38		Dec		351,118.89	*	357,566.98		12,193.22												
39																				
40		Total		4,310,725.01		4,290,803.81		146,318.66												
41																				
42	*	Recorded all 2015 production retroactively for the Wilbanks acquisition																		

	A	B	C	D	E	F	G	H	I	J	K	L	M
1			NORTHWESTERN ENERGY - MONTANA GAS OPERATIONS - 2015 SOUTH BEAR PAW RATE BASE										
2								DEPR/DEPL				DEFERRED INCOME TAXES	
3						PLANT BALANCE		RESERVE		OC-D		NET ACTIVITY	ENDING BALANCE
4													
5	1		DECEMBER	2014		$ 61,687,778		$ 5,260,106		$ 56,427,672			$ 1,690,401
6													
7	2		JANUARY	2015		$ 61,704,620		$ 5,658,691		$ 56,045,930		$ 2,764	$ 1,693,165
8													
9	3		FEBRUARY	2015		$ 61,740,174		$ 6,037,059		$ 55,703,114		$ 2,764	$ 1,695,929
10													
11	4		MARCH	2015		$ 61,760,210		$ 6,380,547		$ 55,379,664		$ 2,764	$ 1,698,693
12													
13	5		APRIL	2015		$ 61,760,210		$ 6,765,413		$ 54,994,797		$ 2,764	$ 1,701,457
14													
15	6		MAY	2015		$ 61,760,210		$ 7,129,832		$ 54,630,379		$ 2,764	$ 1,704,222
16													
17	7		JUNE	2015		$ 61,755,700		$ 7,498,603		$ 54,257,096		$ 2,764	$ 1,706,986
18													
19	8		JULY	2015		$ 61,755,700		$ 7,870,256		$ 53,885,443		$ 2,764	$ 1,709,750
20													
21	9		AUGUST	2015		$ 61,755,700		$ 8,245,123		$ 53,510,577		$ 2,764	$ 1,712,514
22													
23	10		SEPTEMBER	2015		$ 61,751,830		$ 8,613,553		$ 53,138,277		$ 2,764	$ 1,715,278
24													
25	11		OCTOBER	2015		$ 61,789,396		$ 8,980,407		$ 52,808,989		$ 2,764	$ 1,718,043
26													
27	12		NOVEMBER	2015		$ 61,789,486		$ 9,343,808		$ 52,445,678		$ 2,764	$ 1,720,807
28													
29	13		DECEMBER	2015		$ 61,820,359		$ 9,702,348		$ 52,118,011		$ 2,764	$ 1,723,571
30													
31													
32			13 MONTH AVERAGE			$ 61,756,259		$ 7,498,904		$ 54,257,356			$ 1,706,986

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**NorthWestern Energy**															
2	**Natural Gas Production**															
3	**Bear Paw - Revenue Comparison**															
4												(Col. J - Col. F)				(Col. L + Col. N)
5			***Amount Billed Customers at Bridge Rates***					***Updated Revenue Requirements***						First		
6				Billed		Fixed				Fixed		(Over)/Under	(f)	Interim Bridge		(Over)/Under
7			Rate/Dkt	Dkt Volumes		Revenues		Rate/Dkt		Revenues		Collection		Adjustment		Net Adjustment
8	Nov-12	(a)	$ 0.1817	1,663,604		$ 302,274	(c)	$ 0.2522		$ 419,484		$ 117,211				$ 117,211
9	Dec-12		$ 0.1817	2,391,177		$ 434,477		$ 0.2522		$ 602,945		$ 168,468				$ 168,468
10	Jan-13		$ 0.1817	3,246,645		$ 589,915		$ 0.2522		$ 818,655		$ 228,739				$ 228,739
11	Feb-13		$ 0.1817	2,823,598		$ 513,048		$ 0.2522		$ 711,982		$ 198,934				$ 198,934
12	Mar-13		$ 0.1817	2,407,413		$ 437,427		$ 0.2522		$ 607,039		$ 169,612				$ 169,612
13	Apr-13		$ 0.1817	1,832,137		$ 332,899		$ 0.2522		$ 461,981		$ 129,082				$ 129,082
14	May-13		$ 0.1817	1,369,308		$ 248,803		$ 0.2522		$ 345,277		$ 96,473				$ 96,473
15	Jun-13		$ 0.1817	749,596		$ 136,202		$ 0.2522		$ 189,014		$ 52,812				$ 52,812
16	Jul-13		$ 0.1817	524,659		$ 95,331		$ 0.2522		$ 132,295		$ 36,964				$ 36,964
17	Aug-13		$ 0.1817	393,136		$ 71,433		$ 0.2522		$ 99,131		$ 27,698				$ 27,698
18	Sep-13		$ 0.1817	421,139		$ 76,521		$ 0.2522		$ 106,192		$ 29,671				$ 29,671
19	Oct-13		$ 0.1817	1,024,701		$ 186,188		$ 0.2522		$ 258,383		$ 72,194				$ 72,194
20	Nov-13		$ 0.1817	1,761,550		$ 320,074		$ 0.2522		$ 444,182		$ 124,108				$ 124,108
21	Dec-13		$ 0.1817	2,941,440		$ 534,460		$ 0.2522		$ 741,696		$ 207,236				$ 207,236
22	Jan-14		$ 0.1817	3,204,866		$ 582,324	(d)	$ 0.2232		$ 715,367		$ 133,043				$ 133,043
23	Feb-14		$ 0.1817	3,109,432		$ 564,984		$ 0.2232		$ 694,065		$ 129,081				$ 129,081
24	Mar-14		$ 0.1817	3,001,010		$ 545,284		$ 0.2232		$ 669,864		$ 124,580				$ 124,580
25	Apr-14		$ 0.1817	1,988,951		$ 361,392		$ 0.2232		$ 443,959		$ 82,567				$ 82,567
26	May-14		$ 0.1817	1,339,562		$ 243,398		$ 0.2232		$ 299,007		$ 55,609				$ 55,609
27	Jun-14		$ 0.1817	712,942		$ 129,542		$ 0.2232		$ 159,138		$ 29,596				$ 29,596
28	Jul-14		$ 0.1817	510,977		$ 92,844		$ 0.2232		$ 114,056		$ 21,212				$ 21,212
29	Aug-14		$ 0.1817	411,818		$ 74,827		$ 0.2232		$ 91,923		$ 17,096				$ 17,096
30	Sep-14		$ 0.1817	545,069		$ 99,039		$ 0.2232		$ 121,666		$ 22,627				$ 22,627
31	Oct-14		$ 0.1817	729,125		$ 132,482		$ 0.2232		$ 162,750		$ 30,268				$ 30,268
32	Nov-14		$ 0.1817	1,566,385		$ 284,612		$ 0.2232		$ 349,637		$ 65,025				$ 65,025
33	Dec-14		$ 0.1817	2,853,262		$ 518,438		$ 0.2232		$ 636,885		$ 118,447				$ 118,447
34	Jan-15		$ 0.1817	3,378,869		$ 613,940	(e)	$ 0.2090		$ 706,086		$ 92,145				$ 92,145
35	Feb-15		$ 0.1817	2,493,331		$ 453,038		$ 0.2090		$ 521,034		$ 67,996				$ 67,996
36	Mar-15		$ 0.1817	2,353,885		$ 427,701		$ 0.2090		$ 491,894		$ 64,193				$ 64,193
37	Apr-15		$ 0.1817	1,573,781		$ 285,956		$ 0.2090		$ 328,875		$ 42,919				$ 42,919
38	May-15		$ 0.1817	1,155,323		$ 209,922		$ 0.2090		$ 241,429		$ 31,507				$ 31,507
39	Jun-15		$ 0.1817	702,699		$ 127,680		$ 0.2090		$ 146,844		$ 19,163				$ 19,163
40	Jul-15		$ 0.1817	422,151		$ 76,705		$ 0.2090		$ 88,217		$ 11,512				$ 11,512
41	Aug-15		$ 0.1817	419,622		$ 76,245		$ 0.2090		$ 87,689		$ 11,444				$ 11,444
42	Sep-15		$ 0.1817	496,746		$ 90,259		$ 0.2090		$ 103,806		$ 13,547				$ 13,547
43	Oct-15		$ 0.1817	691,633		$ 125,670		$ 0.2090		$ 144,531		$ 18,862				$ 18,862
44	Nov-15	(b)	$ 0.1700	1,439,019		$ 244,609		$ 0.2090		$ 300,713		$ 56,104		$ (169,675)		$ (113,571)
45	Dec-15		$ 0.1700	2,843,629		$ 483,370		$ 0.2090		$ 594,236		$ 110,866		$ (335,292)		$ (224,426)
46	Jan-16		$ 0.1700	3,445,002		$ 585,594		$ 0.2090		$ 719,906		$ 134,312		$ (406,200)		$ (271,888)
47	Feb-16		$ 0.1700	2,665,099		$ 453,023		$ 0.2090		$ 556,929		$ 103,906		$ (314,242)		$ (210,336)
48	Mar-16		$ 0.1700	2,073,810		$ 352,514		$ 0.2090		$ 433,366		$ 80,853		$ (244,438)		$ (163,585)
49	Apr-16		$ 0.1700	1,747,097		$ 296,978		$ 0.2090		$ 365,093		$ 68,115		$ (205,926)		$ (137,811)
50	May-16		$ 0.1700	1,076,906		$ 183,056		$ 0.2090		$ 225,042		$ 41,986		$ (126,929)		$ (84,943)
51	Jun-16		$ 0.1700	781,460		$ 132,835		$ 0.2090		$ 163,303		$ 30,467		$ (92,106)		$ (61,639)
52	Jul-16	(g)	$ 0.1642	481,551		$ 79,071		$ 0.2090		$ 100,630		$ 21,560				$ 21,560
53																
54	Total Billed Customers					$ 13,206,384				$ 16,716,195		$ 3,509,811		$ (1,894,808)		$ 1,615,003
55																
56																
57	*(a) Initial Interim Fixed rate used in the bridge concept.*															
58	*(b) Updated Interim Fixed rate per Order No. 7282d, in Docket No. D2013.5.34.*															
59	*(c) Fixed rate per updated revenue requirement Exhibit (PJD-1) Year 2013.*															
60	*(d) Fixed rate per updated revenue requirement Exhibit (PJD-2) Year 2014.*															
61	*(e) Fixed rate per updated revenue requirement Exhibit (PJD-3) Year 2015.*															

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
62	*(f) As part of the November 2015 Natural Gas Monthly supply tracker Docket No. D2015.7.53, NWE re-calculated the bridge rates for the tracker periods 2012-13 and 2013-14 for Bear Paw and Devon per Commission Order No. 7282d ¶¶ 42 and 43 in Docket Nos. D2013.5.34 and D2014.5.47 and as clarified through discussion with Commission Staff. The updated bridge rates are based on 2013 and 2014 actual revenue requirements as shown in Appendices G, H and I in the November 2015 tracker filing. These updated rates were then used to compute the resulting (over)/under collections for these same tracker periods. The Bear Paw recalculation results in an under-collection of $2,094,924 including interest as shown on line 74 of Appendix J. The Devon recalculation results in an (over)-collection of ($1,847,751) including interest as shown on line 74 of Appendix K. These Bear Paw and Devon (over)/under-collection amounts were refunded and recovered in the natural gas supply tracker through June 2016 per ¶ 43 of Order No. 7282d.*															
63																
72	*(g) As part of the Annual Natural Gas Supply Tracker filed in May 2016, the interim bridge rates were updated per Order 7421b ¶ 19 , Docket No. D2014.7.59 Per ¶ 8 of the Stipulation part 4) since final rates had not been approved for NFR and Devon by the time NorthWestern filed the next natural gas tracker, this bridge rate was updated based on 2016 fixed cost revenue requirement as estimated in the purchase analysis.*															
73																
74																
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76																
77																

NorthWestern Energy
Natural Gas Production
Devon - Revenue Comparison

		Amount Billed Customers at Bridge Rates				Updated Revenue Requirements		(Col. J - Col. F)				(Col. L + Col. N & P)
		Rate/Dkt	Billed Dkt Volumes	Fixed Revenues		Rate/Dkt	Fixed Revenues	(Over)/Under Collection	(e)	First Interim Bridge Adjustment	(f)	Second Interim Bridge Adjustment	(Over)/Under Net Adjustment
Dec-13	(a)	$ 0.9308	2,941,440	$ 2,737,969	(c)	$ 0.8539	$ 2,511,677	$ (226,292)					$ (226,292)
Jan-14		$ 0.9308	3,204,866	$ 2,983,089		$ 0.8539	$ 2,736,614	$ (246,475)					$ (246,475)
Feb-14		$ 0.9308	3,109,432	$ 2,894,259		$ 0.8539	$ 2,655,124	$ (239,135)					$ (239,135)
Mar-14		$ 0.9308	3,001,010	$ 2,793,340		$ 0.8539	$ 2,562,543	$ (230,797)					$ (230,797)
Apr-14		$ 0.9308	1,988,951	$ 1,851,315		$ 0.8539	$ 1,698,352	$ (152,963)					$ (152,963)
May-14		$ 0.9308	1,339,562	$ 1,246,865		$ 0.8539	$ 1,143,844	$ (103,021)					$ (103,021)
Jun-14		$ 0.9308	712,942	$ 663,607		$ 0.8539	$ 608,777	$ (54,830)					$ (54,830)
Jul-14		$ 0.9308	510,977	$ 475,617		$ 0.8539	$ 436,320	$ (39,297)					$ (39,297)
Aug-14		$ 0.9308	411,818	$ 383,320		$ 0.8539	$ 351,649	$ (31,671)					$ (31,671)
Sep-14		$ 0.9308	545,069	$ 507,351		$ 0.8539	$ 465,431	$ (41,919)					$ (41,919)
Oct-14		$ 0.9308	729,125	$ 678,669		$ 0.8539	$ 622,595	$ (56,074)					$ (56,074)
Nov-14		$ 0.9308	1,566,385	$ 1,457,991		$ 0.8539	$ 1,337,526	$ (120,465)					$ (120,465)
Dec-14		$ 0.9308	2,853,262	$ 2,655,817		$ 0.8539	$ 2,436,382	$ (219,434)					$ (219,434)
Jan-15		$ 0.9308	3,378,869	$ 3,145,051	(d)	$ 0.8014	$ 2,707,890	$ (437,161)					$ (437,161)
Feb-15		$ 0.9308	2,493,331	$ 2,320,792		$ 0.8014	$ 1,998,203	$ (322,589)					$ (322,589)
Mar-15		$ 0.9308	2,353,885	$ 2,190,996		$ 0.8014	$ 1,886,448	$ (304,548)					$ (304,548)
Apr-15		$ 0.9308	1,573,781	$ 1,464,876		$ 0.8014	$ 1,261,258	$ (203,617)					$ (203,617)
May-15		$ 0.9308	1,155,323	$ 1,075,375		$ 0.8014	$ 925,898	$ (149,477)					$ (149,477)
Jun-15		$ 0.9308	702,699	$ 654,073		$ 0.8014	$ 563,157	$ (90,916)					$ (90,916)
Jul-15		$ 0.9308	422,151	$ 392,938		$ 0.8014	$ 338,320	$ (54,618)					$ (54,618)
Aug-15		$ 0.9308	419,622	$ 390,584		$ 0.8014	$ 336,293	$ (54,291)					$ (54,291)
Sep-15		$ 0.9308	496,746	$ 462,372		$ 0.8014	$ 398,102	$ (64,270)					$ (64,270)
Oct-15		$ 0.9308	691,633	$ 643,772		$ 0.8014	$ 554,288	$ (89,484)					$ (89,484)
Nov-15	(b)	$ 0.7823	1,439,019	$ 1,125,784		$ 0.8014	$ 1,153,257	$ 27,473		$ 149,658			$ 177,131
Dec-15		$ 0.7823	2,843,629	$ 2,224,649		$ 0.8014	$ 2,278,939	$ 54,289		$ 295,737			$ 350,027
Jan-16		$ 0.7823	3,445,002	$ 2,695,120		$ 0.8014	$ 2,760,890	$ 65,770		$ 358,280			$ 424,051
Feb-16		$ 0.7823	2,665,099	$ 2,084,980		$ 0.8014	$ 2,135,861	$ 50,881		$ 277,170			$ 328,051
Mar-16		$ 0.7823	2,073,810	$ 1,622,399		$ 0.8014	$ 1,661,991	$ 39,592		$ 215,601		$ 442,579	$ 697,773
Apr-16		$ 0.7823	1,747,097	$ 1,366,802		$ 0.8014	$ 1,400,157	$ 33,355		$ 181,632		$ 372,848	$ 587,836
May-16		$ 0.7823	1,076,906	$ 842,494		$ 0.8014	$ 863,053	$ 20,560		$ 111,955		$ 229,817	$ 362,332
Jun-16		$ 0.7823	781,460	$ 611,358		$ 0.8014	$ 626,277	$ 14,919		$ 81,240		$ 166,767	$ 262,927
Jul-16	(g)	$ 0.7777	481,551	$ 374,502		$ 0.8014	$ 385,924	$ 11,422					$ 11,422
				$ 47,018,125			$ 43,803,039	$ (3,215,086)		$ 1,671,275		$ 1,212,012	$ (331,799)

(a) Initial Interim Fixed rate used in the bridge concept.
(b) Updated Interim Fixed rate per Order No. 7282d, in Docket No. D2013.5.34.
(c) Fixed rate per updated revenue requirement Exhibit__(PJD-4) Year 2014.
(d) Fixed rate per updated revenue requirement Exhibit__(PJD-5) Year 2015.

(e) As part of the November 2015 Natural Gas Monthly supply tracker Docket No. D2015.7.53, NWE re-calculated the bridge rates for the tracker periods 2012-13 and 2013-14 for Bear Paw and Devon per Commission Order No. 7282d ¶¶ 42 and 43 in Docket Nos. D2013.5.34 and D2014.5.47 and as clarified through discussion with Commission Staff. The updated bridge rates are based on 2013 and 2014 actual revenue requirements as shown in Appendices G, H and I in the November 2015 tracker filing. These updated rates were then used to compute the resulting (over)/under collections for these same tracker periods. The Bear Paw recalculation results in an under-collection of $2,094,924 including interest as shown on line 74 of Appendix J. The Devon recalculation results in an (over)-collection of ($1,847,751) including interest as shown on line 74 of Appendix K. These Bear Paw and Devon (over)/under-collection amounts were refunded and recovered in the natural gas supply tracker through June 2016 per ¶ 43 of Order No. 7282d.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
58	*(f) Docket No. D2014.7.59, Order No. 7421b - In ¶ 8 of the Stipulation, NorthWestern and MCC reached a fair and equitable resolution of the contested issues in this Docket, a resolution that would establish just and reasonable rates. The resolution included 1) Approval of NorthWestern's application, other than changes described below; 2) NorthWestern agreed to credit customers $1,500,000 associated with estimated over-collections of fixed costs through the NFR and Devon interim bridge rates, subject to final true-up at time of rate base approval. The give back to customers started on March 1, 2016 at rate of ($0.2135/Dkt.) This adjustment is included in the Devon over/under computation, but reflects a $1.5M credit to customers for both Devon and NFR.*																		
67																			
68	*(g) As part of the Annual Natural Gas Supply Tracker filed in May 2016, the interim bridge rates were updated per*																		
69	*Order 7421b ¶ 19 , Docket No. D2014.7.59 Per ¶ 8 of the Stipulation part 4) since final rates had not been*																		
70	*approved for NFR and Devon by the time NorthWestern filed the next natural gas tracker, this bridge rate was*																		
71	*updated based on 2016 fixed cost revenue requirement as estimated in the purchase analysis.*																		
72																			
73																			

	A	B	C	D	E	F
1	**NorthWestern Energy**					
2	**Battle Creek Natural Gas Properties**					
3	**Docket No. D2016.9.68**					
4						
5	**Forecasted - Revenue Requirement**					
6			2016	2017	2018	2019
7	**Utility Plant in Service**					
8	Plant in Service -Bear Paw		$ 12,449,722	$ 12,484,560	$ 12,521,941	$ 12,552,842
9	Common Plant		732,080	814,165	896,249	978,334
10	Total Plant		$ 13,181,802	$ 13,298,725	$ 13,418,191	$ 13,531,176
11						
12	Less:					
13	Accumulated Depreciation & Depletion		$ 3,812,881	$ 4,271,342	$ 4,692,408	$ 5,082,227
14	Accumulated Depreciation - Common Plant		288,322	320,650	352,978	385,306
15	Total Accumulated Depreciation and Depletion		$ 4,101,203	$ 4,591,992	$ 5,045,386	$ 5,467,533
16						
17	Net Plant		$ 9,080,599	$ 8,706,733	$ 8,372,804	$ 8,063,643
18						
19	Less: Customer Contributed Capital					
20	Deferred Income Taxes					
21	Accelerated Tax Depreciation		$ 286,914	$ 264,263	$ 241,219	$ 217,806
22						
23	Plus: Working Capital					
24	Gross Cash Requirements		$ (286,176)	$ (288,789)	$ (292,641)	$ (296,847)
25						
26	Average Rate Base		$ 8,507,509	$ 8,153,682	$ 7,838,945	$ 7,548,989
27						
28	**Rate of Return**		7.33%	7.33%	7.33%	7.33%
29						
30	***Authorized Return (Avg. Rate Base * Rate of Return)***		$ 623,600	$ 597,665	$ 574,595	$ 553,341
31						
32	***Cost of Service:***					
33	Operation & Maintenance Expenses		$ 680,389	$ 684,067	$ 688,856	$ 694,765
34	Administrative & General		521,192	534,222	547,578	561,267
35	Depreciation Expense		84,888	85,418	85,948	86,478
36	Depreciation Common Expense		46,532	53,209	60,845	69,576
37	Depletion Expense		445,664	403,026	369,814	339,471
38	Amortization MPSC & MCC		(232)	(232)	(232)	0
39	Property & Other Taxes		113,440	110,129	107,206	104,670
40	MPSC & MCC Revenue Tax	0.49%	12,144	11,959	11,866	11,811
41	Misc. Revenues		(108,000)	(108,000)	(108,000)	(108,000)
42	Non-operating Revenues		(30,731)	(28,138)	(25,737)	(23,529)
43	Deferred Income Taxes		(22,527)	(22,777)	(23,311)	(23,515)
44	Current Income Taxes		$ 272,762	$ 267,111	$ 266,739	$ 267,011
45	***Total Cost of Service***		$ 2,015,521	$ 1,989,994	$ 1,981,570	$ 1,980,005
46						
47	***Less Variable Costs:***					
48	Production Taxes		$ 56,197	$ 51,455	$ 47,065	$ 43,026
49	Royalty Expense		104,469	95,654	87,492	79,984
50	***Total Variable Cost of Service***		$ 160,666	$ 147,109	$ 134,557	$ 123,010
51						
52	**Total Fixed Revenue Requirement (Ln 30 + Ln 45 - Ln 50)**		$ 2,478,456	$ 2,440,549	$ 2,421,608	$ 2,410,336
53						
54	**Normalized Load (Dkt)**		19,261,583	19,417,978	19,575,783	19,735,012
55	**Fixed Cost Unit Rate Per Year**		$ 0.1287	$ 0.1257	$ 0.1237	$ 0.1221

	A	B	C	D	E	F
1	**NorthWestern Energy**					
2	**Battle Creek Natural Gas Properties**					
3	**Docket No. D2016.9.68**					
4						
5	**Forecasted - Revenue Requirement**					
6			2016	2017	2018	2019
56						
57						
58						
59	***Income Tax Computation:***	Rate				
60	Revenues		$ 2,478,456	$ 2,440,549	$ 2,421,608	$ 2,410,336
61	Operating Expenses		575,919.92	588,412.71	601,363.43	614,780.82
62	Administrative & General		521,192	534,222	547,578	561,267
63	Amortization MPSC & MCC		(232)	(232)	(232)	-
64	Miscellaneous Revenues		(108,000)	(108,000)	(108,000)	(108,000)
65	Non-operating Revenues		(30,731)	(28,138)	(25,737)	(23,529)
66	Property & Other Taxes		57,243	58,674	60,141	61,644
67	MPSC & MCC Revenue Tax		12,144	11,959	11,866	11,811
68	Tax Depreciation/Depletion		466,190	423,367	389,159	358,764
69	Tax Depreciation Common		80,384	79,097	73,064	67,719
70	Montana Corporate Income Tax		46,744	45,776	45,712	45,759
71	Interest Expense (Based on Avg. Rate Base)	2.49%	211,837	203,027	195,190	187,970
72	Federal Taxable Income		$ 645,764	$ 632,385	$ 631,505	$ 632,150
73						
74	Federal Income Tax @ 35%	35.00%	226,017	221,335	221,027	221,253
75						
76	Federal Current Tax Expense		226,017	221,335	221,027	221,253
77						
78	Federal Taxable Income		$ 645,764	$ 632,385	$ 631,505	$ 632,150
79	Montana Corporate Income Tax		46,744	45,776	45,712	45,759
80	Montana Corporate Taxable		$ 692,508	$ 678,161	$ 677,217	$ 677,909
81						
82	Montana Corporate Income Tax @ 6.75%	6.75%	46,744	45,776	45,712	45,759
83						
84	Montana Current Tax Expense		46,744	45,776	45,712	45,759
85						
86	Total Current Income Tax Expense		$ 272,762	$ 267,111	$ 266,739	$ 267,011
87						
88	***Deferred Income Tax Computation:***	Rate				
89	***Accelerated Tax Depreciation***					
90	Tax Depreciation		$ 466,190	$ 423,367	$ 389,159	$ 358,764
91	Less Book Depreciation/Depletion		530,552	488,444	455,762	425,949
92	Net Deferred Taxable Income		$ (64,362)	$ (65,076)	$ (66,603)	$ (67,185)
93	Federal Income Tax Rate		35%	35%	35%	35%
94	Federal Deferred Income Tax Expense-Accelerated Tx Deprec		$ (22,527)	$ (22,777)	$ (23,311)	$ (23,515)

	A	B	C	D	E	F	G	H
1	Battle Creek							
2	Forecasted Depreciation							
3	2016-2019							
4				50%	50%	40%	30%	
5	Tax Class	Additions		2016	2017	2018	2019	Total
6								
7	*DEPLETION G325.2, G330, G331*	-		445,664	403,026	369,814	339,471	1,557,974
8								
9	*MACRS 15 G332, G333, G334.1, G334.2, G368*							
10	2016	9,497		4,986	451	406	366	6,208
11	2017	9,497			4,986	451	406	5,843
12	2018	9,497				4,084	541	4,625
13	2019	9,497					3,181	3,181
14								
15	*MACRS 5 G392.3, G392.7*							-
16	2016	1,335		801	214	128	77	1,219
17	2017	1,335			801	214	128	1,142
18	2018	1,335				694	256	950
19	2019	1,335					587	587
20								
21	2015 AND EARLIER VINTAGES FROM PTAX (Excl Depletion Expense)	-		14,740	13,891	13,369	13,751	55,751
22	TOTAL	43,324		466,190	423,367	389,159	358,764	1,637,481

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1															
2	Roll Forward Schedule														
3	MTU - MTU-Northwestern Energy														
4															
5	2016 Gas Rate Case														
6	Federal														
7							Rpt # 30		2016		7/28/2016 13:53				
8															
9															
10								Grouped By:		Location Rollup					
11	Tax Class Rollup					Balance	Additions		Dispositions			Transfers		Balance	Memo
12						Begin of Period								End of Period	
13															
14	Battle Creek														
15															
16	Total Cost: Book					$12,432,195.16	$0.00		$0.00			$0.00		$12,432,195.16	$0.00
17	Book Tax Differences														
18	AFUDC Debt					($42,935.04)	$0.00		$0.00			$0.00		($42,935.04)	$0.00
19	AFUDC Equity					($63,411.84)	$0.00		$0.00			$0.00		($63,411.84)	$0.00
20	Bonus Depr Reduction					($555,845.31)	$0.00		$0.00			$0.00		($555,845.31)	$0.00
21	Capitalized Interest					$79,463.70	$0.00		$0.00			$0.00		$79,463.70	$0.00
22	Manual Tax Repair Expense					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
23	Section 263(a)					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
24	Tax Repair Expense					($1,838.10)	$0.00		$0.00			$0.00		($1,838.10)	$0.00
25	Taxable CIAC					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
26															
27	Total Book Tax Differences					($584,566.59)	$0.00		$0.00			$0.00		($584,566.59)	$0.00
28	Ordinary Retirements					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
29															
30	Memo					($0.91)	$0.00		$0.00			$0.00		($0.91)	$0.00
31	Tax Balance					$11,847,627.66	$0.00		$0.00			$0.00		$11,847,627.66	$0.00
32															
33	Tax Reserve					$3,869,213.29	$14,740.11		$0.00			$0.00		$3,883,953.40	$0.00
34	Net Value:					$7,978,414.37	($14,740.11)		$0.00			$0.00		$7,963,674.26	$0.00
35	Roll Forward Schedule														
36	MTU - MTU-Northwestern Energy														
37															
38	2016 Gas Rate Case														
39	Federal														
40							Rpt # 30		2017		7/28/2016 13:53				
41															
42															
43								Grouped By:		Location Rollup					
44	Tax Class Rollup					Balance	Additions		Dispositions			Transfers		Balance	Memo
45						Begin of Period								End of Period	
46															
47	Battle Creek														
48															
49	Total Cost: Book					$12,432,195.16	$0.00		$0.00			$0.00		$12,432,195.16	$0.00
50	Book Tax Differences														
51	AFUDC Debt					($42,935.04)	$0.00		$0.00			$0.00		($42,935.04)	$0.00
52	AFUDC Equity					($63,411.84)	$0.00		$0.00			$0.00		($63,411.84)	$0.00
53	Bonus Depr Reduction					($555,845.31)	$0.00		$0.00			$0.00		($555,845.31)	$0.00
54	Capitalized Interest					$79,463.70	$0.00		$0.00			$0.00		$79,463.70	$0.00
55	Manual Tax Repair Expense					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
56	Section 263(a)					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
57	Tax Repair Expense					($1,838.10)	$0.00		$0.00			$0.00		($1,838.10)	$0.00
58	Taxable CIAC					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
59															
60	Total Book Tax Differences					($584,566.59)	$0.00		$0.00			$0.00		($584,566.59)	$0.00
61	Ordinary Retirements					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
62															
63	Memo					($0.91)	$0.00		$0.00			$0.00		($0.91)	$0.00
64	Tax Balance					$11,847,627.66	$0.00		$0.00			$0.00		$11,847,627.66	$0.00
65															
66	Tax Reserve					$3,883,953.40	$13,890.85		$0.00			$0.00		$3,897,844.25	$0.00
67	Net Value:					$7,963,674.26	($13,890.85)		$0.00			$0.00		$7,949,783.41	$0.00
68	Roll Forward Schedule														
69	MTU - MTU-Northwestern Energy														
70															
71	2016 Gas Rate Case														
72	Federal														
73							Rpt # 30		2018		7/28/2016 13:53				

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
74															
75															
76								Grouped By:		Location Rollup					
77	Tax Class Rollup					Balance	Additions		Dispositions			Transfers		Balance	Memo
78						Begin of Period								End of Period	
79															
80	Battle Creek														
81															
82	Total Cost: Book					$12,432,195.16	$0.00		$0.00			$0.00		$12,432,195.16	$0.00
83	Book Tax Differences														
84	AFUDC Debt					($42,935.04)	$0.00		$0.00			$0.00		($42,935.04)	$0.00
85	AFUDC Equity					($63,411.84)	$0.00		$0.00			$0.00		($63,411.84)	$0.00
86	Bonus Depr Reduction					($555,845.31)	$0.00		$0.00			$0.00		($555,845.31)	$0.00
87	Capitalized Interest					$79,463.70	$0.00		$0.00			$0.00		$79,463.70	$0.00
88	Manual Tax Repair Expense					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
89	Section 263(a)					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
90	Tax Repair Expense					($1,838.10)	$0.00		$0.00			$0.00		($1,838.10)	$0.00
91	Taxable CIAC					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
92															
93	Total Book Tax Differences					($584,566.59)	$0.00		$0.00			$0.00		($584,566.59)	$0.00
94	Ordinary Retirements					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
95															
96	Memo					($0.91)	$0.00		$0.00			$0.00		($0.91)	$0.00
97	Tax Balance					$11,847,627.66	$0.00		$0.00			$0.00		$11,847,627.66	$0.00
98															
99	Tax Reserve					$3,897,844.25	$13,368.70		$0.00			$0.00		$3,911,212.95	$0.00
100	Net Value:					$7,949,783.41	($13,368.70)		$0.00			$0.00		$7,936,414.71	$0.00
101	Roll Forward Schedule														
102	MTU - MTU-Northwestern Energy														
103															
104	2016 Gas Rate Case														
105	Federal														
106							Rpt # 30		2019		7/28/2016 13:53				
107															
108															
109								Grouped By:		Location Rollup					
110	Tax Class Rollup					Balance	Additions		Dispositions			Transfers		Balance	Memo
111						Begin of Period								End of Period	
112															
113	Battle Creek														
114															
115	Total Cost: Book					$12,432,195.16	$0.00		$0.00			$0.00		$12,432,195.16	$0.00
116	Book Tax Differences														
117	AFUDC Debt					($42,935.04)	$0.00		$0.00			$0.00		($42,935.04)	$0.00
118	AFUDC Equity					($63,411.84)	$0.00		$0.00			$0.00		($63,411.84)	$0.00
119	Bonus Depr Reduction					($555,845.31)	$0.00		$0.00			$0.00		($555,845.31)	$0.00
120	Capitalized Interest					$79,463.70	$0.00		$0.00			$0.00		$79,463.70	$0.00
121	Manual Tax Repair Expense					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
122	Section 263(a)					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
123	Tax Repair Expense					($1,838.10)	$0.00		$0.00			$0.00		($1,838.10)	$0.00
124	Taxable CIAC					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
125															
126	Total Book Tax Differences					($584,566.59)	$0.00		$0.00			$0.00		($584,566.59)	$0.00
127	Ordinary Retirements					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
128															
129	Memo					($0.91)	$0.00		$0.00			$0.00		($0.91)	$0.00
130	Tax Balance					$11,847,627.66	$0.00		$0.00			$0.00		$11,847,627.66	$0.00
131															
132	Tax Reserve					$3,911,212.95	$13,750.84		$0.00			$0.00		$3,924,963.78	$0.00
133	Net Value:					$7,936,414.71	($13,750.84)		$0.00			$0.00		$7,922,663.88	$0.00
134	Roll Forward Schedule														

	A	B	C	D	E	F	G
1				NorthWestern Energy			
2				Battle Creek Natural Gas Properties			
3							
4				Capital Structure			
5							
6							
7							
8							
9				Percent	Rate of		
10		Capital Structure	Rate	Capitalization	Return		
11		Equity	10.35%	46.79%	4.84%		
12		Debt	4.67%	53.21%	2.49%		
13							
14		Total		100.00%	7.33%		

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1			NorthWestern Energy														
2			Battle Creek Natural Gas Properties									Forecast					
3						Sales &						Escalation					
4						Admin.			Allocation of			Rate					
5			Projected Costs			& General	Labor		Gas Production	One-Time		2.50%					
6				2015 Actuals		Adjustment	Adjustment	Property Tax	Administration	Adjustments		Test Period		2016	2017	2018	2019
7		OPERATIONS & MAINTENANCE:															
8			Production Expenses														
9																	
10		Production & Gathering-Operation															
11		750	Supervision & Engineering	9,713			277		30,327			40,317		41,325	42,358	43,417	44,502
12		751	Maps & Records	-			-		-			-		-	-	-	-
13		752	Gas Wells Expenses	229,927			5,434		-			235,361		241,245	247,276	253,458	259,794
14		753	Field Lines Expenses	4,177			85		-			4,261		4,368	4,477	4,589	4,703
15		754	Field Compressor Station Expense	18,821			231		-			19,052		17,419	15,949	14,588	13,336
16		755	Field Comp. Station Fuel & Power	69,985			-		-			69,985		71,735	73,528	75,367	77,251
17		756	Field Meas. & Reg. Station Expense	6,788			16		-			6,804		6,974	7,149	7,327	7,510
18		757	Dehydration Expense	-			-		-			-		-	-	-	-
19		758	Gas Well Royalties	114,263			-		-			114,263		104,469	95,654	87,492	79,984
20		759	Other Expenses	135,361			333		548	(18,375)		117,867		120,813	123,834	126,929	130,103
21		760	Rents	50,009			-		-			50,009		51,259	52,540	53,854	55,200
22		Total Oper. Production & Gathering		639,043		-	6,375	-	30,875	(18,375)		657,918		659,608	682,765	687,021	672,384
23		Production & Gathering-Maintenance															
24		761	Supervision and Engineering	-			-		-			-		-	-	-	-
25		762	Structures and Improvements	-			-		-			-		-	-	-	-
26		763	Producing Gas Wells	7,092			7		-	(847)		6,252		6,409	6,569	6,733	6,901
27		764	Field Lines	379			5		-			384		393	403	413	424
28		765	Field Compressor Station Equipment	352			4		-			356		365	374	384	393
29		766	Field Measuring and Regulating Station Equipment	2,861			62		-			2,923		2,996	3,071	3,148	3,226
30		767	Purification Equipment	-			-		-			-		-	-	-	-
31		768	Drilling and Cleaning Equipment	-			-		-			-		-	-	-	-
32		769	Other Equipment	888			6		-			894		917	939	963	987
33		Total Maint. Production & Gathering		11,572		-	84	-	-	(847)		10,809		11,080	11,357	11,641	11,932
34		Total Production & Gathering Expenses		650,615		-	6,459	-	30,875	(19,222)		668,727		670,685	674,121	678,662	684,315
35		Distribution Operation															
36		870	Supervision & Engineering						-			-		-	-	-	-
37		874	Mains and Services						-			-		-	-	-	-
38		875	Meas. & Reg. Station-General						-			-		-	-	-	-
39		877	Meas. & Reg. Station-City Gate						-			-		-	-	-	-
40		878	Meter & House Regulator						-			-		-	-	-	-
41		879	Customer Installations						71			71		72	74	76	78
42		880	Other Expenses						9,396			9,396		9,631	9,871	10,118	10,371
43		881	Rents						-			-		-	-	-	-
44		Total Operation-Distribution		-		-	-	-	9,468	-		9,468		9,703	9,946	10,194	10,449
45			TOTAL OPER. & MAINT. EXPENSES	650,615		-	6,459	-	40,341	(19,222)		678,194		680,389	684,067	688,856	694,765
46																	
47		Customer Accounts-Operation															
48		902	Meter Reading						-			-		-	-	-	-
49		903	Customer Records & Collection						33,772			33,772		34,616	35,481	36,368	37,278
50		904	Uncollectible Accounts						5,906			5,906		6,054	6,205	6,360	6,519
51		905	Miscellaneous Customer Accounts						15			15		15	15	16	16
52		Total Customer Accounts Expenses		-		-	-	-	39,693	-		39,693		40,685	41,702	42,745	43,813
53																	
54		Customer Service-Operation															
55		908	Customer Assistance						31,664			31,664		32,456	33,267	34,099	34,951
56		909	Inform. & Instructional Advertising						8,193			8,193		8,398	8,608	8,823	9,044
57		Total Customer Service & Information Exp.		-		-	-	-	39,857	-		39,857		40,854	41,875	42,922	43,995
58																	
59		Admin. & General - Operation															
60		920	Administrative & General Salaries						252,320			252,320		258,628	265,094	271,721	278,515
61		921	Office Supplies & Expenses						62,566			62,566		64,130	65,734	67,377	69,061
62		922	Administrative Exp. Transferred-Cr.						(31,752)			(31,752)		(32,546)	(33,360)	(34,194)	(35,048)
63		923	Outside Services Employed						60,693			60,693		62,210	63,766	65,360	66,994
64		924	Property Insurance			-			194			194		199	204	209	215
65		925	Injuries & Damages			871			57,612	18,375		76,858		78,780	80,749	82,768	84,837
66		926	Employee Pensions & Benefits						12,776			12,776		13,095	13,422	13,758	14,102
67		928	Regulatory Commission Expenses						1,437			1,437		1,473	1,509	1,547	1,586
68		930	Miscellaneous General Expenses						16,851			16,851		17,272	17,704	18,146	18,600
69		931	Rents						11,288			11,288		11,570	11,859	12,156	12,459
70		Total Operation-Admin. & General		-		871	-	-	443,985	18,375		463,231		474,812	486,682	498,849	511,320
71		Admin. & General - Maintenance															
72		935	General Plant						20,054			20,054		20,555	21,069	21,596	22,135
73		Total Admin. & General Expenses		-		871	-	-	543,588	18,375		562,634		576,905	591,328	606,111	621,264
74																	
75																	
76		408.1	Payroll Taxes	18,602			452		2,542			21,596		22,136	22,689	23,256	23,838
77			Vehicle Taxes	626								626		641	657	674	690
78			Property Taxes	24,197				2,898				27,095		27,095	27,772	28,467	29,178
79			Production Taxes	61,465								61,465		56,197	51,455	47,065	43,026
80			MPSC/MCC Taxes	9,636								9,636		12,144	11,959	11,866	11,811
81			Other Taxes	7,191								7,191		7,371	7,555	7,744	7,938
82																	
83		457110	Non-operating	33,612								33,612		30,731	28,138	25,737	23,529
84		469610	Miscellaneous Revenues	115,677								115,677		108,000	108,000	108,000	108,000
85		459100	Gathering Revenues	-								-		-	-	-	-
86		492200	Liquid Sales	-								-		-	-	-	-
87				149,289		-	-	-	-	-		149,289		138,731	136,138	133,737	131,529
88																	
89			Depreciation & Amortization						51,037			51,037		51,037	51,037	51,037	51,037
90																	
91			Pension Differential						(54,354)			(54,354)		(55,713)	(57,105)	(58,533)	(59,996)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
1	NORTHWESTERN ENERGY - MONTANA NATURAL GAS UTILITY																								
2	CALCULATION OF CASH WORKING CAPITAL DOCKET NO. D2016.9.68																								
3																									
4			Forecast Year 2016						Forecast Year 2017						Forecast Year 2018						Forecast Year 2019				
5																									
6			12 Month Ended		Net Lag		Cash		12 Month Ended		Net Lag		Cash		12 Month Ended		Net Lag		Cash		12 Month Ended		Net Lag		Cash
7			Expenses		Days [1]		Working Capital		Expenses		Days [1]		Working Capital		Expenses		Days [1]		Working Capital		Expenses		Days [1]		Working Capital
8																									
9																									
10	Operation, Maintenance and Admin. Costs		1,097,112						1,122,635						1,148,941						1,176,048				
11	Other Taxes		69,367						70,632						72,006						73,455				
12	State Income Taxes		46,744						45,776						45,712						45,759				
13	Federal Income Taes		226,017						221,335						221,027						221,253				
14	Sub-Total		1,439,261		-65.21		-257,135		1,460,378		-65.21		-260,908		1,487,686		-65.21		-265,786		1,516,514		-65.21		-270,937
15																									
16																									
17	Rate Base Without Cash Working Capital		8,793,685						8,442,470						8,131,586						7,845,837				
18																									
19	Weighted Cost of Debt [2]		2.49%						2.49%						2.49%						2.49%				
20																									
21	Interest Expense in Return		218,963		-48.41		-29,041		210,218		-48.41		-27,881		202,476		-48.41		-26,854		195,361		-48.41		-25,911
22																									
23	Total Cash Working Capital						-286,176						-288,789						-292,641						-296,847
24																									
25																									
26	[1]Net Lag Days from MAC 2016 Lead/Lag Study Update																								
27																									
28	[2]Weighted Cost of Debt Proposed in D2016.9.68																								

Estimated net gas production MMCF

Year	Battle Creek	Bear Paw	South Bear Paw	Wilbanks	Black Hills
2015	350	1008	4286	12	93
2016	320	862	4014	11	112
2017	293	768	3676	10	100
2018	268	680	3382	9	90
2019	245	608	3122	8	82

Year	Battle Creek	decline	Bear Paw	decline	South Bear Paw	decline
2015	350		1101		4298	
2016	320	8.6%	974	11.5%	4025	6.4%
2017	293	8.4%	868	10.9%	3686	8.4%
2018	268	8.5%	770	11.3%	3391	8.0%
2019	245	8.6%	690	10.4%	3130	7.7%

The production in each area will decline and so will the Compression by others in Acct. 754

Battle Creek	A/C 754	Normalized Expense
Year 2015	$ 19,052.05	
Normalized Adj:		
2016	$ (1,633.03)	$ 17,419.02
2017	$ (1,469.73)	$ 15,949.29
2018	$ (1,360.86)	$ 14,588.43
2019	$ (1,251.99)	$ 13,336.44

Bear Paw (NFR)	A/C 754 Total	[1]Compression by Others	Compression Operations
Year 2015	$ 1,200,552.38	$ 857,702.62	$ 342,849.76
2016 Willow Creek Adj.	$ (89,856.00)		$ (89,856.00)
	$ 1,110,696.38	$ 857,702.62	$ 252,993.76
Production Reduction Adjustment 2016	$ (98,935.72)	$ (98,935.72)	
Test Year 2016	$ 1,011,760.66	$ 758,766.90	$ 252,993.76
2017 Willow Creek Adj.	$ (89,856.00)		$ (89,856.00)
	$ 921,904.66	$ 758,766.90	$ 163,137.76
Production Reduction Adjustment 2017	$ (82,576.27)	$ (82,576.27)	
Test Year 2017	$ 839,328.38	$ 676,190.62	$ 163,137.76
Production Reduction Adjustment 2018	$ (76,344.10)	$ (76,344.10)	
Test Year 2018	$ 762,984.28	$ 599,846.52	$ 163,137.76
Production Reduction Adjustment 2019	$ (62,321.72)	$ (62,321.72)	
Test Year 2019	$ 700,662.56	$ 537,524.80	$ 163,137.76

[1]Compression by other in Order No. 01BPF754COTH.

South Bear Paw (Devon)	A/C 754 Total	[1]Compression by Others	Compression Operations
Year 2015	$ -	$ 3,678,329.00	$ (3,678,329.00)
	$ -	$ 3,678,329.00	$ (3,678,329.00)
Production Reduction Adjustment 2016	$ (233,639.79)	$ (233,639.79)	
Test Year 2016	$ (233,639.79)	$ 3,444,689.21	$ (3,678,329.00)
	$ (233,639.79)	$ 3,444,689.21	$ (3,678,329.00)
Production Reduction Adjustment 2017	$ (290,124.13)	$ (290,124.13)	
Test Year 2017	$ (523,763.92)	$ 3,154,565.08	$ (3,678,329.00)
Production Reduction Adjustment 2018	$ (252,467.90)	$ (252,467.90)	
Test Year 2018	$ (776,231.83)	$ 2,902,097.17	$ (3,678,329.00)
Production Reduction Adjustment 2019	$ (223,369.91)	$ (223,369.91)	
Test Year 2019	$ (999,601.74)	$ 2,678,727.26	$ (3,678,329.00)

[1]Compression by other in Order No. 01BPF754COTH.

	A	B	C	D	E	F	G	H	I	J	K	L
1	NORTHWESTERN ENERGY - MONTANA GAS OPERATIONS - BATTLE CREEK RATE BASE											
2												
3				AVE.			AVE.		DEFERRED INCOME TAXES			AVE.
4			PLANT BALANCE	PLANT BALANCE		DEPR RESERVE	DEPR RESERVE		NET ACTIVITY	ENDING BALANCE		DEFERRED TAX
5												
6	DECEMBER	2014	$ 12,392,361			$ 2,910,957				$ 311,387		
7												
8	JANUARY	2015	$ 12,392,361			$ 2,966,648			$ (1,101)	$ 310,286		
9												
10	FEBRUARY	2015	$ 12,392,360			$ 3,039,864			$ (1,101)	$ 309,185		
11												
12	MARCH	2015	$ 12,392,360			$ 3,090,528			$ (1,101)	$ 308,084		
13												
14	APRIL	2015	$ 12,392,360			$ 3,146,405			$ (1,101)	$ 306,984		
15												
16	MAY	2015	$ 12,392,360			$ 3,200,723			$ (1,101)	$ 305,883		
17												
18	JUNE	2015	$ 12,392,342			$ 3,254,594			$ (1,101)	$ 304,782		
19												
20	JULY	2015	$ 12,392,342			$ 3,308,164			$ (1,101)	$ 303,681		
21												
22	AUGUST	2015	$ 12,392,342			$ 3,362,053			$ (1,101)	$ 302,581		
23												
24	SEPTEMBER	2015	$ 12,392,342			$ 3,417,267			$ (1,101)	$ 301,480		
25												
26	OCTOBER	2015	$ 12,392,563			$ 3,468,946			$ (1,101)	$ 300,379		
27												
28	NOVEMBER	2015	$ 12,392,563			$ 3,523,044			$ (1,101)	$ 299,278		
29												
30	DECEMBER	2015	$ 12,432,195	$ 12,395,450		$ 3,573,124	$ 3,250,948		$ (1,101)	$ 298,178		$ 304,782
31												
32	JANUARY	2016	$ 12,435,116			$ 3,613,083			$ (1,877)	$ 296,300		
33												
34	FEBRUARY	2016	$ 12,438,037			$ 3,653,043			$ (1,877)	$ 294,423		
35												
36	MARCH	2016	$ 12,440,958			$ 3,693,002			$ (1,877)	$ 292,546		
37												
38	APRIL	2016	$ 12,443,880			$ 3,732,962			$ (1,877)	$ 290,669		
39												
40	MAY	2016	$ 12,446,801			$ 3,772,922			$ (1,877)	$ 288,791		
41												
42	JUNE	2016	$ 12,449,722			$ 3,812,881			$ (1,877)	$ 286,914		
43												
44	JULY	2016	$ 12,452,643			$ 3,852,841			$ (1,877)	$ 285,037		
45												
46	AUGUST	2016	$ 12,455,564			$ 3,892,800			$ (1,877)	$ 283,160		
47												
48	SEPTEMBER	2016	$ 12,458,485			$ 3,932,760			$ (1,877)	$ 281,283		
49												
50	OCTOBER	2016	$ 12,461,406			$ 3,972,720			$ (1,877)	$ 279,405		
51												
52	NOVEMBER	2016	$ 12,464,327			$ 4,012,679			$ (1,877)	$ 277,528		
53												
54	DECEMBER	2016	$ 12,467,248	$ 12,449,722		$ 4,052,639	$ 3,812,881		$ (1,877)	$ 275,651		$ 286,914
55												
56	JANUARY	2017	$ 12,470,134			$ 4,089,089			$ (1,898)	$ 273,753		
57												
58	FEBRUARY	2017	$ 12,473,019			$ 4,125,540			$ (1,898)	$ 271,855		
59												
60	MARCH	2017	$ 12,475,904			$ 4,161,990			$ (1,898)	$ 269,957		
61												
62	APRIL	2017	$ 12,478,789			$ 4,198,441			$ (1,898)	$ 268,059		
63												
64	MAY	2017	$ 12,481,675			$ 4,234,892			$ (1,898)	$ 266,161		
65												
66	JUNE	2017	$ 12,484,560			$ 4,271,342			$ (1,898)	$ 264,263		
67												
68	JULY	2017	$ 12,487,445			$ 4,307,793			$ (1,898)	$ 262,365		
69												
70	AUGUST	2017	$ 12,490,331			$ 4,344,243			$ (1,898)	$ 260,467		
71												
72	SEPTEMBER	2017	$ 12,493,216			$ 4,380,694			$ (1,898)	$ 258,568		
73												
74	OCTOBER	2017	$ 12,496,101			$ 4,417,144			$ (1,898)	$ 256,670		
75												
76	NOVEMBER	2017	$ 12,498,986			$ 4,453,595			$ (1,898)	$ 254,772		
77												
78	DECEMBER	2017	$ 12,501,872	$ 12,484,560		$ 4,490,045	$ 4,271,342		$ (1,898)	$ 252,874		$ 264,263
79												
80	JANUARY	2018	$ 12,505,217			$ 4,523,773			$ (1,943)	$ 250,932		
81												
82	FEBRUARY	2018	$ 12,508,562			$ 4,557,500			$ (1,943)	$ 248,989		
83												
84	MARCH	2018	$ 12,511,906			$ 4,591,227			$ (1,943)	$ 247,047		
85												
86	APRIL	2018	$ 12,515,251			$ 4,624,954			$ (1,943)	$ 245,104		
87												
88	MAY	2018	$ 12,518,596			$ 4,658,681			$ (1,943)	$ 243,161		
89												

	A	B	C	D	E	F	G	H	I	J	K	L
1	NORTHWESTERN ENERGY - MONTANA GAS OPERATIONS - BATTLE CREEK RATE BASE											
2												
3				AVE.			AVE.		DEFERRED INCOME TAXES			AVE.
4			PLANT BALANCE	PLANT BALANCE		DEPR RESERVE	DEPR RESERVE		NET ACTIVITY	ENDING BALANCE		DEFERRED TAX
90	JUNE	2018	$ 12,521,941			$ 4,692,408			$ (1,943)	$ 241,219		
91												
92	JULY	2018	$ 12,525,286			$ 4,726,135			$ (1,943)	$ 239,276		
93												
94	AUGUST	2018	$ 12,528,631			$ 4,759,863			$ (1,943)	$ 237,334		
95												
96	SEPTEMBER	2018	$ 12,531,976			$ 4,793,590			$ (1,943)	$ 235,391		
97												
98	OCTOBER	2018	$ 12,535,321			$ 4,827,317			$ (1,943)	$ 233,448		
99												
100	NOVEMBER	2018	$ 12,538,666			$ 4,861,044			$ (1,943)	$ 231,506		
101												
102	DECEMBER	2018	$ 12,542,010	$ 12,521,941		$ 4,894,771	$ 4,692,408		$ (1,943)	$ 229,563		$ 241,219
103												
104	JANUARY	2019	$ 12,543,816			$ 4,926,014			$ (1,960)	$ 227,604		
105												
106	FEBRUARY	2019	$ 12,545,621			$ 4,957,256			$ (1,960)	$ 225,644		
107												
108	MARCH	2019	$ 12,547,426			$ 4,988,499			$ (1,960)	$ 223,685		
109												
110	APRIL	2019	$ 12,549,231			$ 5,019,742			$ (1,960)	$ 221,725		
111												
112	MAY	2019	$ 12,551,036			$ 5,050,984			$ (1,960)	$ 219,765		
113												
114	JUNE	2019	$ 12,552,842			$ 5,082,227			$ (1,960)	$ 217,806		
115												
116	JULY	2019	$ 12,554,647			$ 5,113,470			$ (1,960)	$ 215,846		
117												
118	AUGUST	2019	$ 12,556,452			$ 5,144,712			$ (1,960)	$ 213,887		
119												
120	SEPTEMBER	2019	$ 12,558,257			$ 5,175,955			$ (1,960)	$ 211,927		
121												
122	OCTOBER	2019	$ 12,560,062			$ 5,207,197			$ (1,960)	$ 209,968		
123												
124	NOVEMBER	2019	$ 12,561,867			$ 5,238,440			$ (1,960)	$ 208,008		
125												
126	DECEMBER	2019	$ 12,563,673	$ 12,552,842		$ 5,269,683	$ 5,082,227		$ (1,960)	$ 206,049		$ 217,806

	A	B	C	D	E	F
1	**NorthWestern Energy**					
2	**Bear Paw (NFR) Natural Gas Properties**					
3	**Docket No. D2016.9.68**					
4						
5	**Forecasted - Revenue Requirement**					
6			2016	2017	2018	2019
7	**Utility Plant in Service**					
8	Plant in Service - Bear Paw (NFR)		$ 17,598,240	$ 17,647,486	$ 17,700,325	$ 17,744,005
9	Common Plant		949,701	1,056,186	1,162,672	1,269,157
10	Total Plant		$ 18,547,941	$ 18,703,672	$ 18,862,997	$ 19,013,162
11						
12	Less:					
13	Accumulated Depreciation & Depletion		$ 5,595,618	$ 6,594,240	$ 7,496,441	$ 8,314,602
14	Accumulated Depreciation - Common Plant		374,029	415,967	457,905	499,843
15	Total Accumulated Depreciation and Depletion		$ 5,969,648	$ 7,010,207	$ 7,954,346	$ 8,814,445
16						
17	Net Plant		$ 12,578,294	$ 11,693,465	$ 10,908,651	$ 10,198,716
18						
19	Less: Customer Contributed Capital					
20	Deferred Income Taxes					
21	Accelerated Tax Depreciation		$ (350,161)	$ (374,987)	$ (403,726)	$ (433,446)
22						
23	Plus: Working Capital					
24	Gross Cash Requirements		$ (685,177)	$ (659,164)	$ (651,209)	$ (646,687)
25						
26	**Average Rate Base**		$ 12,243,278	$ 11,409,287	$ 10,661,168	$ 9,985,475
27						
28	**Rate of Return**		7.33%	7.33%	7.33%	7.33%
29						
30	***Authorized Return (Avg. Rate Base * Rate of Return)***		$ 897,432	$ 836,301	$ 781,464	$ 731,935
31						
32	***Cost of Service:***					
33	Operation & Maintenance Expenses		$ 2,327,170	$ 2,155,971	$ 2,083,478	$ 2,030,068
34	Administrative & General		822,195	842,750	863,819	885,414
35	Depreciation Expense		166,520	167,884	168,346	168,808
36	Depreciation Common Expense		72,108	82,455	94,287	107,817
37	Depletion Expense		961,023	859,992	766,355	690,988
38	Property & Other Taxes		331,979	331,875	332,454	334,366
39	MPSC & MCC Revenue Tax	0.49%	23,985	22,898	22,369	22,000
40	Misc. Revenues		(180,000)	(180,000)	(180,000)	(180,000)
41	Non-operating Revenues		(26,863)	(23,940)	(21,237)	(19,030)
42	Gathering Revenues		(570,058)	(508,019)	(450,662)	(403,840)
43	Deferred Income Taxes		(21,519)	(28,134)	(29,345)	(30,093)
44	Current Income Taxes		$ 390,133	$ 379,695	$ 370,401	$ 363,350
45	***Total Cost of Service***		$ 4,296,673	$ 4,103,428	$ 4,020,265	$ 3,969,849
46						
47	***Less Variable Costs:***					
48	Production Taxes		$ 62,797	$ 55,963	$ 49,645	$ 44,487
49	Royalty Expense		236,509	210,770	186,973	167,547
50	***Total Variable Cost of Service***		$ 299,306	$ 266,733	$ 236,618	$ 212,034
51						
52	**Total Fixed Revenue Requirement (Ln 30 + Ln 45 - Ln 50)**		$ 4,894,799	$ 4,672,996	$ 4,565,111	$ 4,489,750
53						
54	**Normalized Load (Dkt)**		19,261,583	19,417,978	19,575,783	19,735,012
55	**Fixed Cost Unit Rate Per Year**		$ 0.2541	$ 0.2407	$ 0.2332	$ 0.2275

	A	B	C	D	E	F
1	**NorthWestern Energy**					
2	**Bear Paw (NFR) Natural Gas Properties**					
3	**Docket No. D2016.9.68**					
4						
5	**Forecasted - Revenue Requirement**					
6			2016	2017	2018	2019
56						
57						
58						
59	***Income Tax Computation:***	**Rate**				
60	Revenues		$ 4,894,799	$ 4,672,996	$ 4,565,111	$ 4,489,750
61	Operating Expenses		2,090,662	1,945,202	1,896,505	1,862,521
62	Administrative & General		822,195	842,750	863,819	885,414
63	Miscellaneous Revenues		(180,000)	(180,000)	(180,000)	(180,000)
64	Non-operating Revenues		(26,863)	(23,940)	(21,237)	(19,030)
65	Gathering Revenues		(570,058)	(508,019)	(450,662)	(403,840)
66	Property & Other Taxes		269,182	275,912	282,809	289,880
67	MPSC & MCC Revenue Tax		23,985	22,898	22,369	22,000
68	Tax Depreciation/Depletion		1,066,060	947,495	850,858	773,816
69	Tax Depreciation Common		104,280	102,609	94,783	87,850
70	Montana Corporate Income Tax		66,859	65,070	63,477	62,269
71	Interest Expense (Based on Avg. Rate Base)	2.49%	304,858	284,091	265,463	248,638
72	Federal Taxable Income		$ 923,641	$ 898,928	$ 876,926	$ 860,233
73						
74	Federal Income Tax @ 35%	35.00%	323,274	314,625	306,924	301,082
75						
76	Federal Current Tax Expense		323,274	314,625	306,924	301,082
77						
78	Federal Taxable Income		$ 923,641	$ 898,928	$ 876,926	$ 860,233
79	Montana Corporate Income Tax		66,859	65,070	63,477	62,269
80	Montana Corporate Taxable		$ 990,500	$ 963,998	$ 940,403	$ 922,502
81						
82	Montana Corporate Income Tax @ 6.75%	6.75%	66,859	65,070	63,477	62,269
83						
84	Montana Current Tax Expense		66,859	65,070	63,477	62,269
85						
86	Total Current Income Tax Expense		$ 390,133	$ 379,695	$ 370,401	$ 363,350
87						
88	***Deferred Income Tax Computation:***	**Rate**				
89	***Accelerated Tax Depreciation***					
90	Tax Depreciation		$ 1,066,060	$ 947,495	$ 850,858	$ 773,816
91	Less Book Depreciation/Depletion		1,127,543	1,027,877	934,701	859,797
92	Net Deferred Taxable Income		$ (61,483)	$ (80,382)	$ (83,843)	$ (85,981)
93	Federal Income Tax Rate		35%	35%	35%	35%
94	Federal Deferred Income Tax Expense-Accelerated Tx Deprec		$ (21,519)	$ (28,134)	$ (29,345)	$ (30,093)

	A	B	C	D	E	F	G	H
1	Bear Paw (NFR)							
2	Forecasted Depreciation							
3	2016-2019							
4				50%	50%	40%	30%	
5	Tax Class	Additions		2016	2017	2018	2019	Total
6								
7	*DEPLETION G325.2, G330, G331*	-		961,023	859,992	766,355	690,988	3,278,359
8								
9	*MACRS 15 G327, G328, G332, G333, G334.1, G334.2*							
10	2016	15,148		7,953	720	648	583	9,903
11	2017	15,148			7,953	720	648	9,320
12	2018	15,148				6,514	863	7,377
13	2019	15,148					5,075	5,075
14								
15	*MACRS 5 G392.2, G392.3, G392.7*							-
16	2016	87		52	14	8	5	80
17	2017	87			52	14	8	75
18	2018	87				45	17	62
19	2019	87					38	38
20								
21	*MACRS 7 G394*							
22	2016	75		43	9	7	5	63
23	2017	75			43	9	7	58
24	2018	75				36	11	47
25	2019	75					30	30
26								
27	2015 AND EARLIER VINTAGES FROM PTAX (Excl Depletion Expense)	-		96,988	78,712	76,503	75,538	327,741
28	TOTAL	61,241		1,066,060	947,495	850,858	773,816	3,638,228

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1							Rpt # 30		2016		7/28/2016 15:06				
2															
3															
4								Grouped By:		Total Tax Classes					
5	Tax Class Rollup					Balance	Additions		Dispositions			Transfers		Balance	Memo
6						Begin of Period								End of Period	
7															
8	Total Tax Classes														
9															
10	Total Cost: Book					$17,356,477.56	$0.00		$0.00			$0.00		$17,356,477.56	$0.00
11	Book Tax Differences														
12	AFUDC Debt					($1,699.45)	$0.00		$0.00			$0.00		($1,699.45)	$0.00
13	AFUDC Equity					($2,887.04)	$0.00		$0.00			$0.00		($2,887.04)	$0.00
14	Bonus Depr Reduction					$231,174.67	$0.00		$0.00			$0.00		$231,174.67	$0.00
15	Capitalized Interest					$7,140.06	$0.00		$0.00			$0.00		$7,140.06	$0.00
16	Manual Tax Repair Expense					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
17	Tax Repair Expense					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
18	Taxable CIAC					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
19															
20	Total Book Tax Differences					$233,728.24	$0.00		$0.00			$0.00		$233,728.24	$0.00
21	Ordinary Retirements					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
22															
23	Memo					($131.60)	$0.00		$0.00			$0.00		($131.60)	$0.00
24	Tax Balance					$17,590,074.20	$0.00		$0.00			$0.00		$17,590,074.20	$0.00
25															
26	Tax Reserve					$5,043,441.76	$96,988.39		$0.00			$0.00		$5,140,430.15	$0.00
27	Net Value:					$12,546,632.44	($96,988.39)		$0.00			$0.00		$12,449,644.05	$0.00
28							Rpt # 30		2017		7/28/2016 15:06				
29															
30															
31								Grouped By:		Total Tax Classes					
32	Tax Class Rollup					Balance	Additions		Dispositions			Transfers		Balance	Memo
33						Begin of Period								End of Period	
34															
35	Total Tax Classes														
36															
37	Total Cost: Book					$17,356,477.56	$0.00		$0.00			$0.00		$17,356,477.56	$0.00
38	Book Tax Differences														
39	AFUDC Debt					($1,699.45)	$0.00		$0.00			$0.00		($1,699.45)	$0.00
40	AFUDC Equity					($2,887.04)	$0.00		$0.00			$0.00		($2,887.04)	$0.00
41	Bonus Depr Reduction					$231,174.67	$0.00		$0.00			$0.00		$231,174.67	$0.00
42	Capitalized Interest					$7,140.06	$0.00		$0.00			$0.00		$7,140.06	$0.00
43	Manual Tax Repair Expense					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
44	Tax Repair Expense					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
45	Taxable CIAC					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
46															
47	Total Book Tax Differences					$233,728.24	$0.00		$0.00			$0.00		$233,728.24	$0.00
48	Ordinary Retirements					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
49															
50	Memo					($131.60)	$0.00		$0.00			$0.00		($131.60)	$0.00
51	Tax Balance					$17,590,074.20	$0.00		$0.00			$0.00		$17,590,074.20	$0.00
52															
53	Tax Reserve					$5,140,430.15	$78,711.80		$0.00			$0.00		$5,219,141.95	$0.00
54	Net Value:					$12,449,644.05	($78,711.80)		$0.00			$0.00		$12,370,932.25	$0.00
55	Roll Forward Schedule														
56	MTU - MTU-Northwestern Energy														
57							Rpt # 30		2018		7/28/2016 15:06				
58															
59															
60								Grouped By:		Total Tax Classes					
61	Tax Class Rollup					Balance	Additions		Dispositions			Transfers		Balance	Memo
62						Begin of Period								End of Period	
63															
64	Total Tax Classes														
65															
66	Total Cost: Book					$17,356,477.56	$0.00		$0.00			$0.00		$17,356,477.56	$0.00
67	Book Tax Differences														
68	AFUDC Debt					($1,699.45)	$0.00		$0.00			$0.00		($1,699.45)	$0.00
69	AFUDC Equity					($2,887.04)	$0.00		$0.00			$0.00		($2,887.04)	$0.00
70	Bonus Depr Reduction					$231,174.67	$0.00		$0.00			$0.00		$231,174.67	$0.00
71	Capitalized Interest					$7,140.06	$0.00		$0.00			$0.00		$7,140.06	$0.00
72	Manual Tax Repair Expense					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
73	Tax Repair Expense					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
74	Taxable CIAC					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
75															
76	Total Book Tax Differences					$233,728.24	$0.00		$0.00			$0.00		$233,728.24	$0.00
77	Ordinary Retirements					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
78															
79	Memo					($131.60)	$0.00		$0.00			$0.00		($131.60)	$0.00
80	Tax Balance					$17,590,074.20	$0.00		$0.00			$0.00		$17,590,074.20	$0.00
81															
82	Tax Reserve					$5,219,141.95	$76,503.21		$0.00			$0.00		$5,295,645.16	$0.00
83	Net Value:					$12,370,932.25	($76,503.21)		$0.00			$0.00		$12,294,429.04	$0.00
84	Roll Forward Schedule														
85							Rpt # 30		2019		7/28/2016 15:06				
86															
87															
88								Grouped By:		Total Tax Classes					
89	Tax Class Rollup					Balance	Additions		Dispositions			Transfers		Balance	Memo
90						Begin of Period								End of Period	
91															
92	Total Tax Classes														
93															
94	Total Cost: Book					$17,356,477.56	$0.00		$0.00			$0.00		$17,356,477.56	$0.00
95	Book Tax Differences														
96	AFUDC Debt					($1,699.45)	$0.00		$0.00			$0.00		($1,699.45)	$0.00
97	AFUDC Equity					($2,887.04)	$0.00		$0.00			$0.00		($2,887.04)	$0.00
98	Bonus Depr Reduction					$231,174.67	$0.00		$0.00			$0.00		$231,174.67	$0.00
99	Capitalized Interest					$7,140.06	$0.00		$0.00			$0.00		$7,140.06	$0.00
100	Manual Tax Repair Expense					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
101	Tax Repair Expense					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
102	Taxable CIAC					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
103															
104	Total Book Tax Differences					$233,728.24	$0.00		$0.00			$0.00		$233,728.24	$0.00
105	Ordinary Retirements					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
106															
107	Memo					($131.60)	$0.00		$0.00			$0.00		($131.60)	$0.00
108	Tax Balance					$17,590,074.20	$0.00		$0.00			$0.00		$17,590,074.20	$0.00
109															
110	Tax Reserve					$5,295,645.16	$75,537.71		$0.00			$0.00		$5,371,182.87	$0.00
111	Net Value:					$12,294,429.04	($75,537.71)		$0.00			$0.00		$12,218,891.33	$0.00
112	Page 1 of 1														

	A	B	C	D	E	F	G
1				**NorthWestern Energy**			
2				**Bear Paw (NFR) Natural Gas Properties**			
3							
4				**Capital Structure**			
5							
6							
7							
8							
9				**Percent**	**Rate of**		
10		**Capital Structure**	**Rate**	**Capitalization**	**Return**		
11		Equity	10.35%	46.79%	4.84%		
12		Debt	4.67%	53.21%	2.49%		
13							
14		Total		100.00%	7.33%		

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1			NorthWestern Energy														
2			Bear Paw (NFR) Natural Gas Properties									Forecast					
3						Sales &						Escalation					
4			Projected Costs			Admin.			Allocation of			Rate					
5						& General	Labor		Gas Production	One-Time		2.50%					
6				2015 Actuals		Adjustment	Adjustment	Property Tax	Administration	Adjustments		Test Period		2016	2017	2018	2019
7		OPERATIONS & MAINTENANCE:															
8			Production Expenses														
9																	
10		Production & Gathering-Operation															
11		750	Supervision & Engineering	14,821			406		46,995			62,222		63,777	65,372	67,006	68,681
12		751	Maps & Records	-			-		-			-		-	-	-	-
13		752	Gas Wells Expenses	258,045			6,309		-			264,354		270,963	277,737	284,680	291,797
14		753	Field Lines Expenses	4,040			59		-			4,099		4,201	4,306	4,414	4,524
15		754	Field Compressor Station Expense	1,196,019			4,534		-			1,200,552		1,011,761	839,328	762,084	700,663
16		755	Field Comp. Station Fuel & Power	(48,522)			-		-			(48,522)		(49,735)	(50,979)	(52,253)	(53,559)
17		756	Field Meas. & Reg. Station Expense	54,692			951		-			55,642		57,033	58,459	59,921	61,419
18		757	Dehydration Expense	699			11		-			710		728	746	765	784
19		758	Gas Well Royalties	267,347			-		-			267,347		236,509	210,770	188,073	167,547
20		759	Other Expenses	371,386			4,640		849	(45,906)		330,970		339,244	347,725	356,418	365,328
21		760	Rents	129,262			-		-			129,262		132,494	135,808	139,201	142,681
22		Total Oper. Production & Gathering		2,247,789		-	16,909	-	47,844	(45,906)		2,266,636		2,066,975	1,889,271	1,810,109	1,749,866
23		Production & Gathering-Maintenance															
24		761	Supervision and Engineering	-			-		-			-		-	-	-	-
25		762	Structures and Improvements	-			-		-			-		-	-	-	-
26		763	Producing Gas Wells	4,278			78		-			4,352		4,460	4,572	4,686	4,803
27		764	Field Lines	102,750			673		-	(55,645)		47,778		48,972	50,196	51,451	52,738
28		765	Field Compressor Station Equipment	173,888			1,552		-			175,439		179,825	184,321	188,929	193,652
29		766	Field Measuring and Regulating Station Equipment	5,166			60		-			5,226		5,357	5,491	5,628	5,769
30		767	Purification Equipment	6,000			17		-			6,017		6,168	6,322	6,480	6,642
31		768	Drilling and Cleaning Equipment	-			-		-			-		-	-	-	-
32		769	Other Equipment	388			-		-			388		377	386	396	406
33		Total Maint. Production & Gathering		292,448		-	2,377	-	-	(55,645)		239,180		245,160	251,289	257,571	264,010
34		Total Production & Gathering Expenses		2,540,237		-	19,286	-	47,844	(101,551)		2,505,816		2,312,134	2,140,559	2,067,680	2,013,876
35		Distribution Operation															
36		870	Supervision & Engineering						-			-		-	-	-	-
37		874	Mains and Services						-			-		-	-	-	-
38		875	Meas. & Reg. Station-General						-			-		-	-	-	-
39		877	Meas. & Reg. Station-City Gate						-			-		-	-	-	-
40		878	Meter & House Regulator						-			-		-	-	-	-
41		879	Customer Installations						109			109		112	115	118	121
42		880	Other Expenses						14,560			14,560		14,924	15,297	15,679	16,071
43		881	Rents						-			-		-	-	-	-
44		Total Operation-Distribution		-		-	-	-	14,669	-		14,669		15,036	15,412	15,797	16,192
45			TOTAL OPER. & MAINT. EXPENSES	2,540,237		-	19,286	-	62,514	(101,551)		2,520,486		2,327,170	2,155,971	2,083,478	2,030,068
46																	
47		Customer Accounts-Operation															
48		902	Meter Reading						-			-		-	-	-	-
49		903	Customer Records & Collection						52,333			52,333		53,642	54,983	56,357	57,766
50		904	Uncollectible Accounts						9,152			9,152		9,381	9,616	9,856	10,103
51		905	Miscellaneous Customer Accounts						23			23		24	25	25	25
52		Total Customer Accounts Expenses		-		-	-	-	61,509	-		61,509		63,046	64,622	66,238	67,894
53																	
54		Customer Service-Operation															
55		908	Customer Assistance						49,067			49,067		50,294	51,551	52,840	54,161
56		909	Inform. & Instructional Advertising						12,696			12,696		13,014	13,339	13,673	14,015
57		Total Customer Service & Information Exp.		-		-	-	-	61,764	-		61,764		63,308	64,891	66,513	68,176
58																	
59		Admin. & General - Operation															
60		920	Administrative & General Salaries						391,002			391,002		400,777	410,796	421,066	431,593
61		921	Office Supplies & Expenses						96,954			96,954		99,378	101,862	104,409	107,019
62		922	Administrative Exp. Transferred-Cr.						(49,204)			(49,204)		(50,434)	(51,695)	(52,987)	(54,312)
63		923	Outside Services Employed						94,052			94,052		96,403	98,813	101,283	103,815
64		924	Property Insurance						301			301		309	317	325	333
65		925	Injuries & Damages			(1,893)			89,277	45,906		133,290		136,622	140,038	143,538	147,127
66		926	Employee Pensions & Benefits						19,798			19,798		20,292	20,800	21,320	21,853
67		928	Regulatory Commission Expenses						2,226			2,226		2,282	2,339	2,397	2,457
68		930	Miscellaneous General Expenses						26,112			26,112		26,765	27,434	28,120	28,823
69		931	Rents						17,492			17,492		17,929	18,377	18,836	19,307
70		Total Operation-Admin. & General		-		(1,893)	-	-	688,009	45,906		732,022		750,322	769,081	788,308	808,015
71		Admin. & General - Maintenance															
72		935	General Plant						31,076			31,076		31,852	32,649	33,465	34,302
73		Total Admin. & General Expenses		-		(1,893)	-	-	842,357	45,906		886,370		908,529	931,242	954,523	978,386
74																	
75																	
76		408.1	Payroll Taxes	46,959			1,350		3,939			52,248		53,554	54,893	56,265	57,672
77			Vehicle Taxes	1,774								1,774		1,818	1,863	1,910	1,958
78			Property Taxes	149,701				64,108.75				213,810		213,810	219,155	224,634	230,250
79			Production Taxes	70,985								70,985		62,797	55,963	49,045	44,487
80			MPSC/MCC Taxes	15,083								15,083		23,985	22,898	22,369	22,000
81			Other Taxes	-								-		-	-	-	-
82																	
83		457110	Non-operating	30,366								30,366		28,863.23	23,939.72	21,236.84	19,030.42
84		489610	Miscellaneous Revenues	354,292								354,292		180,000.00	180,000.00	180,000.00	180,000.00
85		459100	Gathering Revenues	644,388								644,388		570,057.83	508,018.88	450,661.73	403,839.73
86		492200	Liquid Sales	-								-		-	-	-	-
87				1,029,046		-	-	-	-	-		1,029,046		776,921	711,958	651,899	602,870
88																	
89			Depreciation & Amortization						79,088			79,088		79,088	79,088	79,088	79,088
90																	
91			Pension Differential						(84,228)			(84,228)		(86,334)	(88,492)	(90,704)	(92,972)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
1	NORTHWESTERN ENERGY - MONTANA NATURAL GAS UTILITY																								
2	CALCULATION OF CASH WORKING CAPITAL DOCKET NO. D2016.9.68																								
3																									
4			Forecast Year 2016						Forecast Year 2017						Forecast Year 2018						Forecast Year 2019				
5																									
6			12 Month Ended		Net Lag		Cash		12 Month Ended		Net Lag		Cash		12 Month Ended		Net Lag		Cash		12 Month Ended		Net Lag		Cash
7			Expenses		Days [1]		Working Capital		Expenses		Days [1]		Working Capital		Expenses		Days [1]		Working Capital		Expenses		Days [1]		Working Capital
8																									
9																									
10	Operation, Maintenance and Admin. Costs		2,912,857						2,787,952						2,760,324						2,747,935				
11	Other Taxes		293,167						298,809						305,178						311,879				
12	State Income Taxes		66,859						65,070						63,477						62,269				
13	Federal Income Taes		323,274						314,625						306,924						301,082				-
14	Sub-Total		3,596,157		-65.21		-642,480		3,466,456		-65.21		-619,308		3,435,903		-65.21		-613,850		3,423,165		-65.21		-611,574
15																									
16																									
17	Rate Base Without Cash Working Capital		12,928,454						12,068,452						11,312,377						10,632,162				
18																									
19	Weighted Cost of Debt [2]		2.49%						2.49%						2.49%						2.49%				
20																									
21	Interest Expense in Return		321,919		-48.41		-42,696		300,504		-48.41		-39,856		281,678		-48.41		-37,359		264,741		-48.41		-35,113
22																									
23	Total Cash Working Capital						-685,177						-659,164						-651,209						-646,687
24																									
25																									
26	[1]Net Lag Days from MAC 2016 Lead/Lag Study Update																								
27																									
28	[2]Weighted Cost of Debt Proposed in D2016.9.68																								

	A	B	C	D	E	F	G	H	I	J
1										
2			Estimated net gas production MMCF							
3										
4	Year	Battle Creek	Bear Paw	South Bear Paw	Wilbanks	Black Hills				
5										
6	2015	350	1008	4286	12	93				
7	2016	320	862	4014	11	112				
8	2017	293	768	3676	10	100				
9	2018	268	680	3382	9	90				
10	2019	245	608	3122	8	82				
11										
12										
13	Year	Battle Creek	decline		Bear Paw	decline		South Bear Paw	decline	
14										
15	2015	350			1101			4298		
16	2016	320	8.6%		974	11.5%		4025	6.4%	
17	2017	293	8.4%		868	10.9%		3686	8.4%	
18	2018	268	8.5%		770	11.3%		3391	8.0%	
19	2019	245	8.6%		690	10.4%		3130	7.7%	
20										
21										
22		The production in each area will decline and so will the Compression by others in Acct. 754								
23										
24				Normalized						
25		***Battle Creek***	**A/C 754**	Expense						
26		Year 2015	$ 19,052.05							
27		Normalized Adj:								
28		2016	$ (1,633.03)	$ 17,419.02						
29		2017	$ (1,469.73)	$ 15,949.29						
30		2018	$ (1,360.86)	$ 14,588.43						
31		2019	$ (1,251.99)	$ 13,336.44						
32										
33										
34			**A/C 754**	[1]Compression	Compression			**A/C 754**	[1]Compression	Compression
35		***Bear Paw (NFR)***	Total	by Others	Operations		***South Bear Paw (Devon)***	Total	by Others	Operations
36		Year 2015	$ 1,200,552.38	$ 857,702.62	$ 342,849.76		Year 2015	$ -	$ 3,678,329.00	$ (3,678,329.00)
37										
38		*2016 Willow Creek Adj.*	$ (89,856.00)		$ (89,856.00)					
39			$ 1,110,696.38	$ 857,702.62	$ 252,993.76			$ -	$ 3,678,329.00	$ (3,678,329.00)
40		Production Reduction					Production Reduction			
41		Adjustment					Adjustment			
42		2016	$ (98,935.72)	$ (98,935.72)			2016	$ (233,639.79)	$ (233,639.79)	
43										
44		Test Year 2016	$ 1,011,760.66	$ 758,766.90	$ 252,993.76		Test Year 2016	$ (233,639.79)	$ 3,444,689.21	$ (3,678,329.00)
45										
46		*2017 Willow Creek Adj.*	$ (89,856.00)		$ (89,856.00)					
47			$ 921,904.66	$ 758,766.90	$ 163,137.76			$ (233,639.79)	$ 3,444,689.21	$ (3,678,329.00)
48		Production Reduction					Production Reduction			
49		Adjustment					Adjustment			
50		2017	$ (82,576.27)	$ (82,576.27)			2017	$ (290,124.13)	$ (290,124.13)	
51										
52		Test Year 2017	$ 839,328.38	$ 676,190.62	$ 163,137.76		Test Year 2017	$ (523,763.92)	$ 3,154,565.08	$ (3,678,329.00)
53										
54		Production Reduction					Production Reduction			
55		Adjustment					Adjustment			
56		2018	$ (76,344.10)	$ (76,344.10)			2018	$ (252,467.90)	$ (252,467.90)	
57										
58		Test Year 2018	$ 762,984.28	$ 599,846.52	$ 163,137.76		Test Year 2018	$ (776,231.83)	$ 2,902,097.17	$ (3,678,329.00)
59										
60		Production Reduction					Production Reduction			
61		Adjustment					Adjustment			
62		2019	$ (62,321.72)	$ (62,321.72)			2019	$ (223,369.91)	$ (223,369.91)	
63										
64		Test Year 2019	$ 700,662.56	$ 537,524.80	$ 163,137.76		Test Year 2019	$ (999,601.74)	$ 2,678,727.26	$ (3,678,329.00)
65										
66										
67		[1]Compression by other in Order No. 01BPF754COTH.					[1]Compression by other in Order No. 01BPF754COTH.			

	A	B	C	D	E	F	G	H	I	J	K	L
1	NORTHWESTERN ENERGY - MONTANA GAS OPERATIONS - BEAR PAW RATE BASE											
2												
3				AVE.			AVE.		DEFERRED INCOME TAXES			AVE.
4			PLANT BALANCE	PLANT BALANCE		DEPR RESERVE	DEPR RESERVE		NET ACTIVITY	ENDING BALANCE		DEFERRED TAX
5												
6	DECEMBER	2014	$ 15,959,437			$ 3,546,038				$ (656,779)		
7												
8	JANUARY	2015	$ 15,970,124			$ 3,682,552			$ 26,448	$ (630,330)		
9												
10	FEBRUARY	2015	$ 15,955,301			$ 3,802,649			$ 26,448	$ (603,882)		
11												
12	MARCH	2015	$ 15,955,301			$ 3,928,715			$ 26,448	$ (577,434)		
13												
14	APRIL	2015	$ 15,955,301			$ 4,052,046			$ 26,448	$ (550,986)		
15												
16	MAY	2015	$ 15,955,301			$ 4,172,659			$ 26,448	$ (524,538)		
17												
18	JUNE	2015	$ 15,955,301			$ 4,292,062			$ 26,448	$ (498,090)		
19												
20	JULY	2015	$ 15,955,301			$ 4,406,906			$ 26,448	$ (471,642)		
21												
22	AUGUST	2015	$ 15,951,824			$ 4,524,839			$ 26,448	$ (445,193)		
23												
24	SEPTEMBER	2015	$ 15,951,824			$ 4,640,642			$ 26,448	$ (418,745)		
25												
26	OCTOBER	2015	$ 15,951,824			$ 4,753,661			$ 26,448	$ (392,297)		
27												
28	NOVEMBER	2015	$ 15,951,824			$ 4,867,421			$ 26,448	$ (365,849)		
29												
30	DECEMBER	2015	$ 17,573,466	$ 16,080,164		$ 5,071,391	$ 4,287,814		$ 26,448	$ (339,401)		$ (498,090)
31												
32	JANUARY	2016	$ 17,577,595			$ 5,158,762			$ (1,793)	$ (341,194)		
33												
34	FEBRUARY	2016	$ 17,581,724			$ 5,246,133			$ (1,793)	$ (342,987)		
35												
36	MARCH	2016	$ 17,585,853			$ 5,333,505			$ (1,793)	$ (344,781)		
37												
38	APRIL	2016	$ 17,589,982			$ 5,420,876			$ (1,793)	$ (346,574)		
39												
40	MAY	2016	$ 17,594,111			$ 5,508,247			$ (1,793)	$ (348,367)		
41												
42	JUNE	2016	$ 17,598,240			$ 5,595,618			$ (1,793)	$ (350,161)		
43												
44	JULY	2016	$ 17,602,369			$ 5,682,990			$ (1,793)	$ (351,954)		
45												
46	AUGUST	2016	$ 17,606,498			$ 5,770,361			$ (1,793)	$ (353,747)		
47												
48	SEPTEMBER	2016	$ 17,610,627			$ 5,857,732			$ (1,793)	$ (355,540)		
49												
50	OCTOBER	2016	$ 17,614,757			$ 5,945,103			$ (1,793)	$ (357,334)		
51												
52	NOVEMBER	2016	$ 17,618,886			$ 6,032,475			$ (1,793)	$ (359,127)		
53												
54	DECEMBER	2016	$ 17,623,015	$ 17,598,240		$ 6,119,846	$ 5,595,618		$ (1,793)	$ (360,920)		$ (350,161)
55												
56	JANUARY	2017	$ 17,627,093			$ 6,198,912			$ (2,344)	$ (363,265)		
57												
58	FEBRUARY	2017	$ 17,631,172			$ 6,277,977			$ (2,344)	$ (365,609)		
59												
60	MARCH	2017	$ 17,635,250			$ 6,357,043			$ (2,344)	$ (367,954)		
61												
62	APRIL	2017	$ 17,639,329			$ 6,436,109			$ (2,344)	$ (370,298)		
63												
64	MAY	2017	$ 17,643,407			$ 6,515,175			$ (2,344)	$ (372,643)		
65												
66	JUNE	2017	$ 17,647,486			$ 6,594,240			$ (2,344)	$ (374,987)		
67												
68	JULY	2017	$ 17,651,564			$ 6,673,306			$ (2,344)	$ (377,331)		
69												
70	AUGUST	2017	$ 17,655,643			$ 6,752,372			$ (2,344)	$ (379,676)		
71												
72	SEPTEMBER	2017	$ 17,659,721			$ 6,831,437			$ (2,344)	$ (382,020)		
73												
74	OCTOBER	2017	$ 17,663,800			$ 6,910,503			$ (2,344)	$ (384,365)		
75												
76	NOVEMBER	2017	$ 17,667,878			$ 6,989,569			$ (2,344)	$ (386,709)		
77												
78	DECEMBER	2017	$ 17,671,956	$ 17,647,486		$ 7,068,635	$ 6,594,240		$ (2,344)	$ (389,054)		$ (374,987)
79												
80	JANUARY	2018	$ 17,676,685			$ 7,139,936			$ (2,445)	$ (391,499)		
81												
82	FEBRUARY	2018	$ 17,681,413			$ 7,211,237			$ (2,445)	$ (393,945)		
83												
84	MARCH	2018	$ 17,686,141			$ 7,282,538			$ (2,445)	$ (396,390)		
85												
86	APRIL	2018	$ 17,690,869			$ 7,353,839			$ (2,445)	$ (398,836)		
87												
88	MAY	2018	$ 17,695,597			$ 7,425,140			$ (2,445)	$ (401,281)		
89												

	A	B	C	D	E	F	G	H	I	J	K	L
1	NORTHWESTERN ENERGY - MONTANA GAS OPERATIONS - BEAR PAW RATE BASE											
2												
3				AVE.			AVE.		DEFERRED INCOME TAXES			AVE.
4			PLANT BALANCE	PLANT BALANCE		DEPR RESERVE	DEPR RESERVE		NET ACTIVITY	ENDING BALANCE		DEFERRED TAX
90	JUNE	2018	$ 17,700,325			$ 7,496,441			$ (2,445)	$ (403,726)		
91												
92	JULY	2018	$ 17,705,054			$ 7,567,742			$ (2,445)	$ (406,172)		
93												
94	AUGUST	2018	$ 17,709,782			$ 7,639,043			$ (2,445)	$ (408,617)		
95												
96	SEPTEMBER	2018	$ 17,714,510			$ 7,710,345			$ (2,445)	$ (411,063)		
97												
98	OCTOBER	2018	$ 17,719,238			$ 7,781,646			$ (2,445)	$ (413,508)		
99												
100	NOVEMBER	2018	$ 17,723,966			$ 7,852,947			$ (2,445)	$ (415,953)		
101												
102	DECEMBER	2018	$ 17,728,694	$ 17,700,325		$ 7,924,248	$ 7,496,441		$ (2,445)	$ (418,399)		$ (403,726)
103												
104	JANUARY	2019	$ 17,731,246			$ 7,989,307			$ (2,508)	$ (420,907)		
105												
106	FEBRUARY	2019	$ 17,733,798			$ 8,054,366			$ (2,508)	$ (423,414)		
107												
108	MARCH	2019	$ 17,736,350			$ 8,119,425			$ (2,508)	$ (425,922)		
109												
110	APRIL	2019	$ 17,738,901			$ 8,184,484			$ (2,508)	$ (428,430)		
111												
112	MAY	2019	$ 17,741,453			$ 8,249,543			$ (2,508)	$ (430,938)		
113												
114	JUNE	2019	$ 17,744,005			$ 8,314,602			$ (2,508)	$ (433,446)		
115												
116	JULY	2019	$ 17,746,556			$ 8,379,661			$ (2,508)	$ (435,953)		
117												
118	AUGUST	2019	$ 17,749,108			$ 8,444,720			$ (2,508)	$ (438,461)		
119												
120	SEPTEMBER	2019	$ 17,751,660			$ 8,509,779			$ (2,508)	$ (440,969)		
121												
122	OCTOBER	2019	$ 17,754,211			$ 8,574,838			$ (2,508)	$ (443,477)		
123												
124	NOVEMBER	2019	$ 17,756,763			$ 8,639,897			$ (2,508)	$ (445,984)		
125												
126	DECEMBER	2019	$ 17,759,315	$ 17,744,005		$ 8,704,957	$ 8,314,602		$ (2,508)	$ (448,492)		$ (433,446)

	A	B	C	D	E	F
1	**NorthWestern Energy**					
2	**South Bear Paw (Devon) Natural Gas Properties**					
3	**Docket No. D2016.9.68**					
4						
5	**Forecasted - Revenue Requirement**					
6			2016	2017	2018	2019
7	**Utility Plant In Service**					
8	Plant in Service - South Bear Paw (Devon)		$ 61,907,511	$ 62,080,748	$ 62,266,629	$ 62,420,285
9	Common Plant		3,647,350	4,056,309	4,465,268	4,874,228
10	Total Plant		$ 65,554,861	$ 66,137,057	$ 66,731,898	$ 67,294,513
11						
12	Less:					
13	Accumulated Depreciation & Depletion		$ 11,742,367	$ 15,662,979	$ 19,285,721	$ 22,649,000
14	Accumulated Depreciation - Common Plant		1,436,468	1,597,532	1,758,596	1,919,660
15	Total Accumulated Depreciation and Depletion		$ 13,178,835	$ 17,260,511	$ 21,044,317	$ 24,568,660
16						
17	Net Plant		$ 52,376,026	$ 48,876,546	$ 45,687,581	$ 42,725,853
18						
19	Less: Customer Contributed Capital					
20	Deferred Income Taxes					
21	Accelerated Tax Depreciation		$ 1,711,350	$ 1,682,559	$ 1,644,239	$ 1,597,941
22						
23	Plus: Working Capital					
24	Gross Cash Requirements		$ (1,917,275)	$ (1,859,884)	$ (1,816,054)	$ (1,779,035)
25						
26	**Average Rate Base**		$ 48,747,401	$ 45,334,103	$ 42,227,288	$ 39,348,877
27						
28	**Rate of Return**		7.33%	7.33%	7.33%	7.33%
29						
30	***Authorized Return (Avg. Rate Base * Rate of Return)***		$ 3,573,184	$ 3,322,990	$ 3,095,260	$ 2,884,273
31						
32	***Cost of Service:***					
33	Operation & Maintenance Expenses		$ 7,667,114	$ 7,338,512	$ 7,063,168	$ 6,829,410
34	Administrative & General		1,579,513	1,619,001	1,659,476	1,700,963
35	Depreciation Expense		302,209	304,053	305,898	307,743
36	Depreciation Common Expense		134,804	154,148	176,268	201,562
37	Depletion Expense		3,925,684	3,604,985	3,326,255	3,082,369
38	Property & Other Taxes		822,056	790,882	765,102	743,546
39	MPSC & MCC Revenue Tax	0.49%	80,388	76,820	73,861	71,316
40	Misc. Revenues		(264,000)	(264,000)	(264,000)	(264,000)
41	Oil and Liquid Sales		(126,545)	(115,887)	(106,613)	(98,407)
42	Gathering Revenues		(910,141)	(833,486)	(766,780)	(707,762)
43	Deferred Income Taxes		(24,442)	(33,140)	(43,501)	(49,094)
44	Current Income Taxes		1,390,028	1,309,910	1,258,607	1,208,565
45	***Total Cost of Service***		$ 14,576,668	$ 13,951,799	$ 13,447,741	$ 13,026,210
46						
47	***Less Variable Costs:***					
48	Production Taxes		$ 473,577	$ 433,691	$ 398,981	$ 368,272
49	Royalty Expense		1,270,494	1,163,488	1,070,371	987,986
50	***Total Variable Cost of Service***		$ 1,744,071	$ 1,597,179	$ 1,469,353	$ 1,356,259
51						
52	**Total Fixed Revenue Requirement (Ln 30 + Ln 45 - Ln 50)**		$ 16,405,781	$ 15,677,609	$ 15,073,648	$ 14,554,224
53						
54	**Test Period Normalized Load (Dkt)**		19,261,583	19,417,978	19,575,783	19,735,012
55	**Fixed Cost Unit Rate Per Year**		$ 0.8517	$ 0.8074	$ 0.7700	$ 0.7375

	A	B	C	D	E	F
1	**NorthWestern Energy**					
2	**South Bear Paw (Devon) Natural Gas Properties**					
3	**Docket No. D2016.9.68**					
4						
5	**Forecasted - Revenue Requirement**					
6			2016	2017	2018	2019
56						
57						
58						
59	***Income Tax Computation:***					
60	Revenues		$ 16,405,781	$ 15,677,609	$ 15,073,648	$ 14,554,224
61	Operating Expenses		6,396,620	6,175,023	5,992,796	5,841,423
62	Administrative & General		1,579,513	1,619,001	1,659,476	1,700,963
63	Miscellaneous Revenues		(264,000)	(264,000)	(264,000)	(264,000)
64	Oil and Liquid Sales		(126,545)	(115,887)	(106,613)	(98,407)
65	Gathering Revenues		(910,141)	(833,486)	(766,780)	(707,762)
66	Property & Other Taxes		348,479	357,191	366,121	375,274
67	MPSC & MCC Revenue Tax		80,388	76,820	73,861	71,316
68	Tax Depreciation/Depletion		4,158,059	3,814,353	3,507,863	3,249,843
69	Tax Depreciation Common		400,489	394,074	364,017	337,389
70	Montana Corporate Income Tax		238,215	224,485	215,693	207,117
71	Interest Expense (Based on Avg. Rate Base)	2.49%	1,213,810	1,128,819	1,051,459	979,787
72	Federal Taxable Income		$ 3,290,895	$ 3,101,216	$ 2,979,755	$ 2,861,282
73						
74	Federal Income Tax @ 35%	35.00%	$ 1,151,813	$ 1,085,426	$ 1,042,914	$ 1,001,449
75						
76	Federal Current Tax Expense		$ 1,151,813	$ 1,085,426	$ 1,042,914	$ 1,001,449
77						
78	Federal Taxable Income		$ 3,290,895	$ 3,101,216	$ 2,979,755	$ 2,861,282
79	Montana Corporate Income Tax		238,215	224,485	215,693	207,117
80	Montana Corporate Taxable		$ 3,529,110	$ 3,325,701	$ 3,195,447	$ 3,068,399
81						
82	Montana Corporate Income Tax @ 6.75%	6.75%	$ 238,215	$ 224,485	$ 215,693	$ 207,117
83						
84	Montana Current Tax Expense		$ 238,215	$ 224,485	$ 215,693	$ 207,117
85						
86	Total Current Income Tax Expense		$ 1,390,028	$ 1,309,910	$ 1,258,607	$ 1,208,565
87						
88	***Deferred Income Tax Computation:***					
89	***Accelerated Tax Depreciation***					
90	Tax Depreciation		4,158,059	3,814,353	3,507,863	3,249,843
91	Less Book Depreciation/Depletion		4,227,892	3,909,038	3,632,153	3,390,111
92	Net Deferred Taxable Income		$ (69,834)	$ (94,686)	$ (124,290)	$ (140,269)
93	Federal Income Tax Rate		35%	35%	35%	35%
94	Federal Deferred Income Tax Expense-Accelerated Tx Deprec		$ (24,442)	$ (33,140)	$ (43,501)	$ (49,094)

	A	B	C	D	E	F	G	H
1	**South Bear Paw (Devon)**							
2	**Forecasted Depreciation**							
3	**2016-2019**							
4				**50%**	**50%**	**40%**	**30%**	
5	**Tax Class**	**Additions**		**2016**	**2017**	**2018**	**2019**	**Total**
6								
7	***DEPLETION G325.2, G330, G331***	-		3,925,684	3,604,985	3,326,255	3,082,369	13,939,292
8								
9	***MACRS 15 G327, G328, G332, G333, G334.1, G334.2***							
10	2016	41,413		21,742	1,967	1,770	1,594	27,074
11	2017	41,413			21,742	1,967	1,770	25,479
12	2018	41,413				17,808	2,361	20,168
13	2019	41,413					13,873	13,873
14								
15	***MACRS 5 G392.7***							-
16	2016	239		144	38	23	14	219
17	2017	239			144	38	23	205
18	2018	239				125	46	170
19	2019	239					105	105
20								
21	***MACRS 7 G396, G397.2***							
22	2016	1,265		723	155	111	79	1,067
23	2017	1,265			723	155	111	988
24	2018	1,265				614	186	800
25	2019	1,265					506	506
26								
27	***MACRS 3 G303.5***							-
28	2016	1,336		891	297	99	50	1,336
29	2017	1,336			891	297	99	1,287
30	2018	1,336				802	356	1,158
31	2019	1,336					713	713
32								
33	***MACRS 39 G390***							-
34	2016	9,605		134	246	246	246	872
35	2017	9,605			134	246	246	626
36	2018	9,605				134	246	380
37	2019	9,605					134	134
38								
39	**2015 AND EARLIER VINTAGES FROM PTAX (Excl Depletion Expense)**	-		208,742	183,032	157,174	144,716	693,663
40	**TOTAL**	**215,435**		**4,158,059**	**3,814,353**	**3,507,863**	**3,249,843**	**14,730,117**

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1															
2	Roll Forward Schedule														
3	MTU - MTU-Northwestern Energy														
4															
5	2016 Gas Rate Case														
6	Federal														
7							Rpt # 30		[redacted] 2016		7/28/2016 14:10				
8															
9															
10								Grouped By:		Location Rollup					
11	Tax Class Rollup					Balance	Additions		Dispositions			Transfers		Balance	Memo
12						Begin of Period								End of Period	
13															
14	South Bear Paw														
15															
16	Total Cost: Book					$61,820,358.51	$0.00		$0.00			$0.00		$61,820,358.51	$0.00
17	Book Tax Differences														
18	AFUDC Debt					($2,114.92)	$0.00		$0.00			$0.00		($2,114.92)	$0.00
19	AFUDC Equity					($3,463.08)	$0.00		$0.00			$0.00		($3,463.08)	$0.00
20	Bonus Depr Reduction					($1,689,816.49)	$0.00		$0.00			$0.00		($1,689,816.49)	$0.00
21	Capitalized Interest					$7,171.06	$0.00		$0.00			$0.00		$7,171.06	$0.00
22	Manual Tax Repair Expense					($0.01)	$0.00		$0.00			$0.00		($0.01)	$0.00
23	Tax Repair Expense					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
24	Taxable CIAC					$0.01	$0.00		$0.00			$0.00		$0.01	$0.00
25															
26	Total Book Tax Differences					($1,688,223.43)	$0.00		$0.00			$0.00		($1,688,223.43)	$0.00
27	Ordinary Retirements					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
28															
29	Memo					$0.01	$0.00		$0.00			$0.00		$0.01	$0.00
30	Tax Balance					$60,132,135.09	$0.00		$0.00			$0.00		$60,132,135.09	$0.00
31															
32	Tax Reserve					$12,937,019.76	$208,742.31		$0.00			$0.00		$13,145,762.07	$0.00
33	Net Value:					$47,195,115.33	###########		$0.00			$0.00		$46,986,373.02	$0.00
34	Roll Forward Schedule														
35	MTU - MTU-Northwestern Energy														
36															
37	2016 Gas Rate Case														
38	Federal														
39							Rpt # 30		[redacted] 2017		7/28/2016 14:10				
40															
41															
42								Grouped By:		Location Rollup					
43	Tax Class Rollup					Balance	Additions		Dispositions			Transfers		Balance	Memo
44						Begin of Period								End of Period	
45															
46	South Bear Paw														
47															
48	Total Cost: Book					$61,820,358.51	$0.00		$0.00			$0.00		$61,820,358.51	$0.00
49	Book Tax Differences														
50	AFUDC Debt					($2,114.92)	$0.00		$0.00			$0.00		($2,114.92)	$0.00
51	AFUDC Equity					($3,463.08)	$0.00		$0.00			$0.00		($3,463.08)	$0.00
52	Bonus Depr Reduction					($1,689,816.49)	$0.00		$0.00			$0.00		($1,689,816.49)	$0.00
53	Capitalized Interest					$7,171.06	$0.00		$0.00			$0.00		$7,171.06	$0.00
54	Manual Tax Repair Expense					($0.01)	$0.00		$0.00			$0.00		($0.01)	$0.00
55	Tax Repair Expense					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
56	Taxable CIAC					$0.01	$0.00		$0.00			$0.00		$0.01	$0.00
57															
58	Total Book Tax Differences					($1,688,223.43)	$0.00		$0.00			$0.00		($1,688,223.43)	$0.00
59	Ordinary Retirements					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
60															
61	Memo					$0.01	$0.00		$0.00			$0.00		$0.01	$0.00
62	Tax Balance					$60,132,135.09	$0.00		$0.00			$0.00		$60,132,135.09	$0.00
63															
64	Tax Reserve					$13,145,762.07	$183,031.68		$0.00			$0.00		$13,328,793.75	$0.00
65	Net Value:					$46,986,373.02	###########		$0.00			$0.00		$46,803,341.34	$0.00
66	Roll Forward Schedule														
67															
68	2016 Gas Rate Case														
69	Federal														
70							Rpt # 30		[redacted] 2018		7/28/2016 14:10				
71															
72															
73								Grouped By:		Location Rollup					
74	Tax Class Rollup					Balance	Additions		Dispositions			Transfers		Balance	Memo
75						Begin of Period								End of Period	
76															
77	South Bear Paw														

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
78															
79	Total Cost: Book					$61,820,358.51	$0.00		$0.00			$0.00		$61,820,358.51	$0.00
80	Book Tax Differences														
81	AFUDC Debt					($2,114.92)	$0.00		$0.00			$0.00		($2,114.92)	$0.00
82	AFUDC Equity					($3,463.08)	$0.00		$0.00			$0.00		($3,463.08)	$0.00
83	Bonus Depr Reduction					($1,689,816.49)	$0.00		$0.00			$0.00		($1,689,816.49)	$0.00
84	Capitalized Interest					$7,171.06	$0.00		$0.00			$0.00		$7,171.06	$0.00
85	Manual Tax Repair Expense					($0.01)	$0.00		$0.00			$0.00		($0.01)	$0.00
86	Tax Repair Expense					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
87	Taxable CIAC					$0.01	$0.00		$0.00			$0.00		$0.01	$0.00
88															
89	Total Book Tax Differences					($1,688,223.43)	$0.00		$0.00			$0.00		($1,688,223.43)	$0.00
90	Ordinary Retirements					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
91															
92	Memo					$0.01	$0.00		$0.00			$0.00		$0.01	$0.00
93	Tax Balance					$60,132,135.09	$0.00		$0.00			$0.00		$60,132,135.09	$0.00
94															
95	Tax Reserve					$13,328,793.75	$157,173.70		$0.00			$0.00		$13,485,967.45	$0.00
96	Net Value:					$46,803,341.34	###########		$0.00			$0.00		$46,646,167.64	$0.00
97	Roll Forward Schedule														
98															
99	2016 Gas Rate Case														
100	Federal														
101							Rpt # 30		2019		7/28/2016 14:10				
102															
103															
104								Grouped By:		Location Rollup					
105	Tax Class Rollup					Balance	Additions		Dispositions			Transfers		Balance	Memo
106						Begin of Period								End of Period	
107															
108	South Bear Paw														
109															
110	Total Cost: Book					$61,820,358.51	$0.00		$0.00			$0.00		$61,820,358.51	$0.00
111	Book Tax Differences														
112	AFUDC Debt					($2,114.92)	$0.00		$0.00			$0.00		($2,114.92)	$0.00
113	AFUDC Equity					($3,463.08)	$0.00		$0.00			$0.00		($3,463.08)	$0.00
114	Bonus Depr Reduction					($1,689,816.49)	$0.00		$0.00			$0.00		($1,689,816.49)	$0.00
115	Capitalized Interest					$7,171.06	$0.00		$0.00			$0.00		$7,171.06	$0.00
116	Manual Tax Repair Expense					($0.01)	$0.00		$0.00			$0.00		($0.01)	$0.00
117	Tax Repair Expense					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
118	Taxable CIAC					$0.01	$0.00		$0.00			$0.00		$0.01	$0.00
119															
120	Total Book Tax Differences					($1,688,223.43)	$0.00		$0.00			$0.00		($1,688,223.43)	$0.00
121	Ordinary Retirements					$0.00	$0.00		$0.00			$0.00		$0.00	$0.00
122															
123	Memo					$0.01	$0.00		$0.00			$0.00		$0.01	$0.00
124	Tax Balance					$60,132,135.09	$0.00		$0.00			$0.00		$60,132,135.09	$0.00
125															
126	Tax Reserve					$13,485,967.45	$144,715.73		$0.00			$0.00		$13,630,683.18	$0.00
127	Net Value:					$46,646,167.64	###########		$0.00			$0.00		$46,501,451.91	$0.00
128	Roll Forward Schedule														

	A	B	C	D	E	F	G
1				NorthWestern Energy			
2				South Bear Paw (Devon)			
3							
4				Capital Structure			
5							
6							
7							
8							
9				Percent	Rate of		
10		Capital Structure	Rate	Capitalization	Return		
11		Equity	10.35%	46.79%	4.84%		
12		Debt	4.67%	53.21%	2.49%		
13							
14		Total		100.00%	7.33%		

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1			NorthWestern Energy														
2			South Bear Paw (Devon)									Forecast					
3						Sales &						Escalation					
4			Projected Costs			Admin.			Allocation of			Rate					
5						& General	Labor		Gas Production	One-Time		2.50%					
6				2015 Actuals		Adjustment	Adjustment	Property Tax	Administration	Adjustments		Test Period		2016	2017	2018	2019
7		OPERATIONS & MAINTENANCE:															
8			Production Expenses														
9																	
10		Production & Gathering-Operation															
11		750	Supervision & Engineering	20,366			574		87,857			108,796		111,516	114,303	117,161	120,090
12		751	Maps & Records	-			-		-			-		-	-	-	-
13		752	Gas Wells Expenses	734,300			25,096		500,400	(61,836)		1,197,961		1,227,910	1,258,607	1,290,073	1,322,324
14		753	Field Lines Expenses	2,905			29		-			2,934		3,007	3,082	3,159	3,238
15		754	Field Compressor Station Expense	3,886,416			2,735		-			3,889,151		3,655,511	3,365,387	3,112,919	2,889,549
16		755	Field Comp. Station Fuel & Power	91,836			-		-			91,836		94,132	96,485	98,897	101,370
17		756	Field Meas. & Reg. Station Expense	87,671			2,401		-			90,072		92,324	94,632	96,998	99,423
18		757	Dehydration Expense	2,514			14		-			2,529		2,592	2,657	2,723	2,791
19		758	Gas Well Royalties	1,356,666			-		-			1,356,666		1,270,494	1,163,488	1,070,371	987,988
20		759	Other Expenses	994,131			10,374		1,567	(143,835)		862,236		883,814	905,909	928,557	951,771
21		760	Rents	93,967			-		-			93,967		96,316	98,724	101,192	103,722
22		Total Oper. Production & Gathering		7,270,773		-	41,223	-	589,844	(205,671)		7,696,169		7,437,815	7,103,278	6,822,051	6,562,285
23		Production & Gathering-Maintenance															
24		761	Supervision and Engineering	-			-		-			-		-	-	-	-
25		762	Structures and Improvements	-			-		-			-		-	-	-	-
26		763	Producing Gas Wells	41,103			28		-			41,131		42,159	43,213	44,293	45,401
27		764	Field Lines	124,996			2,927		-	(17,485)		110,438		113,199	116,029	118,930	121,903
28		765	Field Compressor Station Equipment	31,300			324		-			31,624		32,415	33,225	34,056	34,907
29		766	Field Measuring and Regulating Station Equipment	6,693			1		-			6,694		6,861	7,033	7,209	7,389
30		767	Purification Equipment	10,887			42		-			10,930		11,203	11,483	11,770	12,064
31		768	Drilling and Cleaning Equipment	-			-		-			-		-	-	-	-
32		769	Other Equipment	(4,340)			-		-			(4,340)		(4,448)	(4,559)	(4,673)	(4,790)
33		Total Maint. Production & Gathering		210,639		-	3,322	-	-	(17,485)		196,477		201,389	206,423	211,584	216,874
34		Total Production & Gathering Expenses		7,481,412		-	44,545	-	589,844	(223,156)		7,892,646		7,639,004	7,309,699	7,033,635	6,799,139
35		Distribution Operation															
36		870	Supervision & Engineering						-			-		-	-	-	-
37		874	Mains and Services						-			-		-	-	-	-
38		875	Meas. & Reg. Station-General						-			-		-	-	-	-
39		877	Meas. & Reg. Station-City Gate						-			-		-	-	-	-
40		878	Meter & House Regulator						-			-		-	-	-	-
41		879	Customer Installations						205			205		210	215	220	226
42		880	Other Expenses						27,220			27,220		27,900	28,598	29,312	30,045
43		881	Rents						-			-		-	-	-	-
44		Total Operation-Distribution		-		-	-	-	27,424	-		27,424		28,110	28,812	29,533	30,271
45			TOTAL OPER. & MAINT. EXPENSES	7,481,412		-	44,545	-	617,268	(223,156)		7,920,070		7,667,114	7,338,512	7,063,168	6,829,410
46																	
47		Customer Accounts-Operation															
48		902	Meter Reading						-			-		-	-	-	-
49		903	Customer Records & Collection						97,836			97,836		100,282	102,789	105,359	107,993
50		904	Uncollectible Accounts						17,110			17,110		17,538	17,976	18,426	18,887
51		905	Miscellaneous Customer Accounts						43			43		44	45	46	47
52		Total Customer Accounts Expenses		-		-	-	-	114,989	-		114,989		117,864	120,810	123,831	126,926
53																	
54		Customer Service-Operation															
55		908	Customer Assistance						91,730			91,730		94,024	96,374	98,784	101,253
56		909	Inform. & Instructional Advertising						23,736			23,736		24,329	24,937	25,561	26,200
57		Total Customer Service & Information Exp.		-		-	-	-	115,466	-		115,466		118,353	121,312	124,345	127,453
58																	
59		Admin. & General - Operation															
60		920	Administrative & General Salaries						730,970			730,970		749,245	767,976	787,175	806,854
61		921	Office Supplies & Expenses						181,254			181,254		185,785	190,430	195,190	200,070
62		922	Administrative Exp. Transferred-Cr.						(91,986)			(91,986)		(94,285)	(96,643)	(99,059)	(101,535)
63		923	Outside Services Employed						175,828			175,828		180,223	184,729	189,347	194,081
64		924	Property Insurance						563			563		578	592	607	622
65		925	Injuries & Damages			(20,155)			166,902	143,835		290,582		297,847	305,293	312,925	320,748
66		926	Employee Pensions & Benefits						37,011			37,011		37,936	38,885	39,857	40,853
67		928	Regulatory Commission Expenses						4,162			4,162		4,266	4,373	4,482	4,594
68		930	Miscellaneous General Expenses						48,816			48,816		50,036	51,287	52,569	53,884
69		931	Rents						32,700			32,700		33,518	34,356	35,214	36,095
70		Total Operation-Admin. & General		-		(20,155)	-	-	1,266,220	143,835		1,409,900		1,445,148	1,481,277	1,518,309	1,556,266
71		Admin. & General - Maintenance															
72		935	General Plant						58,095			58,095		59,547	61,036	62,562	64,126
73		Total Admin. & General Expenses		-		(20,155)	-	-	1,574,771	143,835		1,698,451		1,740,912	1,784,435	1,829,046	1,874,772
74																	
75																	
76		408.1	Payroll Taxes	91,682			3,118		7,364			102,163		104,717	107,335	110,019	112,769
77			Vehicle Taxes	9,472								9,472		9,709	9,952	10,201	10,456
78			Property Taxes	193,856				19,227				213,084		213,084	218,411	223,871	229,468
79			Production Taxes	505,898								505,898		473,577	433,691	398,981	368,272
80			MPSC/MCC Taxes	47,020								47,020		80,388	76,820	73,861	71,316
81			Other Taxes	20,458								20,458		20,969	21,493	22,031	22,581
82																	
83		457110	Non-operating	-								-		-	-	-	-
84		469610	Miscellaneous Revenues	401,529								401,529		264,000	264,000	264,000	264,000
85		459100	Gathering Revenues	971,873								971,873		918,141	833,488	766,769	707,782
86		492200	Liquid Sales	135,129								135,129		126,545	115,887	106,613	98,407
87				1,508,530		-	-	-	-	-		1,508,530		1,308,687	1,213,373	1,137,392	1,070,189
88																	
89			Depreciation & Amortization						147,853			147,853		147,853	147,853	147,853	147,853
90																	
91			Pension Differential						(157,463)			(157,463)		(161,399)	(165,434)	(169,570)	(173,809)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y
1	NORTHWESTERN ENERGY - MONTANA NATURAL GAS UTILITY																								
2	CALCULATION OF CASH WORKING CAPITAL DOCKET NO. D2016.9.68																								
3																									
4			Forecast Year 2016						Forecast Year 2017						Forecast Year 2018						Forecast Year 2019				
5																									
6			12 Month Ended		Net Lag		Cash		12 Month Ended		Net Lag		Cash		12 Month Ended		Net Lag		Cash		12 Month Ended		Net Lag		Cash
7			Expenses		Days [1]		Working Capital		Expenses		Days [1]		Working Capital		Expenses		Days [1]		Working Capital		Expenses		Days [1]		Working Capital
8																									
9																									
10	Operation, Maintenance and Admin. Costs		7,976,133						7,794,024						7,652,272						7,542,386				
11	Other Taxes		428,868						434,011						439,982						446,590				
12	State Income Taxes		238,215						224,485						215,693						207,117				
13	Federal Income Taes		1,151,813						1,085,426						1,042,914						1,001,449				
14	Sub-Total		9,795,029		-65.21		-1,749,956		9,537,946		-65.21		-1,704,026		9,350,861		-65.21		-1,670,602		9,197,541		-65.21		-1,643,210
15																									
16																									
17	Rate Base Without Cash Working Capital		50,664,676						47,193,987						44,043,342						41,127,912				
18																									
19	Weighted Cost of Debt [2]		2.49%						2.49%						2.49%						2.49%				
20																									
21	Interest Expense in Return		1,261,550		-48.41		-167,320		1,175,130		-48.41		-155,858		1,096,679		-48.41		-145,453		1,024,085		-48.41		-135,825
22																									
23	Total Cash Working Capital						-1,917,275						-1,859,884						-1,816,054						-1,779,035
24																									
25																									
26	[1]Net Lag Days from MAC 2016 Lead/Lag Study Update																								
27																									
28	[2]Weighted Cost of Debt Proposed in D2016.9.68																								

	A	B	C	D	E	F	G	H	I	J
1										
2			Estimated net gas production MMCF							
3										
4		Year	Battle Creek	Bear Paw	South Bear Paw	Wilbanks	Black Hills			
5										
6		2015	350	1008	4286	12	93			
7		2016	320	862	4014	11	112			
8		2017	293	768	3676	10	100			
9		2018	268	680	3382	9	90			
10		2019	245	608	3122	8	82			
11										
12										
13		Year	Battle Creek	decline		Bear Paw	decline		South Bear Paw	decline
14										
15		2015	350			1101			4298	
16		2016	320	8.6%		974	11.5%		4025	6.4%
17		2017	293	8.4%		868	10.9%		3686	8.4%
18		2018	268	8.5%		770	11.3%		3391	8.0%
19		2019	245	8.6%		690	10.4%		3130	7.7%
20										
21										
22		The production in each area will decline and so will the Compression by others in Acct. 754								
23										
24				Normalized						
25		***Battle Creek***	***A/C 754***	Expense						
26		Year 2015	$ 19,052.05							
27		Normalized Adj:								
28		2016	$ (1,633.03)	$ 17,419.02						
29		2017	$ (1,469.73)	$ 15,949.29						
30		2018	$ (1,360.86)	$ 14,588.43						
31		2019	$ (1,251.99)	$ 13,336.44						
32										
33										
34			A/C 754	[1]Compression	Compression			A/C 754	[1]Compression	Compression
35		***Bear Paw (NFR)***	Total	by Others	Operations		***South Bear Paw (Devon)***	Total	by Others	Operations
36		Year 2015	$ 1,200,552.38	$ 857,702.62	$ 342,849.76		Year 2015	$ 3,889,150.99	$ 3,678,329.00	$ 210,821.99
37										
38		*2016 Willow Creek Adj.*	$ (89,856.00)		$ (89,856.00)					
39			$ 1,110,696.38	$ 857,702.62	$ 252,993.76			$ 3,889,150.99	$ 3,678,329.00	$ 210,821.99
40		Production Reduction					Production Reduction			
41		Adjustment					Adjustment			
42		2016	$ (98,935.72)	$ (98,935.72)			2016	$ (233,639.79)	$ (233,639.79)	
43										
44		Test Year 2016	$ 1,011,760.66	$ 758,766.90	$ 252,993.76		Test Year 2016	$ 3,655,511.20	$ 3,444,689.21	$ 210,821.99
45										
46		*2017 Willow Creek Adj.*	$ (89,856.00)		$ (89,856.00)					
47			$ 921,904.66	$ 758,766.90	$ 163,137.76			$ 3,655,511.20	$ 3,444,689.21	$ 210,821.99
48		Production Reduction					Production Reduction			
49		Adjustment					Adjustment			
50		2017	$ (82,576.27)	$ (82,576.27)			2017	$ (290,124.13)	$ (290,124.13)	
51										
52		Test Year 2017	$ 839,328.38	$ 676,190.62	$ 163,137.76		Test Year 2017	$ 3,365,387.07	$ 3,154,565.08	$ 210,821.99
53										
54		Production Reduction					Production Reduction			
55		Adjustment					Adjustment			
56		2018	$ (76,344.10)	$ (76,344.10)			2018	$ (252,467.90)	$ (252,467.90)	
57										
58		Test Year 2018	$ 762,984.28	$ 599,846.52	$ 163,137.76		Test Year 2018	$ 3,112,919.16	$ 2,902,097.17	$ 210,821.99
59										
60		Production Reduction					Production Reduction			
61		Adjustment					Adjustment			
62		2019	$ (62,321.72)	$ (62,321.72)			2019	$ (223,369.91)	$ (223,369.91)	
63										
64		Test Year 2019	$ 700,662.56	$ 537,524.80	$ 163,137.76		Test Year 2019	$ 2,889,549.26	$ 2,678,727.26	$ 210,821.99
65										
66										
67		[1]Compression by other in Order No. 01BPF754COTH.					[1]Compression by other in Order No. 01BPF754COTH.			

	A	B	C	D	E	F	G	H	I	J	K	L
1	NORTHWESTERN ENERGY - MONTANA GAS OPERATIONS - BEAR PAW RATE BASE											
2												
3				AVE.			AVE.		DEFERRED INCOME TAXES			AVE.
4			PLANT BALANCE	PLANT BALANCE		DEPR RESERVE	DEPR RESERVE		NET ACTIVITY	ENDING BALANCE		DEFERRED TAX
5												
6	DECEMBER	2014	$ 61,687,778			$ 5,260,106				$ 1,690,401		
7												
8	JANUARY	2015	$ 61,704,620			$ 5,658,691			$ 2,764	$ 1,693,165		
9												
10	FEBRUARY	2015	$ 61,740,174			$ 6,037,059			$ 2,764	$ 1,695,929		
11												
12	MARCH	2015	$ 61,760,210			$ 6,380,547			$ 2,764	$ 1,698,693		
13												
14	APRIL	2015	$ 61,760,210			$ 6,765,413			$ 2,764	$ 1,701,457		
15												
16	MAY	2015	$ 61,760,210			$ 7,129,832			$ 2,764	$ 1,704,222		
17												
18	JUNE	2015	$ 61,755,700			$ 7,498,603			$ 2,764	$ 1,706,986		
19												
20	JULY	2015	$ 61,755,700			$ 7,870,256			$ 2,764	$ 1,709,750		
21												
22	AUGUST	2015	$ 61,755,700			$ 8,245,123			$ 2,764	$ 1,712,514		
23												
24	SEPTEMBER	2015	$ 61,751,830			$ 8,613,553			$ 2,764	$ 1,715,278		
25												
26	OCTOBER	2015	$ 61,789,396			$ 8,980,407			$ 2,764	$ 1,718,043		
27												
28	NOVEMBER	2015	$ 61,789,486			$ 9,343,808			$ 2,764	$ 1,720,807		
29												
30	DECEMBER	2015	$ 61,820,359	61,756,259		$ 9,702,348	7,498,904		$ 2,764	$ 1,723,571		1,706,986
31												
32	JANUARY	2016	$ 61,834,884			$ 10,042,351			$ (2,037)	$ 1,721,534		
33												
34	FEBRUARY	2016	$ 61,849,409			$ 10,382,354			$ (2,037)	$ 1,719,497		
35												
36	MARCH	2016	$ 61,863,935			$ 10,722,357			$ (2,037)	$ 1,717,461		
37												
38	APRIL	2016	$ 61,878,460			$ 11,062,361			$ (2,037)	$ 1,715,424		
39	.											
40	MAY	2016	$ 61,892,986			$ 11,402,364			$ (2,037)	$ 1,713,387		
41												
42	JUNE	2016	$ 61,907,511			$ 11,742,367			$ (2,037)	$ 1,711,350		
43												
44	JULY	2016	$ 61,922,037			$ 12,082,370			$ (2,037)	$ 1,709,313		
45												
46	AUGUST	2016	$ 61,936,562			$ 12,422,374			$ (2,037)	$ 1,707,276		
47												
48	SEPTEMBER	2016	$ 61,951,088			$ 12,762,377			$ (2,037)	$ 1,705,240		
49												
50	OCTOBER	2016	$ 61,965,613			$ 13,102,380			$ (2,037)	$ 1,703,203		
51												
52	NOVEMBER	2016	$ 61,980,138			$ 13,442,383			$ (2,037)	$ 1,701,166		
53												
54	DECEMBER	2016	$ 61,994,664	61,907,511		$ 13,782,387	11,742,367		$ (2,037)	$ 1,699,129		1,711,350
55												
56	JANUARY	2017	$ 62,009,011			$ 14,095,819			$ (2,762)	$ 1,696,368		
57												
58	FEBRUARY	2017	$ 62,023,359			$ 14,409,251			$ (2,762)	$ 1,693,606		
59												
60	MARCH	2017	$ 62,037,706			$ 14,722,683			$ (2,762)	$ 1,690,844		
61												
62	APRIL	2017	$ 62,052,053			$ 15,036,115			$ (2,762)	$ 1,688,083		
63												
64	MAY	2017	$ 62,066,401			$ 15,349,547			$ (2,762)	$ 1,685,321		
65												
66	JUNE	2017	$ 62,080,748			$ 15,662,979			$ (2,762)	$ 1,682,559		
67												
68	JULY	2017	$ 62,095,095			$ 15,976,411			$ (2,762)	$ 1,679,798		
69												
70	AUGUST	2017	$ 62,109,443			$ 16,289,843			$ (2,762)	$ 1,677,036		
71												
72	SEPTEMBER	2017	$ 62,123,790			$ 16,603,275			$ (2,762)	$ 1,674,274		
73												
74	OCTOBER	2017	$ 62,138,138			$ 16,916,707			$ (2,762)	$ 1,671,513		
75												
76	NOVEMBER	2017	$ 62,152,485			$ 17,230,139			$ (2,762)	$ 1,668,751		
77												
78	DECEMBER	2017	$ 62,166,832	62,080,748		$ 17,543,571	15,662,979		$ (2,762)	$ 1,665,989		1,682,559
79												
80	JANUARY	2018	$ 62,183,465			$ 17,833,930			$ (3,625)	$ 1,662,364		
81												
82	FEBRUARY	2018	$ 62,200,098			$ 18,124,288			$ (3,625)	$ 1,658,739		
83												
84	MARCH	2018	$ 62,216,731			$ 18,414,646			$ (3,625)	$ 1,655,114		
85												
86	APRIL	2018	$ 62,233,364			$ 18,705,005			$ (3,625)	$ 1,651,489		
87												
88	MAY	2018	$ 62,249,996			$ 18,995,363			$ (3,625)	$ 1,647,864		
89												

	A	B	C	D	E	F	G	H	I	J	K	L
1	NORTHWESTERN ENERGY - MONTANA GAS OPERATIONS - BEAR PAW RATE BASE											
2												
3				AVE.			AVE.		DEFERRED INCOME TAXES			AVE.
4			PLANT BALANCE	PLANT BALANCE		DEPR RESERVE	DEPR RESERVE		NET ACTIVITY	ENDING BALANCE		DEFERRED TAX
90	JUNE	2018	$ 62,266,629			$ 19,285,721			$ (3,625)	$ 1,644,239		
91												
92	JULY	2018	$ 62,283,262			$ 19,576,080			$ (3,625)	$ 1,640,613		
93												
94	AUGUST	2018	$ 62,299,895			$ 19,866,438			$ (3,625)	$ 1,636,988		
95												
96	SEPTEMBER	2018	$ 62,316,528			$ 20,156,796			$ (3,625)	$ 1,633,363		
97												
98	OCTOBER	2018	$ 62,333,161			$ 20,447,154			$ (3,625)	$ 1,629,738		
99												
100	NOVEMBER	2018	$ 62,349,793			$ 20,737,513			$ (3,625)	$ 1,626,113		
101												
102	DECEMBER	2018	$ 62,366,426	62,266,629		$ 21,027,871	19,285,721		$ (3,625)	$ 1,622,488		1,644,239
103												
104	JANUARY	2019	$ 62,375,403			$ 21,298,059			$ (4,091)	$ 1,618,397		
105												
106	FEBRUARY	2019	$ 62,384,379			$ 21,568,247			$ (4,091)	$ 1,614,305		
107												
108	MARCH	2019	$ 62,393,356			$ 21,838,435			$ (4,091)	$ 1,610,214		
109												
110	APRIL	2019	$ 62,402,332			$ 22,108,624			$ (4,091)	$ 1,606,123		
111												
112	MAY	2019	$ 62,411,309			$ 22,378,812			$ (4,091)	$ 1,602,032		
113												
114	JUNE	2019	$ 62,420,285			$ 22,649,000			$ (4,091)	$ 1,597,941		
115												
116	JULY	2019	$ 62,429,261			$ 22,919,188			$ (4,091)	$ 1,593,850		
117												
118	AUGUST	2019	$ 62,438,238			$ 23,189,376			$ (4,091)	$ 1,589,758		
119												
120	SEPTEMBER	2019	$ 62,447,214			$ 23,459,564			$ (4,091)	$ 1,585,667		
121												
122	OCTOBER	2019	$ 62,456,191			$ 23,729,753			$ (4,091)	$ 1,581,576		
123												
124	NOVEMBER	2019	$ 62,465,167			$ 23,999,941			$ (4,091)	$ 1,577,485		
125												
126	DECEMBER	2019	$ 62,474,144	62,420,285		$ 24,270,129	22,649,000		$ (4,091)	$ 1,573,394		1,597,941

	A	B	C	D	E	F	G	H
1		NORTHWESTERN ENERGY						
2		NATURAL GAS TRANSMISSION, DISTRIBUTION & STORAGE UTILITY						
3		INCOME STATEMENT						
4		ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED						
5					NATURAL GAS	REVENUE	SALES &	
6					TRANSMISSION,	& REVENUE	ADMINISTRATIVE	
7			NATURAL GAS	SUPPLY	DISTRIBUTION &	RELATED	& GENERAL	LABOR
8			UTILITY	FUNCTION	STORAGE UTILITY	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT
9		REVENUES:						
10		RATE SCHEDULE REVENUES	$150,261,562	($60,916,108)	$89,345,454	$3,390,085		
11		SALES FOR RESALE	1,162,945	(836,575)	326,370	3,726		
12		PROVISION FOR RATE REFUNDS	(890,160)	890,160	(0)	0		
13		TRANSPORTATION	23,586,269	(1,616,260)	21,970,009	(375,092)		
14		MISCELLANEOUS REVENUES	2,289,464	(1,139,640)	1,149,824	(536,304)		
15		GROSS REVENUES (LINE 10 THRU 14)	$176,410,080	($63,618,423)	$112,791,657	$2,482,415	$0	$0
16								
17		COST OF SERVICE:						
18		PRODUCTION & GATHERING OPERATION	$10,383,709	($10,383,709)	$0			0
19		PRODUCTION & GATHERING MAINTENANCE	514,660	(514,660)	0			0
20		GAS SUPPLY	35,068,658	(34,592,753)	475,905			28,050
21		STORAGE OPERATION	1,040,696	-	1,040,696			14,588
22		STORAGE MAINTENANCE	354,669	-	354,669			4,753
23		TRANSMISSION OPERATION	7,608,824	-	7,608,824			157,764
24		TRANSMISSION MAINTENANCE	2,293,797	-	2,293,797			63,101
25		DISTRIBUTION OPERATION	11,080,587	(56,914)	11,023,673			(13,396)
26		DISTRIBUTION MAINTENANCE	3,468,704	-	3,468,704			40,026
27		CUSTOMER ACCOUNTS EXPENSE	3,468,625	(242,803)	3,225,822	150,410	(20,260)	34,813
28		CUSTOMER SERVICE AND INFORMATION EXPENSE	1,721,161	(236,150)	1,485,011		0	39,112
29		SALES EXPENSE	151,001	(34,713)	116,288		(116,288)	0
30		ADMINISTRATIVE AND GENERAL EXPENSE	23,350,351	(2,753,240)	20,597,111	(3,327,005)	(323,025)	71,595
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	$100,505,442	-$48,814,942	$51,690,500	-$3,176,595	-$459,573	$440,406
32								
33		DEPRECIATION	$15,396,572	-$529,375	$14,867,197			
34		AMORTIZATION OF NATURAL GAS PLANT	7,699,240	(6,448,434)	1,250,806			
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN	(420,516)	-	(420,516)			
36		* AMORTIZATION RE:PROPERTY TAXES	(1,046,934)	-	(1,046,934)			
37		* AMORTIZATION RE:USBC	(1,352,578)	-	(1,352,578)			
38		* AMORTIZATION RE:COMPENSATED ABSENCES	-	-	-			
39		* AMORTIZATION RE:	-	-	-			
40		* AMORTIZATION RE:	-	-	-			
41		* AMORTIZATION RE:NG MPSC/MCC TAXES	173,472	(24,288)	149,184			
42		* PENSION DIFFERENTIAL	(2,411,149)	332,572	(2,078,577)			
43		TAXES OTHER THAN INCOME TAXES	29,666,502	(1,388,688)	28,277,814	233,198		30,902
44		INCOME TAXES - FEDERAL - U.S.	(1,004,923)	1,592,193	587,270	0	0	0
45		INCOME TAXES - OTHER	(200,598)	334,820	134,222	0	0	0
46		DEFERRED INCOME TAXES	3,298,178	(3,232,876)	65,302	2,137,091	181,014	(185,636)
47		SUBTOTAL (LINE 33 THRU 46)	49,797,265	(9,364,076)	40,433,190	$2,370,289	$181,014	($154,734)
48								
49		TOTAL COST OF SERVICE (LINE 31 + 47)	150,302,707	(58,179,017)	92,123,690	($806,306)	($278,559)	$285,672
50								
51		UTILITY OPERATING INCOME (LINE 15 - 49)	26,107,373	(5,439,406)	20,667,967	$3,288,720	$278,559	($285,672)
52								
53		NATURAL GAS UTILITY RATE BASE	$444,875,429	73,577,215	$371,298,214	$0	$0	$0
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)			5.57%			
55								
56		REQUIRED REVENUE INCREASE			$10,856,569	($5,452,529)	($461,836)	$473,629

	A	B	I	J	K	L	M	N	O
1		NORTHWESTERN ENERGY							
2		NATURAL GAS TRANSMISSION, DISTRIBUTION & STORAGE UTILITY							
3		INCOME STATEMENT							
4		ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED							
5									
6				CORPORATE	STIPULATION AND		TAXES - OTHER		WORKING
7			ONE-TIME	ALLOCATION	MARKET CREDITS	AMORTIZATION	THAN INCOME	DEPRECIATION	CAPITAL
8			ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT
9		REVENUES:							
10		RATE SCHEDULE REVENUES							
11		SALES FOR RESALE							
12		PROVISION FOR RATE REFUNDS							
13		TRANSPORTATION							
14		MISCELLANEOUS REVENUES							
15		GROSS REVENUES (LINE 10 THRU 14)	$0	$0	$0	$0	$0	$0	$0
16									
17		COST OF SERVICE:							
18		PRODUCTION & GATHERING OPERATION							
19		PRODUCTION & GATHERING MAINTENANCE							
20		GAS SUPPLY							
21		STORAGE OPERATION							
22		STORAGE MAINTENANCE							
23		TRANSMISSION OPERATION							
24		TRANSMISSION MAINTENANCE							
25		DISTRIBUTION OPERATION		(14,129)					
26		DISTRIBUTION MAINTENANCE							
27		CUSTOMER ACCOUNTS EXPENSE	10,087	(54,097)					
28		CUSTOMER SERVICE AND INFORMATION EXPENSE		(13,939)					
29		SALES EXPENSE		0					
30		ADMINISTRATIVE AND GENERAL EXPENSE		(773,655)					
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	$10,087	-$855,820	$0	$0	$0	$0	$0
32									
33		DEPRECIATION						$250,691	
34		AMORTIZATION OF NATURAL GAS PLANT							
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN							
36		* AMORTIZATION RE:PROPERTY TAXES				1,046,934			
37		* AMORTIZATION RE:USBC				1,352,578			
38		* AMORTIZATION RE:COMPENSATED ABSENCES				0			
39		* AMORTIZATION RE:				0			
40		* AMORTIZATION RE:				0			
41		* AMORTIZATION RE:NG MPSC/MCC TAXES				(40,888)			
42		* PENSION DIFFERENTIAL				(475,643)			
43		TAXES OTHER THAN INCOME TAXES					5,433,565		
44		INCOME TAXES - FEDERAL - U.S.	0	0	0	0	0	0	0
45		INCOME TAXES - OTHER	0	0	0	0	0	0	0
46		DEFERRED INCOME TAXES	(3,973)	337,086	0	(659,043)	(2,140,145)	(87,742)	0
47		SUBTOTAL (LINE 33 THRU 46)	($3,973)	$337,086	$0	$1,223,938	$3,293,420	$162,949	$0
48									
49		TOTAL COST OF SERVICE (LINE 31 + 47)	$6,114	($518,734)	$0	$1,223,938	$3,293,420	$162,949	$0
50									
51		UTILITY OPERATING INCOME (LINE 15 - 49)	($6,114)	$518,734	$0	($1,223,938)	($3,293,420)	($162,949)	$0
52									
53		NATURAL GAS UTILITY RATE BASE	$0	$0	($10,456,297)	$163,570	$0	($129,206)	($2,241,586)
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)							
55									
56		REQUIRED REVENUE INCREASE	$10,137	($860,034)	($1,270,730)	$2,049,106	$5,460,321	$254,458	($272,414)

	A	B	P	Q	R	S	T
1		NORTHWESTERN ENERGY					
2		NATURAL GAS TRANSMISSION, DISTRIBUTION & STORAGE UTILITY					
3		INCOME STATEMENT					
4		ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED					
5							
6				INTEREST	TOTAL	TEST PERIOD	
7			INCOME TAX	SYNCHRONIZATION	UPDATES &	@ PRESENT	
8			ADJUSTMENT	ADJUSTMENT	ADJUSTMENTS	RATES	
9		REVENUES:					
10		RATE SCHEDULE REVENUES			$3,390,085	$92,735,539	
11		SALES FOR RESALE			3,726	330,096	
12		PROVISION FOR RATE REFUNDS			0	0	
13		TRANSPORTATION			(375,092)	21,594,917	
14		MISCELLANEOUS REVENUES			(536,304)	613,520	
15		GROSS REVENUES (LINE 10 THRU 14)	$0	$0	$2,482,415	$115,274,072	
16							
17		COST OF SERVICE:					
18		PRODUCTION & GATHERING OPERATION			$0	$0	
19		PRODUCTION & GATHERING MAINTENANCE			0	0	
20		GAS SUPPLY			28,050	503,955	
21		STORAGE OPERATION			14,588	1,055,284	
22		STORAGE MAINTENANCE			4,753	359,422	
23		TRANSMISSION OPERATION			157,764	7,766,588	
24		TRANSMISSION MAINTENANCE			63,101	2,356,898	
25		DISTRIBUTION OPERATION			(27,525)	10,996,148	
26		DISTRIBUTION MAINTENANCE			40,026	3,508,730	
27		CUSTOMER ACCOUNTS EXPENSE			120,953	3,346,775	
28		CUSTOMER SERVICE AND INFORMATION EXPENSE			25,172	1,510,184	
29		SALES EXPENSE			(116,288)	(0)	
30		ADMINISTRATIVE AND GENERAL EXPENSE			(4,352,090)	16,245,020	
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	$0	$0	-$4,041,495	$47,649,005	
32							
33		DEPRECIATION			$250,691	$15,117,887	
34		AMORTIZATION OF NATURAL GAS PLANT			0	1,250,806	
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN			0	(420,516)	
36		* AMORTIZATION RE:PROPERTY TAXES			1,046,934	0	
37		* AMORTIZATION RE:USBC			1,352,578	0	
38		* AMORTIZATION RE:COMPENSATED ABSENCES			0	0	
39		* AMORTIZATION RE:			0	0	
40		* AMORTIZATION RE:			0	0	
41		* AMORTIZATION RE:NG MPSC/MCC TAXES			(40,888)	108,296	
42		* PENSION DIFFERENTIAL			(475,643)	(2,554,220)	
43		TAXES OTHER THAN INCOME TAXES			5,697,665	33,975,479	
44		INCOME TAXES - FEDERAL - U.S.	(587,269)	0	(587,269)	1	
45		INCOME TAXES - OTHER	(134,222)	0	(134,222)	0	
46		DEFERRED INCOME TAXES	(280,096)	(1,160,749)	(1,862,193)	(1,796,891)	
47		SUBTOTAL (LINE 33 THRU 46)	($1,001,587)	($1,160,749)	$5,247,653	$45,680,842	
48							
49		TOTAL COST OF SERVICE (LINE 31 + 47)	($1,001,587)	($1,160,749)	$1,206,157	$93,329,847	
50							
51		UTILITY OPERATING INCOME (LINE 15 - 49)	$1,001,587	$1,160,749	$1,276,257	$21,944,224	
52							
53		NATURAL GAS UTILITY RATE BASE	$1,401,486	$0	($11,262,033)	$360,036,181	
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)				6.10%	
55							
56		REQUIRED REVENUE INCREASE	($1,490,260)	($1,924,462)	($3,484,614)	$7,371,955	

	A	B	C	D
1				
2				
3		**NorthWestern Energy**		
4		**Natural Gas Utility - Delivery Services**		
5		**Computation of Required Return and Revenue Increase**		
6				
7				
8				TD&S
9				
10	1	Rate Base		$ 360,036,181
11	2	Rate of Return		7.33%
12	3			
13	4	Net Operating Income		$ 26,390,652
14	5			
15	6	Net Operating Income for the Test Period		$ 21,944,224
16	7			
17	8	Required Incremental Increase in Net Operating Income		$ 4,446,428
18	9			
19	10	Add:		
20	11	MPSC Tax		$ 28,757
21	12	Consumer Counsel Tax		$ 7,372
22	13	Incremental Income Taxes		$ 2,889,398
23	14			
24	15	**Required Revenue Increase/(Decrease)**		**$ 7,371,955**
25	16			
26	17			
27	18	MPSC Tax (0.39%)		$ 28,757
28	19			
29	20	Consumer Counsel Tax (0.10%)		$ 7,372
30	21			
31	22	Taxable Income for State Income Tax		$ 7,335,826
32	23			
33	24	State Income Tax (6.75%) (Unitary Factor = 1.00)		$ 495,168
34	25			
35	26	Taxable Income for Federal Income Tax		$ 6,840,658
36	27			
37	28	Reduction of Federal Income Tax Due to Currrent Year MCLT Paid		$ (173,309)
38	29	Federal Income Tax-Current (35%)		$ 2,567,539
39	30			
40	31	Required Incremental Increase in Net Operating Income		$ 4,446,428

	A	B	C	D	E	F	G	H
1		NORTHWESTERN ENERGY						
2		BATTLE CREEK						
3		INCOME STATEMENT						
4		ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED						
5						REVENUE	SALES &	
6						& REVENUE	ADMINISTRATIVE	
7				BATTLE CREEK	BATTLE CREEK	RELATED	& GENERAL	LABOR
8			BATTLE CREEK	VARIABLE	FIXED	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT
9		REVENUES:						
10		RATE SCHEDULE REVENUES	$2,440,969		$2,440,969	($107,291)		
11		SALES FOR RESALE	59,528		59,528	3,018		
12		PROVISION FOR RATE REFUNDS	-		-	-		
13		TRANSPORTATION	-		-			
14		MISCELLANEOUS REVENUES	115,677		115,677	-		
15		GROSS REVENUES (LINE 10 THRU 14)	$2,616,174	$0	$2,616,174	($104,273)	$0	$0
16								
17		COST OF SERVICE:						
18		PRODUCTION & GATHERING OPERATION	639,043	114,263	524,781			6,375
19		PRODUCTION & GATHERING MAINTENANCE	11,572		11,572			84
20		GAS SUPPLY	(170,795)	(170,795)	-			0
21		STORAGE OPERATION	-		-			0
22		STORAGE MAINTENANCE	-		-			0
23		TRANSMISSION OPERATION	-		-			0
24		TRANSMISSION MAINTENANCE	-		-			0
25		DISTRIBUTION OPERATION	-		-			0
26		DISTRIBUTION MAINTENANCE	-		-			0
27		CUSTOMER ACCOUNTS EXPENSE	-		-			0
28		CUSTOMER SERVICE AND INFORMATION EXPENSE	-		-			0
29		SALES EXPENSE	-		-			0
30		ADMINISTRATIVE AND GENERAL EXPENSE	-		-		871	0
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	479,820	(56,533)	536,352	-	871	6,459
32								
33		DEPRECIATION	179,754		179,754			
34		DEPLETION	610,318		610,318			
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN	-		-			
36		* AMORTIZATION RE:PROPERTY TAXES	-		-			
37		* AMORTIZATION RE:USBC	-		-			
38		* AMORTIZATION RE:COMPENSATED ABSENCES	-		-			
39		* AMORTIZATION RE:	-		-			
40		* AMORTIZATION RE:	-		-			
41		* AMORTIZATION RE:NG MPSC/MCC TAXES	-		-			
42		* PENSION DIFFERENTIAL	-		-			
43		TAXES OTHER THAN INCOME TAXES	121,717	61,465	60,251	$1,828		452
44		INCOME TAXES - FEDERAL - U.S.	(658,360)		(658,360)	0	0	0
45		INCOME TAXES - OTHER	(136,160)		(136,160)	0	0	0
46		DEFERRED INCOME TAXES	1,180,451	(1,943)	1,182,394	(41,790)	(343)	(2,722)
47		SUBTOTAL (LINE 33 THRU 46)	1,297,720	59,522	1,238,198	(39,962)	(343)	(2,270)
48								
49		TOTAL COST OF SERVICE (LINE 31 + 47)	1,777,540	2,990	1,774,550	(39,962)	528	4,189
50								
51		UTILITY OPERATING INCOME (LINE 15 - 49)	838,634	(2,990)	841,624	(64,311)	(528)	(4,189)
52								
53		NATURAL GAS UTILITY RATE BASE	$8,579,130		$8,579,130			
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)	9.78%		9.81%			
55								
56		REQUIRED REVENUE INCREASE			($352,769)	$106,625	$875	$6,946

	A	B	I	J	K	L	M	N
1		NORTHWESTERN ENERGY						
2		BATTLE CREEK						
3		INCOME STATEMENT						
4		ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED						
5								
6				DEPRECIATION		ALLOCATION OF	TAXES - OTHER	WORKING
7			ONE-TIME	AND DEPLETION	AMORTIZATION	GAS PRODUCTION	THAN INCOME	CAPITAL
8			ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADMINISTRATION	ADJUSTMENT	ADJUSTMENT
9		REVENUES:						
10		RATE SCHEDULE REVENUES				0		
11		SALES FOR RESALE				0		
12		PROVISION FOR RATE REFUNDS				0		
13		TRANSPORTATION				0		
14		MISCELLANEOUS REVENUES				0		
15		GROSS REVENUES (LINE 10 THRU 14)	$0	$0	$0	$0	$0	$0
16								
17		COST OF SERVICE:						
18		PRODUCTION & GATHERING OPERATION	(18,375)			30,875		
19		PRODUCTION & GATHERING MAINTENANCE	(847)			0		
20		GAS SUPPLY				0		
21		STORAGE OPERATION				0		
22		STORAGE MAINTENANCE				0		
23		TRANSMISSION OPERATION				0		
24		TRANSMISSION MAINTENANCE				0		
25		DISTRIBUTION OPERATION				9,466		
26		DISTRIBUTION MAINTENANCE				0		
27		CUSTOMER ACCOUNTS EXPENSE				39,693		
28		CUSTOMER SERVICE AND INFORMATION EXPENSE				39,857		
29		SALES EXPENSE				0		
30		ADMINISTRATIVE AND GENERAL EXPENSE	18,375			464,038		
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	(847)	-	-	583,929	-	-
32								
33		DEPRECIATION		(156,265)		40,693		
34		DEPLETION		(122,573)		10,344		
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN				0		
36		* AMORTIZATION RE:PROPERTY TAXES				0		
37		* AMORTIZATION RE:USBC				0		
38		* AMORTIZATION RE:COMPENSATED ABSENCES				0		
39		* AMORTIZATION RE:				0		
40		* AMORTIZATION RE:				0		
41		* AMORTIZATION RE:NG MPSC/MCC TAXES			(232)	0		
42		* PENSION DIFFERENTIAL				(54,354)		
43		TAXES OTHER THAN INCOME TAXES				2,542	2,898	
44		INCOME TAXES - FEDERAL - U.S.	0	0	0	0	0	0
45		INCOME TAXES - OTHER	0	0	0	0	0	0
46		DEFERRED INCOME TAXES	334	97,593	81	(289,596)	(1,141)	0
47		SUBTOTAL (LINE 33 THRU 46)	334	(181,245)	(151)	(290,371)	1,757	-
48								
49		TOTAL COST OF SERVICE (LINE 31 + 47)	(513)	(181,245)	(151)	293,558	1,757	-
50								
51		UTILITY OPERATING INCOME (LINE 15 - 49)	513	$181,245	151	(293,558)	(1,757)	-
52								
53		NATURAL GAS UTILITY RATE BASE		61,225	-582			($241,893)
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)						
55								
56		REQUIRED REVENUE INCREASE	($850)	($293,054)	($321)	$486,705	$2,913	($29,397)

	A	B	O	P	Q	R
1		NORTHWESTERN ENERGY				
2		BATTLE CREEK				
3		INCOME STATEMENT				
4		ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED				
5						
6				INTEREST	TOTAL	TEST PERIOD
7			INCOME TAX	SYNCHRONIZATION	UPDATES &	@ PRESENT
8			ADJUSTMENT	ADJUSTMENT	ADJUSTMENTS	RATES
9		REVENUES:				
10		RATE SCHEDULE REVENUES			($107,291)	$2,333,679
11		SALES FOR RESALE			3,018	62,546
12		PROVISION FOR RATE REFUNDS			0	0
13		TRANSPORTATION			0	0
14		MISCELLANEOUS REVENUES			0	115,677
15		GROSS REVENUES (LINE 10 THRU 14)	$0	$0	($104,273)	$2,511,901
16						
17		COST OF SERVICE:				
18		PRODUCTION & GATHERING OPERATION			18,875	543,655
19		PRODUCTION & GATHERING MAINTENANCE			(762)	10,809
20		GAS SUPPLY			0	0
21		STORAGE OPERATION			0	0
22		STORAGE MAINTENANCE			0	0
23		TRANSMISSION OPERATION			0	0
24		TRANSMISSION MAINTENANCE			0	0
25		DISTRIBUTION OPERATION			9,466	9,466
26		DISTRIBUTION MAINTENANCE			0	0
27		CUSTOMER ACCOUNTS EXPENSE			39,693	39,693
28		CUSTOMER SERVICE AND INFORMATION EXPENSE			39,857	39,857
29		SALES EXPENSE			0	0
30		ADMINISTRATIVE AND GENERAL EXPENSE			483,284	483,284
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	-	-	590,413	1,126,765
32						
33		DEPRECIATION			(115,572)	64,182
34		DEPLETION			(112,229)	498,089
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN			0	0
36		* AMORTIZATION RE:PROPERTY TAXES			0	0
37		* AMORTIZATION RE:USBC			0	0
38		* AMORTIZATION RE:COMPENSATED ABSENCES			0	0
39		* AMORTIZATION RE:			0	0
40		* AMORTIZATION RE:			0	0
41		* AMORTIZATION RE:NG MPSC/MCC TAXES			(232)	(232)
42		* PENSION DIFFERENTIAL			(54,354)	(54,354)
43		TAXES OTHER THAN INCOME TAXES			7,720	67,971
44		INCOME TAXES - FEDERAL - U.S.	658,360	0	658,360	0
45		INCOME TAXES - OTHER	136,160	0	136,160	0
46		DEFERRED INCOME TAXES	(674,263)	(84,346)	(996,193)	186,201
47		SUBTOTAL (LINE 33 THRU 46)	120,257	(84,346)	(476,341)	761,857
48						
49		TOTAL COST OF SERVICE (LINE 31 + 47)	120,257	(84,346)	114,072	1,888,622
50						
51		UTILITY OPERATING INCOME (LINE 15 - 49)	(120,257)	84,346	(218,345)	623,279
52						
53		NATURAL GAS UTILITY RATE BASE	$215,341	$0	34,091	$8,613,221
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)				7.24%
55						
56		REQUIRED REVENUE INCREASE	$225,550	($139,841)	$366,151	$13,382

	A	B	C	D	E	F	G	H	I	J
1		NORTHWESTERN ENERGY								
2		BEAR PAW (NFR)								
3		INCOME STATEMENT								
4		ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED								
5						REVENUE	SALES &			
6						& REVENUE	ADMINISTRATIVE			DEPRECIATION
7				BEAR PAW	BEAR PAW	RELATED	& GENERAL	LABOR	ONE-TIME	AND DEPLETION
8			BEAR PAW	VARIABLE	FIXED	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT
9		REVENUES:								
10		RATE SCHEDULE REVENUES	$4,089,675		$4,089,675	($882,518)				
11		SALES FOR RESALE	72,732		72,732	(2,603)				
12		PROVISION FOR RATE REFUNDS	2,011,580		2,011,580	(2,011,580)				
13		TRANSPORTATION	644,388		644,388	-				
14		MISCELLANEOUS REVENUES	354,292		354,292	-			0	
15		GROSS REVENUES (LINE 10 THRU 14)	$7,172,667	$0	$7,172,667	($2,896,701)	$0	$0	$0	$0
16										
17		COST OF SERVICE:								
18		PRODUCTION & GATHERING OPERATION	2,247,789	267,347	1,980,442			16,909	$ (135,762)	
19		PRODUCTION & GATHERING MAINTENANCE	292,448		292,448			2,377	(55,645)	
20		GAS SUPPLY	(338,171)	(338,171)	-			0		
21		STORAGE OPERATION	-		-			0		
22		STORAGE MAINTENANCE	-		-			0		
23		TRANSMISSION OPERATION	-		-			0		
24		TRANSMISSION MAINTENANCE	-		-			0		
25		DISTRIBUTION OPERATION	-		-			0		
26		DISTRIBUTION MAINTENANCE	-		-			0		
27		CUSTOMER ACCOUNTS EXPENSE	-		-			0		
28		CUSTOMER SERVICE AND INFORMATION EXPENSE	-		-			0		
29		SALES EXPENSE	-		-			0		
30		ADMINISTRATIVE AND GENERAL EXPENSE	-		-		(1,893)	0	45,906	
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	2,202,066	(70,824)	2,272,890	-	(1,893)	19,286	(145,501)	-
32										
33		DEPRECIATION	-		-					62,228
34		DEPLETION	1,449,618		1,449,618					(204,161)
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN	-		-					
36		* AMORTIZATION RE:PROPERTY TAXES	-		-					
37		* AMORTIZATION RE:USBC	-		-					
38		* AMORTIZATION RE:COMPENSATED ABSENCES	-		-					
39		* AMORTIZATION RE:	-		-					
40		* AMORTIZATION RE:	-		-					
41		* AMORTIZATION RE:NG MPSC/MCC TAXES	-		-					
42		* PENSION DIFFERENTIAL	-		-					
43		TAXES OTHER THAN INCOME TAXES	284,503	70,985	213,517	$672		1,350		
44		INCOME TAXES - FEDERAL - U.S.	(216,406)		(216,406)	0	0	0	0	0
45		INCOME TAXES - OTHER	(44,757)		(44,757)	0	0	0	0	0
46		DEFERRED INCOME TAXES	1,645,126	(64)	1,645,190	(1,141,203)	746	(8,128)	57,309	49,677
47		SUBTOTAL (LINE 33 THRU 47)	3,118,083	70,921	3,047,162	(1,140,531)	746	(6,778)	57,309	(92,256)
48										
49		TOTAL COST OF SERVICE (LINE 31 + 47)	5,320,149	98	5,320,051	(1,140,531)	(1,147)	12,508	(88,192)	(92,256)
50										
51		UTILITY OPERATING INCOME (LINE 15 - 49)	1,852,518	(98)	1,852,616	(1,756,169)	1,147	(12,508)	88,192	92,256
52										
53		NATURAL GAS UTILITY RATE BASE	$11,456,825		$11,456,825				0	102,295
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)	16.17%		16.17%					
55										
56		REQUIRED REVENUE INCREASE			($1,679,222)	$2,911,638	($1,902)	$20,738	($146,217)	($140,525)

	A	B	K	L	M	N	O	P	Q
1		NORTHWESTERN ENERGY							
2		BEAR PAW (NFR)							
3		INCOME STATEMENT							
4		ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED							
5									
6			ALLOCATION OF	TAXES - OTHER	WORKING		INTEREST	TOTAL	TEST PERIOD
7			GAS PRODUCTION	THAN INCOME	CAPITAL	INCOME TAX	SYNCHRONIZATION	UPDATES &	@ PRESENT
8			ADMINISTRATION	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENTS	RATES
9		REVENUES:							
10		RATE SCHEDULE REVENUES	0					($882,518)	$3,207,157
11		SALES FOR RESALE	0					(2,603)	70,129
12		PROVISION FOR RATE REFUNDS	0					(2,011,580)	0
13		TRANSPORTATION	0					0	644,388
14		MISCELLANEOUS REVENUES	0					0	354,292
15		GROSS REVENUES (LINE 10 THRU 14)	$0	$0	$0	$0	$0	($2,896,701)	$4,275,966
16									
17		COST OF SERVICE:							
18		PRODUCTION & GATHERING OPERATION	47,844					(71,008)	1,909,433
19		PRODUCTION & GATHERING MAINTENANCE	0					(53,268)	239,180
20		GAS SUPPLY	0					0	0
21		STORAGE OPERATION	0					0	0
22		STORAGE MAINTENANCE	0					0	0
23		TRANSMISSION OPERATION	0					0	0
24		TRANSMISSION MAINTENANCE	0					0	0
25		DISTRIBUTION OPERATION	14,669					14,669	14,669
26		DISTRIBUTION MAINTENANCE	0					0	0
27		CUSTOMER ACCOUNTS EXPENSE	61,509					61,509	61,509
28		CUSTOMER SERVICE AND INFORMATION EXPENSE	61,764					61,764	61,764
29		SALES EXPENSE	0					0	0
30		ADMINISTRATIVE AND GENERAL EXPENSE	719,085					763,097	763,097
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	904,871	-	-	-	-	776,762	3,049,652
32									
33		DEPRECIATION	63,059					125,287	125,287
34		DEPLETION	16,029					(188,132)	1,261,486
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN	0					0	0
36		* AMORTIZATION RE:PROPERTY TAXES	0					0	0
37		* AMORTIZATION RE:USBC	0					0	0
38		* AMORTIZATION RE:COMPENSATED ABSENCES	0					0	0
39		* AMORTIZATION RE:	0					0	0
40		* AMORTIZATION RE:	0					0	0
41		* AMORTIZATION RE:NG MPSC/MCC TAXES	0					0	0
42		* PENSION DIFFERENTIAL	(84,228)					(84,228)	(84,228)
43		TAXES OTHER THAN INCOME TAXES	3,939	64,109				70,069	283,586
44		INCOME TAXES - FEDERAL - U.S.	0	0	0	216,406	0	216,406	0
45		INCOME TAXES - OTHER	0	0	0	44,756	0	44,756	(1)
46		DEFERRED INCOME TAXES	(448,763)	(25,251)	0	(159,552)	(282,571)	(1,957,736)	(312,546)
47		SUBTOTAL (LINE 33 THRU 47)	(449,964)	38,858	-	101,610	(282,571)	(1,773,578)	1,273,584
48									
49		TOTAL COST OF SERVICE (LINE 31 + 47)	454,907	38,858	-	101,610	(282,571)	(996,815)	4,323,236
50									
51		UTILITY OPERATING INCOME (LINE 15 - 49)	(454,907)	(38,858)	-	(101,610)	282,571	(1,899,885)	(47,270)
52									
53		NATURAL GAS UTILITY RATE BASE			($634,495)	$880,873		348,673	$11,805,498
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)							-0.40%
55									
56		REQUIRED REVENUE INCREASE	$754,212	$64,424	($77,108)	$275,515	($468,488)	$3,192,287	$1,513,065

	A	B	C	D	E	F	G	H	I	J
1		NORTHWESTERN ENERGY								
2		SOUTH BEAR PAW (Devon)								
3		INCOME STATEMENT								
4		ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED								
5						REVENUE	SALES &			
6						& REVENUE	ADMINISTRATIVE			DEPRECIATION
7				SOUTH BEAR	SOUTH BEAR	RELATED	& GENERAL	LABOR	ONE-TIME	AND DEPLETION
8			SOUTH BEAR	VARIABLE	FIXED	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT
9		REVENUES:								
10		RATE SCHEDULE REVENUES	$17,062,651		$17,062,651	($2,304,068)				
11		SALES FOR RESALE	184,783		184,783	(1,802)				
12		PROVISION FOR RATE REFUNDS	(3,190,519)		(3,190,519)	3,190,519				
13		TRANSPORTATION	971,873		971,873	-				
14		MISCELLANEOUS REVENUES	536,657		536,657	-				
15		GROSS REVENUES (LINE 10 THRU 14)	$15,565,445	$0	$15,565,445	$884,649	$0	$0	$0	$0
16										
17		COST OF SERVICE:								
18		PRODUCTION & GATHERING OPERATION	7,270,773	1,356,666	5,914,106			41,223	(205,671)	
19		PRODUCTION & GATHERING MAINTENANCE	210,639		210,639			3,322	(17,485)	
20		GAS SUPPLY	(1,875,532)	(1,875,532)	-			0		
21		STORAGE OPERATION	-		-			0		
22		STORAGE MAINTENANCE	-		-			0		
23		TRANSMISSION OPERATION	-		-			0		
24		TRANSMISSION MAINTENANCE	-		-			0		
25		DISTRIBUTION OPERATION	-		-			0		
26		DISTRIBUTION MAINTENANCE	-		-			0		
27		CUSTOMER ACCOUNTS EXPENSE	-		-			0		
28		CUSTOMER SERVICE AND INFORMATION EXPENSE	-		-			0		
29		SALES EXPENSE	-		-			0		
30		ADMINISTRATIVE AND GENERAL EXPENSE	-		-		(20,155)	0	143,835	
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	5,605,880	(518,866)	6,124,746	-	(20,155)	44,545	(79,320)	-
32										
33		DEPRECIATION	-		-					146,319
34		DEPLETION	4,310,725		4,310,725					(19,921)
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN	-		-					
36		* AMORTIZATION RE:PROPERTY TAXES	-		-					
37		* AMORTIZATION RE:USBC	-		-					
38		* AMORTIZATION RE:COMPENSATED ABSENCES	-		-					
39		* AMORTIZATION RE:	-		-					
40		* AMORTIZATION RE:	-		-					
41		* AMORTIZATION RE:NG MPSC/MCC TAXES	-		-					
42		* PENSION DIFFERENTIAL	-		-					
43		TAXES OTHER THAN INCOME TAXES	868,186	505,698	362,488	$5,023		3,118		
44		INCOME TAXES - FEDERAL - U.S.	(717,458)		(717,458)	0	0	0	0	0
45		INCOME TAXES - OTHER	(148,383)		(148,383)	0	0	0	0	0
46		DEFERRED INCOME TAXES	2,292,016	5,186	2,286,830	346,463	7,939	(18,773)	31,242	(44,239)
47		SUBTOTAL (LINE 33 THRU 46)	6,605,085	510,884	6,094,201	351,486	7,939	(15,655)	31,242	82,159
48										
49		TOTAL COST OF SERVICE (LINE 31 + 47)	12,210,965	(7,982)	12,218,947	351,486	(12,216)	28,890	(48,078)	82,159
50										
51		UTILITY OPERATING INCOME (LINE 15 - 49)	3,354,480	7,982	3,346,498	533,163	12,216	(28,890)	48,078	(82,159)
52										
53		NATURAL GAS UTILITY RATE BASE	$53,541,260		$53,541,260					9,357
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)	6.27%		6.25%					
55										
56		REQUIRED REVENUE INCREASE			$958,420	($883,957)	($20,253)	$47,898	($79,711)	$137,353

	A	B	K	L	M	N	O	P	Q
1		NORTHWESTERN ENERGY							
2		SOUTH BEAR PAW (Devon)							
3		INCOME STATEMENT							
4		ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED							
5									
6			ALLOCATION OF	TAXES - OTHER	WORKING		INTEREST	TOTAL	TEST PERIOD
7			GAS PRODUCTION	THAN INCOME	CAPITAL	INCOME TAX	SYNCHRONIZATION	UPDATES &	@ PRESENT
8			ADMINISTRATION	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENTS	RATES
9		REVENUES:							
10		RATE SCHEDULE REVENUES	0					($2,304,068)	$14,758,583
11		SALES FOR RESALE	0					(1,802)	182,981
12		PROVISION FOR RATE REFUNDS	0					3,190,519	0
13		TRANSPORTATION	0					0	971,873
14		MISCELLANEOUS REVENUES	0					0	536,657
15		GROSS REVENUES (LINE 10 THRU 14)	$0	$0	$0	$0	$0	$884,649	$16,450,094
16									
17		COST OF SERVICE:							
18		PRODUCTION & GATHERING OPERATION	589,844					425,396	6,339,502
19		PRODUCTION & GATHERING MAINTENANCE	0					(14,163)	196,477
20		GAS SUPPLY	0					0	0
21		STORAGE OPERATION	0					0	0
22		STORAGE MAINTENANCE	0					0	0
23		TRANSMISSION OPERATION	0					0	0
24		TRANSMISSION MAINTENANCE	0					0	0
25		DISTRIBUTION OPERATION	27,424					27,424	27,424
26		DISTRIBUTION MAINTENANCE	0					0	0
27		CUSTOMER ACCOUNTS EXPENSE	114,989					114,989	114,989
28		CUSTOMER SERVICE AND INFORMATION EXPENSE	115,466					115,466	115,466
29		SALES EXPENSE	0					0	0
30		ADMINISTRATIVE AND GENERAL EXPENSE	1,344,315					1,467,996	1,467,996
31		TOTAL O & M EXPENSE (LINE 18 THRU 30)	2,192,039	-	-	-	-	2,137,108	8,261,854
32									
33		DEPRECIATION	117,888					264,206	264,206
34		DEPLETION	29,966					10,045	4,320,770
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN	0					0	0
36		* AMORTIZATION RE:PROPERTY TAXES	0					0	0
37		* AMORTIZATION RE:USBC	0					0	0
38		* AMORTIZATION RE:COMPENSATED ABSENCES	0					0	0
39		* AMORTIZATION RE:	0					0	0
40		* AMORTIZATION RE:	0					0	0
41		* AMORTIZATION RE:NG MPSC/MCC TAXES	0					0	0
42		* PENSION DIFFERENTIAL	(157,463)					(157,463)	(157,463)
43		TAXES OTHER THAN INCOME TAXES	7,364	19,227				34,732	397,219
44		INCOME TAXES - FEDERAL - U.S.	0	0	0	717,458	0	717,458	0
45		INCOME TAXES - OTHER	0	0	0	148,383	0	148,383	0
46		DEFERRED INCOME TAXES	(838,954)	(7,573)	0	(596,259)	(385,402)	(1,505,556)	781,274
47		SUBTOTAL (LINE 33 THRU 46)	(841,200)	11,654	-	269,582	(385,402)	(488,194)	5,606,007
48									
49		TOTAL COST OF SERVICE (LINE 31 + 47)	1,350,839	11,654	-	269,582	(385,402)	1,648,914	13,867,861
50									
51		UTILITY OPERATING INCOME (LINE 15 - 49)	(1,350,839)	(11,654)	-	(269,582)	385,402	(764,265)	2,582,233
52									
53		NATURAL GAS UTILITY RATE BASE			($1,717,534)	($196,714)		(1,904,890)	$51,636,370
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 51 / 53)							5.00%
55									
56		REQUIRED REVENUE INCREASE	$2,239,623	$19,321	($208,728)	$423,047	($638,977)	$1,035,616	$1,994,036

	A	B	C	D	E	F	G	H	I	J
1		NORTHWESTERN ENERGY								
2		PRODUCTION ADMINISTRATION UTILITY								
3		INCOME STATEMENT								
4		ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED								
5				SALES &						
6				ADMINISTRATIVE			CORPORATE			
7			PRODUCTION	& GENERAL	LABOR	ONE-TIME	ALLOCATIONS	DEPRECIATION	AMORTIZATION	INCOME TAX
8			ADMINISTRATION	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT	ADJUSTMENT
9		REVENUES:								
10		RATE SCHEDULE REVENUES	$0							
11		SALES FOR RESALE	-							
12		PROVISION FOR RATE REFUNDS	-							
13		TRANSPORTATION	-							
14		MISCELLANEOUS REVENUES	-							
15		GROSS REVENUES (LINE 2 THRU 6)	$0	$0	$0	$0	$0	$0	$0	$0
16										
17		COST OF SERVICE:								
18		PRODUCTION & GATHERING OPERATION	226,104		6,037	-				
19		PRODUCTION & GATHERING MAINTENANCE	-		0					
20		GAS SUPPLY	-		0					
21		STORAGE OPERATION	-		0					
22		STORAGE MAINTENANCE	-		0					
23		TRANSMISSION OPERATION	-		0					
24		TRANSMISSION MAINTENANCE	-		0					
25		DISTRIBUTION OPERATION	56,914	0	0		14,262			
26		DISTRIBUTION MAINTENANCE	-		0					
27		CUSTOMER ACCOUNTS EXPENSE	242,803	(3,226)	0	1,513	57,351			
28		CUSTOMER SERVICE AND INFORMATION EXPENSE	236,150	0	0		63,529			
29		SALES EXPENSE	34,713	(34,713)	0		0			
30		ADMINISTRATIVE AND GENERAL EXPENSE	2,744,675	(58,314)	(7,290)		809,938			
31		TOTAL O & M EXPENSE (LINE 10 THRU 22)	3,541,359	(96,253)	(1,253)	1,513	945,080	-	-	-
32										
33		DEPRECIATION	349,621					(43,658)		
34		AMORTIZATION OF NATURAL GAS PLANT	77,773			-				
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN	-							
36		* AMORTIZATION RE:PROPERTY TAXES	-							
37		* AMORTIZATION RE:USBC	-							
38		* AMORTIZATION RE:COMPENSATED ABSENCES	-							
39		* AMORTIZATION RE:	-							
40		* AMORTIZATION RE:	-							
41		* AMORTIZATION RE:NG MPSC/CC TAXES	24,288						(24,288)	
42		* PENSION DIFFERENTIAL	(332,572)						(76,103)	
43		TAXES OTHER THAN INCOME TAXES	18,592		520	-				
44		INCOME TAXES - FEDERAL - U.S.	(11,569,619)	0	0	0	0	0	0	11,569,619
45		INCOME TAXES - OTHER	(2,392,797)	0	0	0	0	0	0	2,392,797
46		DEFERRED INCOME TAXES	11,188,587	37,912	289	(596)	(372,243)	15,280	39,541	(13,908,509)
47		SUBTOTAL (LINE 25 THRU 38)	(2,636,128)	37,912	809	(596)	(372,243)	(28,378)	(60,850)	53,907
48										
49		TOTAL COST OF SERVICE (LINE 23 + 39)	905,231	(58,341)	(445)	917	572,837	(28,378)	(60,850)	53,907
50										
51		UTILITY OPERATING INCOME (LINE 7 - 41)	(905,231)	58,341	445	(917)	(572,837)	28,378	60,850	(53,907)
52										
53		NATURAL GAS UTILITY RATE BASE								$0
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 43 / 45)								
55										
56		REQUIRED REVENUE INCREASE	$1,500,826	($96,726)	($739)	$1,521	$949,735	($47,048)	($100,885)	$89,375

	A	B	K	L	M	N	O	P	Q	R
1		NORTHWESTERN ENERGY								
2		PRODUCTION ADMINISTRATION UTILITY								
3		INCOME STATEMENT								
4		ACTUAL 12 MONTHS ENDED DECEMBER 2015 - ADJUSTED					Percentage Split Production Administration			
5							13.30%	20.61%	38.53%	27.56%
6			INTEREST	TOTAL	TEST PERIOD					HPC
7			SYNCHRONIZATION	UPDATES &	@ PRESENT		BATTLE	BEAR	SOUTH	REMAINING
8			ADJUSTMENT	ADJUSTMENTS	RATES		CREEK	PAW	BEAR PAW	BALANCE
9		REVENUES:								
10		RATE SCHEDULE REVENUES		$0	$0		0	0	0	0
11		SALES FOR RESALE		0	0		0	0	0	0
12		PROVISION FOR RATE REFUNDS		0	0		0	0	0	0
13		TRANSPORTATION		0	0		0	0	0	0
14		MISCELLANEOUS REVENUES		0	0		0	0	0	0
15		GROSS REVENUES (LINE 2 THRU 6)	$0	$0	$0		$0	$0	$0	$0
16										
17		COST OF SERVICE:								
18		PRODUCTION & GATHERING OPERATION		6,037	232,141		30,875	47,844	89,444	63,978
19		PRODUCTION & GATHERING MAINTENANCE		0	0		0	0	0	0
20		GAS SUPPLY		0	0		0	0	0	0
21		STORAGE OPERATION		0	0		0	0	0	0
22		STORAGE MAINTENANCE		0	0		0	0	0	0
23		TRANSMISSION OPERATION		0	0		0	0	0	0
24		TRANSMISSION MAINTENANCE		0	0		0	0	0	0
25		DISTRIBUTION OPERATION		14,262	71,176		9,466	14,669	27,424	19,616
26		DISTRIBUTION MAINTENANCE		0	0		0	0	0	0
27		CUSTOMER ACCOUNTS EXPENSE		55,637	298,440		39,693	61,509	114,989	82,250
28		CUSTOMER SERVICE AND INFORMATION EXPENSE		63,529	299,679		39,857	61,764	115,466	82,591
29		SALES EXPENSE		(34,713)	0		0	0	0	0
30		ADMINISTRATIVE AND GENERAL EXPENSE		744,335	3,489,009		464,038	719,085	1,344,315	961,571
31		TOTAL O & M EXPENSE (LINE 10 THRU 22)	-	849,086	4,390,445		583,929	904,871	1,691,639	1,210,007
32										
33		DEPRECIATION		(43,658)	305,963		40,693	63,059	117,888	84,323
34		AMORTIZATION OF NATURAL GAS PLANT		0	77,773		10,344	16,029	29,966	21,434
35		* AMORTIZATION RE:CUSHION GAS DEFERRED GAIN		0	0		0	0	0	0
36		* AMORTIZATION RE:PROPERTY TAXES		0	0		0	0	0	0
37		* AMORTIZATION RE:USBC		0	0		0	0	0	0
38		* AMORTIZATION RE:COMPENSATED ABSENCES		0	0		0	0	0	0
39		* AMORTIZATION RE:		0	0		0	0	0	0
40		* AMORTIZATION RE:		0	0		0	0	0	0
41		* AMORTIZATION RE:NG MPSC/CC TAXES		(24,288)	0		0	0	0	0
42		* PENSION DIFFERENTIAL		(76,103)	(408,675)		(54,354)	(84,228)	(157,463)	(112,631)
43		TAXES OTHER THAN INCOME TAXES		520	19,111		2,542	3,939	7,364	5,267
44		INCOME TAXES - FEDERAL - U.S.	0	11,569,619	0		0	0	0	0
45		INCOME TAXES - OTHER	0	2,392,797	0		0	0	0	0
46		DEFERRED INCOME TAXES	822,330	(13,365,996)	(2,177,409)		(289,595)	(448,764)	(838,956)	(600,094)
47		SUBTOTAL (LINE 25 THRU 38)	822,330	452,891	(2,183,237)		(290,371)	(449,965)	(841,201)	(601,700)
48										
49		TOTAL COST OF SERVICE (LINE 23 + 39)	822,330	1,301,977	2,207,208		293,559	454,906	850,437	608,307
50										
51		UTILITY OPERATING INCOME (LINE 7 - 41)	(822,330)	(1,301,977)	(2,207,208)		(293,559)	(454,906)	(850,437)	(608,307)
52										
53		NATURAL GAS UTILITY RATE BASE		0	$0					
54		RATE OF RETURN EARNED (%) MPSC BASIS (LINE 43 / 45)								
55										
56		REQUIRED REVENUE INCREASE	$1,363,380	$2,158,613	$3,659,439					

	A	B	C	D	E	F	G	H
1								
2								
3		**NorthWestern Energy**						
4		**Natural Gas Utility - Production Assets**						
5		**Computation of Required Return and Revenue Increase**						
6								
7						Bear Paw		South Bear Paw
8				Battle Creek		(NFR)		(Devon)
9								
10	1	Rate Base		$ 8,613,221		$ 11,805,498		$ 51,636,370
11	2	Rate of Return		7.33%		7.33%		7.33%
12	3							
13	4	Net Operating Income		$ 631,349		$ 865,343		$ 3,784,946
14	5							
15	6	Net Operating Income for the Test Period		$ 623,279		$ (47,270)		$ 2,582,233
16	7							
17	8	Required Incremental Increase in Net Operating Income		$ 8,070		$ 912,613		$ 1,202,713
18	9							
19	10	Add:						
20	11	MPSC Tax		$ 55		$ 5,901		$ 7,776
21	12	Consumer Counsel Tax		$ 13		$ 1,513		$ 1,994
22	13	Incremental Income Taxes		$ 5,244		$ 593,038		$ 781,553
23	14							
24	15	**Required Revenue Increase/(Decrease)**		**$ 13,382**		**$ 1,513,065**		**$ 1,994,036**
25	16							
26	17							
27	18	MPSC Tax (0.39%)		$ 55		$ 5,901		$ 7,776
28	19							
29	20	Consumer Counsel Tax (0.10%)		$ 13		$ 1,513		$ 1,994
30	21							
31	22	Taxable Income for State Income Tax		$ 13,314		$ 1,505,651		$ 1,984,266
32	23							
33	24	State Income Tax (6.75%) (Unitary Factor = 1.00)		$ 899		$ 101,631		$ 133,938
34	25							
35	26	Taxable Income for Federal Income Tax		$ 12,415		$ 1,404,020		$ 1,850,328
36	27							
37	28	Reduction of Federal Income Tax Due to Currrent Year MCLT Paid		$ (315)		$ (35,571)		$ (46,878)
38	29	Federal Income Tax-Current (35%)		$ 4,660		$ 526,978		$ 694,493
39	30							
40	31	Required Incremental Increase in Net Operating Income		$ 8,070		$ 912,613		$ 1,202,713

NorthWestern Energy

NorthWestern Energy
Natural Gas Utility
12 Months Ended December 2015

Natural Gas Revenue Summary

	A	B	C	D	E	F	L	M	N	O	P	Q	R
7		Actual					Test Period						
9		Avg. Cust. Nos.	MDDQ	Market (Dkt)	Revenues @ Current Base Rates		Avg. Cust. Nos.	MDDQ	Market (Dkt)	Revenues @ Current Base Rates	Revenues @ Uniform Design Rates	Revenue Change (P) vs. (Q)	Percent Change (P) vs. (Q)
10	Core - DBU												
11	RESIDENTIAL:												
12	Residential	165,787		11,684,807	$ 57,965,500		165,787		12,452,351	$ 60,820,434	$ 64,718,252	$ 3,897,818	6.41%
13	Employee	284		26,584	$ 92,799		284		28,206	$ 97,326	$ 103,569	$ 6,243	6.41%
14	Subtotal	166,071		11,711,391	$ 58,058,299		166,071		12,480,557	$ 60,917,760	$ 64,821,820	$ 3,904,061	6.41%
15													
16	GENERAL SERVICE:												
17	Commercial	22,943		6,162,105	$ 29,383,581		22,943		6,512,452	$ 30,643,035	$ 32,614,668	$ 1,971,633	6.43%
18	Industrial Firm	263		151,636	$ 646,027		263		160,252	$ 677,000	$ 720,586	$ 43,586	6.44%
19	G & M	90		56,630	$ 245,456		90		60,404	$ 259,026	$ 275,704	$ 16,679	6.44%
20	Interdepart.	62		55,377	$ 226,324		62		58,825	$ 238,718	$ 254,088	$ 15,371	6.44%
21	Total - Gen. Ser.	23,359		6,425,748	$ 30,501,387		23,359		6,791,933	$ 31,817,779	$ 33,865,047	$ 2,047,268	6.43%
22													
23	Total Core - DBU	189,430		18,137,138	$ 88,559,687		189,430		19,272,490	$ 92,735,539	$ 98,686,868	$ 5,951,329	6.42%
24													
25	Utilities	4		209,502	$ 327,850		4		233,901	$ 330,096	$ 351,357	$ 21,261	6.44%
26	Transmission		2,751					2,751					
27	Storage		1,513					1,513					
28													
29	Non-Core												
30	DBU Transportation												
31	Firm Transportation	224	21,403		$ 2,386,159		224	21,403		$ 2,408,640	$ 2,563,859	$ 155,219	6.44%
32	Interruptible Transportation			135,360	$ 34,448				135,360	$ 34,448	$ 36,667	$ 2,218	6.44%
33													
34	TBU Transportation												
35	Firm Transportation	32	101,220	17,506,478	$ 13,006,109		32	101,220	17,506,478	$ 13,006,109	$ 13,836,134	$ 830,026	6.38%
36	Interruptible Transportation			6,035,341	$ 2,442,349				6,035,341	$ 2,442,349	$ 2,599,628	$ 157,279	6.44%
37													
38	Storage		45,740		$ 3,520,419			45,740		$ 3,520,419	$ 3,747,114	$ 226,695	6.44%
39													
40	Total Montana (Distr., Transp & Storage)	189,690		42,023,819	$ 110,277,021		189,690		43,183,570	$ 114,477,601	$ 121,821,627	$ 7,344,026	6.42%
41													
42	Off-System IT			131,647	$ 12,487				131,647	$ 12,487	$ 12,487	$ -	
43													
44													
45	CMPL Transportation				$ 170,464					$ 170,464	$ 170,464	$ -	
46													
47	Miscellaneous Revenues				$ 1,149,823					$ 613,520	$ 613,520	$ -	
48													
49	Rounding											$ 27,929	
50													
51	Total	189,690		42,155,466	$ 111,609,795		189,690		43,315,217	$ 115,274,072	$ 122,618,098	$ 7,371,955	6.40%
52													

NorthWestern Energy

NorthWestern Energy
12 Months Ended December 2015
Natural Gas Utility

Number of Customers

Line No.	(A)	(B) Total	(C) January	(D) February	(E) March	(F) April	(G) May	(H) June	(I) July	(J) August	(K) September	(L) October	(M) November	(N) December
1	**Core - DBU**													
2														
3	RESIDENTIAL:													
4	Residential	165,787	165,179	165,296	165,505	165,644	165,691	165,666	165,533	165,467	165,646	166,097	166,652	167,066
5	Employee	284	293	292	290	289	288	284	282	280	280	278	278	275
6	Total - Residential	166,071	165,472	165,588	165,795	165,933	165,979	165,950	165,815	165,747	165,926	166,375	166,930	167,341
7														
8	General Service:													
9	Commercial 0 - 300	14,929	15,237	15,253	15,277	15,206	15,169	15,120	15,035	14,378	14,498	14,546	14,665	14,763
10	301 - 1,000	3,269	3,155	3,155	3,161	3,206	3,200	3,199	3,197	3,397	3,365	3,384	3,399	3,413
11	1,001 - 2,000	3,241	3,057	3,062	3,071	3,119	3,126	3,126	3,123	3,404	3,448	3,435	3,452	3,468
12	2,001 - 5,000	1,204	1,205	1,214	1,214	1,208	1,210	1,216	1,215	1,291	1,194	1,161	1,159	1,166
13	5,001 - 10,000	273	260	262	262	263	262	263	262	287	262	296	295	296
14	10,001 - 30,000	25	22	22	22	22	22	22	23	24	19	32	33	33
15	> 30,000	3	3	3	3	3	3	3	3	3	2	2	2	2
16	Total Commercial	22,943	22,939	22,971	23,010	23,027	22,992	22,949	22,858	22,784	22,788	22,856	23,005	23,141
17														
18	Indust. Firm 0 - 300	126	128	127	127	127	127	127	126	122	126	126	127	127
19	301 - 1,000	54	53	53	53	55	54	55	55	54	54	54	53	53
20	1,001 - 2,000	51	50	50	50	50	50	49	49	54	52	53	53	53
21	2,001 - 5,000	20	19	19	18	19	18	18	18	19	22	22	22	22
22	5,001 - 10,000	6	8	8	8	8	8	8	8	8	3	3	3	3
23	10,001 - 30,000	4	4	4	4	4	4	3	3	3	4	4	4	4
24	> 30,000	2	2	2	2	2	2	2	2	2	1	1	1	1
25	Total Indust. Firm	263	264	263	262	265	263	262	261	262	262	263	263	263
26														
27	G & M 0 - 300	32	31	31	31	31	31	31	31	31	33	33	33	35
28	301 - 1,000	11	11	11	11	11	11	11	11	10	12	12	12	12
29	1,001 - 2,000	30	31	31	31	31	31	31	31	31	27	27	27	27
30	2,001 - 5,000	11	12	11	12	12	12	11	12	12	12	8	8	8
31	5,001 - 10,000	4	3	3	3	3	3	3	3	5	4	6	5	5
32	10,001 - 30,000	3	2	2	2	2	2	2	2	2	2	5	5	5
33	Total G & M	90	90	89	90	90	90	89	90	91	90	91	90	92
34														
35	Interdepart. 0 - 300	26	26	26	26	26	26	26	26	27	27	27	27	27
36	301 - 1,000	9	10	10	10	10	10	10	10	7	7	7	7	7
37	1,001 - 2,000	15	14	14	14	14	13	13	13	16	17	17	17	17
38	2,001 - 5,000	8	8	8	8	8	9	9	9	7	7	7	7	7
39	5,001 - 10,000	4	3	3	3	3	3	3	3	5	4	4	4	4
40	10,001 - 30,000	1	1	1	1	1	1	1	1	1	1	1	1	1
41	Total Interdepart.	62	62	62	62	62	62	62	62	63	63	63	63	63
42														
43	Total General Service	23,359	23,355	23,385	23,424	23,444	23,407	23,362	23,271	23,200	23,203	23,273	23,421	23,559
44														
45	**Core TBU: Utilities**													
46	10001 to 30000	1	1	1	1	1	1	1	1	1	1	1	1	1
47	> 30000	3	3	3	3	3	3	3	3	3	3	3	3	3
48		4	4	4	4	4	4	4	4	4	4	4	4	4

NorthWestern Energy

NorthWestern Energy
12 Months Ended December 2015
Natural Gas Utility

Number of Customers

Line No.	(A)	(B) Total	(C) January	(D) February	(E) March	(F) April	(G) May	(H) June	(I) July	(J) August	(K) September	(L) October	(M) November	(N) December
49	**Non-Core DBU: Firm**													
50	< 5000	48	48	48	48	48	48	48	48	48	48	48	48	48
51	5000 to 10000	101	102	102	102	102	101	101	101	101	101	101	101	100
52	10001 to 30000	56	56	56	56	56	56	56	56	56	56	56	57	57
53	> 30000	19	19	19	19	19	19	19	19	19	19	19	19	19
54		224	225	225	225	225	224	224	224	224	224	224	225	224
55														
56	**Non-Core DBU: Interruptible**													
57	< 5000	-	-	-	-	-	-	-	-	-	-	-	-	-
58	5000 to 10000	-	-	-	-	-	-	-	-	-	-	-	-	-
59	10001 to 30000	-	-	-	-	-	-	-	-	-	-	-	-	-
60	> 30000	-	-	-	-	-	-	-	-	-	-	-	-	-
61		-	-	-	-	-	-	-	-	-	-	-	-	-
62														
63	**Non-Core TBU: Firm**													
64	5000 to 10000	2	2	2	2	2	2	2	2	2	2	2	2	2
65	10001 to 30000	6	6	6	6	6	6	6	6	6	6	6	6	6
66	> 30000	24	25	25	25	25	24	24	23	23	23	23	23	23
67		32	33	33	33	33	32	32	31	31	31	31	31	31
68														
69	**Non-Core TBU: Interruptible**													
70														
71	5000 to 10000	-	-	-	-	-	-	-	-	-	-	-	-	-
72	10001 to 30000	-	-	-	-	-	-	-	-	-	-	-	-	-
73	> 30000	-	-	-	-	-	-	-	-	-	-	-	-	-
74		-	-	-	-	-	-	-	-	-	-	-	-	-
75														
76	Total Core & Non-Core	189,690	189,089	189,235	189,481	189,639	189,646	189,572	189,345	189,206	189,388	189,907	190,611	191,159

NorthWestern Energy

NorthWestern Energy
Natural Gas Utility
12 Months Ended December 2015

Normalized Consumption
MDDQ's & Dekatherms

Line No.	(A)	(B) Units	(C) TOTAL	(D) January	(E) February	(F) March	(G) April	(H) May	(I) June	(J) July	(K) August	(L) September	(M) October	(N) November	(O) December
1	**Core - DBU**														
2	RESIDENTIAL:														
3	Residential	Dkt	12,452,351	2,292,829	1,757,930	1,836,755	1,149,661	786,143	519,184	244,926	243,320	305,635	490,227	978,937	1,846,803
4	Employee	Dkt	28,206	4,984	3,979	4,175	2,715	2,000	1,439	522	553	655	1,135	2,109	3,940
5	Subtotal		12,480,557	2,297,813	1,761,909	1,840,931	1,152,376	788,143	520,623	245,448	243,873	306,290	491,362	981,045	1,850,743
6															
7	GENERAL SERVICE:														
8	Commercial	Dkt	6,512,452	1,191,340	903,026	920,186	583,369	406,517	279,240	182,123	174,229	191,606	254,113	493,148	933,555
9	Industrial Firm	Dkt	160,252	25,541	33,062	23,520	12,573	9,104	6,018	4,749	4,769	5,959	6,329	10,681	17,947
10	G & M	Dkt	60,404	11,972	6,099	8,517	5,526	3,965	2,626	876	1,677	1,717	2,687	5,850	8,893
11	Interdepart.	Dkt	58,825	10,470	7,798	8,163	5,937	3,819	3,159	1,472	1,458	1,668	2,297	4,550	8,033
12	Total - Gen. Ser.		6,791,933	1,239,323	949,986	960,386	607,405	423,405	291,043	189,221	182,133	200,950	265,425	514,228	968,427
13															
14	Core Market (Residential & General Service)		19,272,490	3,537,135	2,711,895	2,801,316	1,759,781	1,211,548	811,666	434,669	426,006	507,240	756,788	1,495,274	2,819,171
15															
16	Core - S&TBU: Utilities	Dkt	233,901	35,344	42,850	40,243	23,934	15,433	17,377	3,969	3,751	3,846	6,852	12,197	28,105
17	Transmission	MDDQ	33,012	2,751	2,751	2,751	2,751	2,751	2,751	2,751	2,751	2,751	2,751	2,751	2,751
18	Storage	MDDQ	18,156	1,513	1,513	1,513	1,513	1,513	1,513	1,513	1,513	1,513	1,513	1,513	1,513
19															
20	**Total Core Market**	Dkt	19,506,391	3,572,479	2,754,745	2,841,560	1,783,715	1,226,981	829,043	438,638	429,757	511,087	763,640	1,507,471	2,847,276
21															
22															
23	**Non-Core Market**														
24															
25	DBU Firm Transportation														
26	Firm Reservation	MDDQ	256,833	21,501	21,433	21,433	21,433	21,367	21,367	21,367	21,367	21,367	21,391	21,415	21,392
27	Interruptible Commodity	Dkt	135,360	23,597	30,899	21,818	14,766	4,838	2,443	2,162	3,214	3,035	5,708	5,878	17,002
28															
29	TBU Firm Transportation														
30	Firm Reservation	MDDQ	1,214,639	98,529	98,461	98,461	98,461	98,395	98,395	98,140	103,140	108,140	108,164	108,188	98,165
31	Firm Transportation	Dkt	17,506,478	2,006,995	2,034,017	1,713,150	1,609,036	1,243,340	1,119,243	915,826	1,092,424	1,227,707	1,288,514	1,522,591	1,733,635
32	Interrup Transportation	Dkt	6,035,341	494,791	419,793	475,233	476,987	428,075	492,083	450,033	506,627	656,324	548,092	562,941	524,362
33															
34	TBU Firm Storage														
35	Withdrawal Reservation	MDDQ	548,885	48,582	48,535	48,535	48,535	50,919	43,519	43,345	43,345	43,345	43,359	43,381	43,485
36	Injection Commodity	Dkt	3,200,683	4,003	3,459	3,516	11,012	358,760	362,637	676,614	420,305	719,961	312,462	198,601	129,353
37	Withdrawal Commodity	Dkt	3,245,988	567,503	1,200,183	805,799	400,267	7,320	658	506	32,977	545	527	750	228,953
38	Storage Capacity	Dkt	34,774,851	3,579,907	2,383,183	1,670,900	1,221,645	1,573,085	1,935,064	2,727,476	3,114,804	3,834,220	4,146,155	4,344,006	4,244,406
39															
40	Total Montana	Dkt	43,183,570	6,097,862	5,239,454	5,051,761	3,884,504	2,903,234	2,442,812	1,806,659	2,032,022	2,398,153	2,605,954	3,598,881	5,122,275

NorthWestern Energy

NorthWestern Energy
Natural Gas Utility
12 Months Ended December 2015
Miscellaneous & Other Operating Revenues

Normalized - Test Year

Line No.		Total	January	February	March	April	May	June	July	August	September	October	November	December
1	**Miscellaneous**													
2	492100 Utility Oil Sales	562,430	32,637	46,891	30,580	87,559	40,295	23,105	93,654	36,766	52,941	36,405	56,216	25,382
3	492200 Utility Liquid Sal	32,075	12,564	0	7,185	(30,386)	6,035	0	0	0	0	0	36,677	0
4	469410 NG Rents - Land	1,000	0	0	0	800	0	0	0	0	0	0	200	0
5	469580 NG Other Low Inc D	0	0	0	0	0	0	0	0	0	0	0	0	0
6	469610 NG Other Rev-Misc	7,840	171	171	171	171	5,510	171	171	171	171	171	611	180
7	469620 NG Other Rev-Mat S	10,175	0	2,875	432	0	120	227	419	1,545	823	341	1,822	1,573
8														
9	Total	613,520	45,372	49,936	38,367	58,144	51,959	23,503	94,243	38,482	53,936	36,917	95,526	27,134

NorthWestern Energy
Natural Gas Utility
Derivation of Proposed Tariff Rates

NorthWestern Energy

Line No.	(A)	(B) Docket No. D2015.10.81 Order No. 7451a Without Tax Deferred	(C) 6.4396% Uniform % Increase	(D) Proposed Rates
1	**Core Sales Service:**			
2	**Residential Natural Gas Service**			
3	D-RG-1 Rate Schedule			
4	Monthly Service Charge per Meter	$ 7.29	$ 0.47	$ 7.75
5	Commodity Charges:			
6	Distribution	$ 2.098629	$ 0.135144	$ 2.233773
7	Transmission	$ 1.242724	$ 0.080027	$ 1.322751
8	Storage	$ 0.378218	$ 0.024356	$ 0.402574
9	Total Commodity Charge	$ 3.719571		$ 3.959098
10				
11				
12	**General Natural Gas Service**			
13	Monthly Service Charge per Meter			
14	0 to 300	$ 18.94	$ 1.22	$ 20.15
15	301 to 1,000	$ 24.99	$ 1.61	$ 26.60
16	1,001 to 2,000	$ 40.26	$ 2.59	$ 42.85
17	2,001 to 5,000	$ 67.59	$ 4.35	$ 71.95
18	5,001 to 10,000	$ 83.05	$ 5.35	$ 88.40
19	10,001 to 30,000	$ 131.25	$ 8.45	$ 139.75
20	> 30,000	$ 159.48	$ 10.27	$ 169.80
21	Commodity Charges:			
22	Distribution	$ 2.028941	$ 0.130657	$ 2.159598
23	Transmission	$ 1.201183	$ 0.077352	$ 1.278535
24	Storage	$ 0.364751	$ 0.023489	$ 0.388240
25	Total Commodity Charge	$ 3.594875		$ 3.826373
26				
27	**Firm Utility Gas Contract Service**			
28	Monthly Service Charge per Meter			
29	10,001 to 30,000	$ 127.78	$ 8.23	$ 136.05
30	> 30,000	$ 329.40	$ 21.21	$ 350.70
31				
32	Transmission Charges:			
33	Reservation Rate (MDDQ)	$ 6.220535	$ 0.400581	$ 6.621116
34	Transmission Commodity Rate (Dkt)	$ 0.074147	$ 0.004775	$ 0.078922
35				
36	Storage Charges:			
37	Reservation Rate (MDDQ)	$ 4.947281	$ 0.318588	$ 5.265869
38	Storage Commodity Rate (Dkt)	$ 0.017897	$ 0.001153	$ 0.019050

NorthWestern Energy
Natural Gas Utility
Derivation of Proposed Tariff Rates

NorthWestern Energy

Line No.	(A)	(B) Docket No. D2015.10.81 Order No. 7451a Without Tax Deferred	(C) 6.4396% Uniform % Increase	(D) Proposed Rates
1	**Noncore: Transportation Service**			
2	Monthly Service Charge per Meter			
3	Distribution Level Meter Charges:			
4	2,000 to 5,000	$ 122.34	$ 7.88	$ 130.25
5	5,001 to 10,000	$ 139.80	$ 9.00	$ 148.85
6	10,001 to 30,000	$ 192.19	$ 12.38	$ 204.60
7	> 30,000	$ 223.22	$ 14.37	$ 237.65
8				
9	Transmission Level Meter Charges:			
10	5,001 to 10,000	$ 119.71	$ 7.71	$ 127.45
11	10,001 to 30,000	$ 172.08	$ 11.08	$ 183.20
12	> 30,000	$ 381.83	$ 24.59	$ 406.50
13				
14	**Firm Distribution**			
15	D-FTG-1 Rate Schedule			
16	Monthly Reservation Rate/Trans. MDDQ	$ 7.739992	$ 0.498428	$ 8.238420
17				
18	**Interruptible Distribution**			
19	D-ITG-1 Rate Schedule			
20	Commodity Charge - Maximum	$ 0.254495	$ 0.016389	$ 0.270884
21	Commodity Charge - Minimum	$ 0.017935		$ 0.017935
22				
23	**Firm Transmission**			
24	T-FTG-1 Rate Schedule			
25	Reservation Charge	$ 9.784615	$ 0.630095	$ 10.414710
26	Commodity Charge - Maximum	$ 0.074147	$ 0.004775	$ 0.078922
27	Commodity Charge - Minimum	$ 0.017935		$ 0.017935
28				
29	**Interruptible Transmission**			
30	T-ITG-1 Rate Schedule			
31	Commodity Charge - Maximum	$ 0.395798	$ 0.025488	$ 0.421286
32	Commodity Charge - Minimum	$ 0.017935		$ 0.017935
33				
34	**Firm Storage**			
35	T-FSG-1 Rate Schedule			
36	Withdrawal Reservation Charge	$ 4.675642	$ 0.301095	$ 4.976737
37	Capacity Commodity Charge	$ 0.022955	$ 0.001478	$ 0.024433
38	Injection Commodity Charge	$ 0.024163	$ 0.001556	$ 0.025719
39	Withdrawal Commodity Charge	$ 0.024163	$ 0.001556	$ 0.025719

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**NorthWestern Energy**																	
2	**Natural Gas Utility Production Assets**																	
3	**12-Months Ended 2015**																	
4				Test Period Revenues								Revenues @ Uniform Design Rates						
5																		
6						Bear Paw		South Bear Paw						Bear Paw		South Bear Paw		
7				Battle Creek		(NFR)		Devon		Total		Battle Creek		(NFR)		Devon		Total
8		Fixed Rates		$ 0.1237		$ 0.1700		$ 0.7823				$ 0.1244		$ 0.2492		$ 0.8867		
9																		
10	**Core - DBU**	Market (Dkt)																
11	RESIDENTIAL:																	
12	Residential	12,429,997		$ 1,537,591		$ 2,113,100		$ 9,723,987		$ 13,374,677		$ 1,546,300		$ 3,097,804		$ 11,021,708		$ 15,665,812
13	Employee	28,206		2,617		3,596		16,549		22,763		2,632		5,272		18,758		26,662
14	Subtotal	12,458,204		$ 1,540,208		$ 2,116,696		$ 9,740,536		$ 13,397,440		$ 1,548,931		$ 3,103,076		$ 11,040,466		$ 15,692,473
15																		
16	GENERAL SERVICE:																	
17	Commercial	6,139,815		$ 759,495		$ 1,043,769		$ 4,803,177		$ 6,606,441		$ 763,797		$ 1,530,165		$ 5,444,188		$ 7,738,150
18	Industrial Firm	157,400		19,470		26,758		123,134		169,362		19,581		39,227		139,567		198,374
19	G & M	58,440		7,229		9,935		45,717		62,881		7,270		14,564		51,819		73,653
20	Interdepart.	58,825		7,277		10,000		46,018		63,295		7,318		14,660		52,160		74,138
21	Total - Gen. Ser.	6,414,479		$ 793,471		$ 1,090,461		$ 5,018,047		$ 6,901,979		$ 797,965		$ 1,598,616		$ 5,687,733		$ 8,084,315
22																		
23	**Total Core - DBU**																	
24																		
25	**Utilities**	233,901		$ 28,934		$ 39,763		$ 182,981		$ 251,677		$ 29,097		$ 58,293		$ 207,401		$ 294,791
26																		
27	**Total Rate Schedule**	19,106,584		$ 2,362,612		$ 3,246,920		$ 14,941,564		$ 20,551,096		$ 2,375,994		$ 4,759,985		$ 16,935,600		$ 24,071,579
28																		
29																		
30		Account																
31	Other Utility Revenues:																	
32	Offsystem Sales	457110		$ 33,612		$ 30,366				$ 63,978		$ 33,612		$ 30,366		0		$ 63,978
33	Gathering Revenues	459000				644,388				644,388		0		644,388		0		644,388
34	Gathering Revenues	459100						971,873		971,873		0		0		971,873		971,873
35																		
36																		
37	Miscellaneous:																	
38	Miscellaneous Revenues	469610		$ 115,677		$ 354,292		$ 401,529		$ 871,498		$ 115,677		$ 354,292		$ 401,529		$ 871,498
39	Oil & Liquid Sales	492200						135,129		135,129		0		0		135,129		135,129
40																		
41	**Total**			$ 2,511,901		$ 4,275,966		$ 16,450,094		$ 23,237,961		$ 2,525,283		$ 5,789,031		$ 18,444,130		$ 26,758,444
42																		
43	**Proposed Revenue Change**			$ 13,382		$ 1,513,065		$ 1,994,036		$ 3,520,483								$ 3,520,483
44																		
45	**Percentage Rate Change from Test Period**			0.6%		46.6%		13.35%										
46																		
47	**Proposed Rates**			$ 0.1244		$ 0.2492		$ 0.8867										

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF JOHN M. SMITH

ON BEHALF OF NORTHWESTERN ENERGY

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Gas Supply Issues On and Around the NorthWestern System	8

Exhibits

NorthWestern's Natural Gas System Map	Exhibit__(JMS-1)
NorthWestern's September 2016 Tracker – Appendix C	Exhibit__(JMS-2)
AECO – 7A Price History	Exhibit__(JMS-3)

Witness Information

Q. Please state your name and business address.

A. I am John M. Smith and my business address is 11 East Park Street, Butte, Montana 59701.

Q. By whom and in what capacity are you employed?

A. I am employed by NorthWestern Energy ("NorthWestern") as Manager, Montana Gas Supply, in the Energy Supply Department.

Q. Please state your educational background and experience.

A. I attended Montana State University, graduating in 1979 with a Bachelor of Science degree in Business Management. Upon graduation, I went to work for The Montana Power Company ("MPC") in the Revenue Requirements Department. I have worked in various capacities in the electric and gas utilities and assumed the positions of Director of Gas Supply in May of 1988, Director of Resource Acquisition in May of 1996, and Manager of Strategic Sourcing in April 1998. I worked on the ConnectMPC project from April 1999 to April 2000, when I returned to the Energy Supply Division of MPC. In July 2002, after the acquisition of MPC by NorthWestern, my title was changed to Manager, Energy Supply. In August 2011, my title was changed to Manager, Montana Gas Operations as part of a reorganization of NorthWestern's Energy Supply Department. In late 2013, my title was changed to Manager, Montana Gas Supply.

1 **Q. What are your responsibilities as Manager, Montana Gas Supply?**

2 **A.** In this capacity, I am responsible for short- and long-term natural gas supply
3 planning and day-to-day natural gas portfolio management. These responsibilities
4 encompass NorthWestern's natural gas purchase contract negotiations and
5 administration in Montana. I also supervise the development of required data on
6 these topics for presentation to the Montana Public Service Commission ("MPSC"
7 or "Commission"). My position requires significant coordination with natural gas
8 suppliers and transportation services providers, as well as other departments of
9 NorthWestern, in relation to budget planning, natural gas purchase contracts,
10 operations and reliability, and other gas supply issues.

11

12 **Q. Have you previously filed testimony before this Commission?**

13 **A.** Yes. I have presented testimony addressing natural gas market and supply
14 matters in numerous natural gas cost tracking filings as well as other Commission
15 dockets involving natural gas supply issues.

16

17 **Purpose of Testimony**

18 **Q. What specific topics do you address in your testimony in this proceeding?**

19 **A.** My testimony provides an explanation of the following items:

20 1. Briefly detail NorthWestern's utility core customers and present the
21 NorthWestern Energy natural gas system map;
22 2. Discuss and compare the annual and peak natural gas supply requirement
23 on the NorthWestern Energy natural gas system; and

3. Discuss natural gas supply issues on and around the NorthWestern system.

My testimony supports the Prefiled Direct Testimony of John D. Hines.

NorthWestern's Customers and Supply Requirements

Q. Please briefly discuss NorthWestern's customer profile and the corresponding supply requirement.

A. NorthWestern currently provides natural gas to approximately 190,000 core customers, with an estimated annual load requirement of approximately 19,500,000 dekatherms ("Dkt"). The NorthWestern core customer load is highly seasonal and weather dependent in nature. The majority of the consumption (approximately 69% of the annual total or 13,500,000 Dkt) occurs during the winter period of November through March. NorthWestern's average daily supply requirement is 53,400 Dkt/day, while the lowest supply requirement is 15,200 Dkt/day in the summer. The winter average daily supply requirement is 89,400 Dkt/day. On the coldest day during the winter, (peak design day) NorthWestern's supply requirement for its customers can reach 230,000 Dkt.

Q. Please provide a copy of the NorthWestern natural gas transmission system map for reference in the discussion of the various supply components.

A. Please see Exhibit__(JMS-1) which is a recent version of NorthWestern's natural gas transmission pipeline system.

Annual and Peak Day Supply Requirements

Q. Please describe in detail, the annual volume and sources of supply to serve NorthWestern's core customers.

A. Please see Exhibit__(JMS-2) which is APPENDIX_C to the September 2016 monthly tracker filing. This spreadsheet lists the actual and forecast supply components to meet the supply requirements for the period July 1, 2016 through June 30, 2017. The column I want to focus on is the Dkt(000) column under the "GAS SUPPLY" heading. Please note that the first entry on line 14 labeled "NOVA" is only present to value the NOVA pipeline capacity and there is no active volumetric supply component associated with this entry.

1. Trans Canadian Pipeline (line 16) – This source point is labeled as "Carway" on the system map and is on the Montana / Alberta border west of Cut Bank. This point is the location where the off-system Canadian supply enters the NorthWestern system. The projected annual volume is 6,400,000 Dkt.
2. Havre Pipeline (line 18) – These multiple source points are located in the Havre area and are where NorthWestern records the third party gas that is purchased from its partners in the NorthWestern-owned production acquisitions. The projected annual volume from this source is 1,548,000 Dkt.
3. EnCana Pipeline (line 20) – This source point is labeled "Aden" on the system map and is located on the Montana / Alberta border east of Cut Bank. This point is where the Canadian gas purchased from Pine Cliff Resources enters the Montana gas transmission system. The projected annual volume from this source is 4,128,000 Dkt.

4. Colorado Interstate Pipeline (line 22) – This source point is labeled Grizzly on the system map and it is where NorthWestern's system is interconnected with the former Colorado Interstate Pipeline. This pipeline is now owned by Kinder Morgan. There are currently no projected annual volumes from this source.
5. NW Energy Owned Production (line 24) – This multiple point source designation is where NW Energy Owned Production is recorded on the spreadsheet. The projected annual volume from this source is 5,372,000 Dkt.
6. Intra-Montana Purchases (line 26) – This multiple point source designation is where all the direct purchases from independent producers in Montana are recorded in the spreadsheet. The projected annual volume from this source is 768,000 Dkt.
7. Storage (line 29) – This source point can be either an injection, in which case it will be reported as a negative supply input, or as a withdrawal which is currently reported as a positive supply component. The annual volume for this source is currently projected to be 1,337 Dkt. The reason that a withdrawal is currently forecast is that in April, May, and June of 2016 (previous tracker period) the price became very low (under $1.00/Dkt). NorthWestern injected additional volumes at the attractive prices and sped up the normal injection process. Injections in August, September, and October were correspondingly reduced to keep NorthWestern from over filling its available storage capacity of 8,900,000 Dkt. This causes the 2016/2017 tracker period to record a withdrawal. However, if the price next spring drops dramatically, NorthWestern will once again speed up the pace of injection and might end up with a net injection by

the end of June 2017. The next line "Storage Fuel Use" (line 30), denotes the amount of fuel that will be burned to inject the customer's gas into storage. The annual consumption projected for Storage Fuel Use is (83,000) Dkt.

The total projected annual supply for the 2016/2017 tracker period is 19,470,000 Dkt.

Q. Please briefly describe the Peak Day supply requirement and how NorthWestern is planning to meet that requirement this winter.

A. As previously mentioned, this winter's peak day supply requirement will be approximately 230,000 Dkt. NorthWestern will have 32,000 Dkt/day flowing on system including the Aden volume. There will be 82,500 Dkt/day of peak supply available at Carway. NorthWestern will also have 118,700 Dkt available from storage. These three sources of supply equal 233,200 Dkt.

Q. What is the projected volume that will be delivered from NorthWestern's Owned Production on a Peak Day?

A. NorthWestern will deliver, on a daily basis, just under, 15,000 Dkt this winter from the properties that have been acquired by NorthWestern.

1 **Gas Supply Issues On and Around the NorthWestern System**

2 **Q. Please discuss the declining availability of gas supply on and around the**
3 **NorthWestern system.**

4 **A.** The single most significant factor causing declining availability is price. The market
5 price for natural gas has dropped significantly in the last eight years since the
6 spring of 2008. This decline is the result of tremendous supplies of natural gas
7 being discovered and produced from shale formations due to significant increases
8 in the utilization of horizontal drilling. As the price has fallen, natural gas producers
9 on and near the NorthWestern system have chosen to reduce spending related to
10 the development of the traditional shallow gas reserves. This reduction in
11 development drilling has had a noticeable impact on NorthWestern's on-system
12 flowing supplies. The table below shows the following:

Year	Volume (Dkt/day)
2006	48,000
2008	43,400
2010	41,150
2012	40,600
2014	37,900
2016	31,500

20 The above figures for 2006 through 2012 were taken from NorthWestern's Biennial
21 Natural Gas Procurement Plans ("Plans") that listed the daily volume of "on-system
22 flowing gas" that is available all year. These volumes do not include seasonal or
23 peaking gas. The 2012 Plan, which was filed on December 14, 2012, in Docket

No. N2012.12.125 was the last Plan NorthWestern filed. The Commission comments on the 2012 Plan stated, in part:

> *"...Until further notice from the Commission that a comprehensive natural gas procurement plan is once again required, NorthWestern's natural gas procurement practices should be guided by the 2012 Plan and the Commission's comments in this Docket...."*

Q. Did NorthWestern's acquisition of natural gas production help to address the declining on-system supply issue?

A. It was a tremendous help. It made new supplies of gas available to NorthWestern that traditionally flowed off-system to Canada. Prior to NorthWestern's purchase of the Bear Paw (NFR) production, 100% of that gas flowed north through Havre Pipeline to reach its market. Prior to the purchase of the South Bear Paw (Devon) production, NorthWestern was purchasing 16,000 Dkt/day from Devon. After the South Bear Paw (Devon) purchase and once NorthWestern gained control of the operations of Havre Pipeline, NorthWestern stopped the flow north to Canada of roughly 4,000 Dkt/day. The gas from both of these acquisitions then remained on the system for the benefit of NorthWestern's customers.

Q. You mentioned the decline in prices since 2008. Please discuss in more detail the issue of market price volatility.

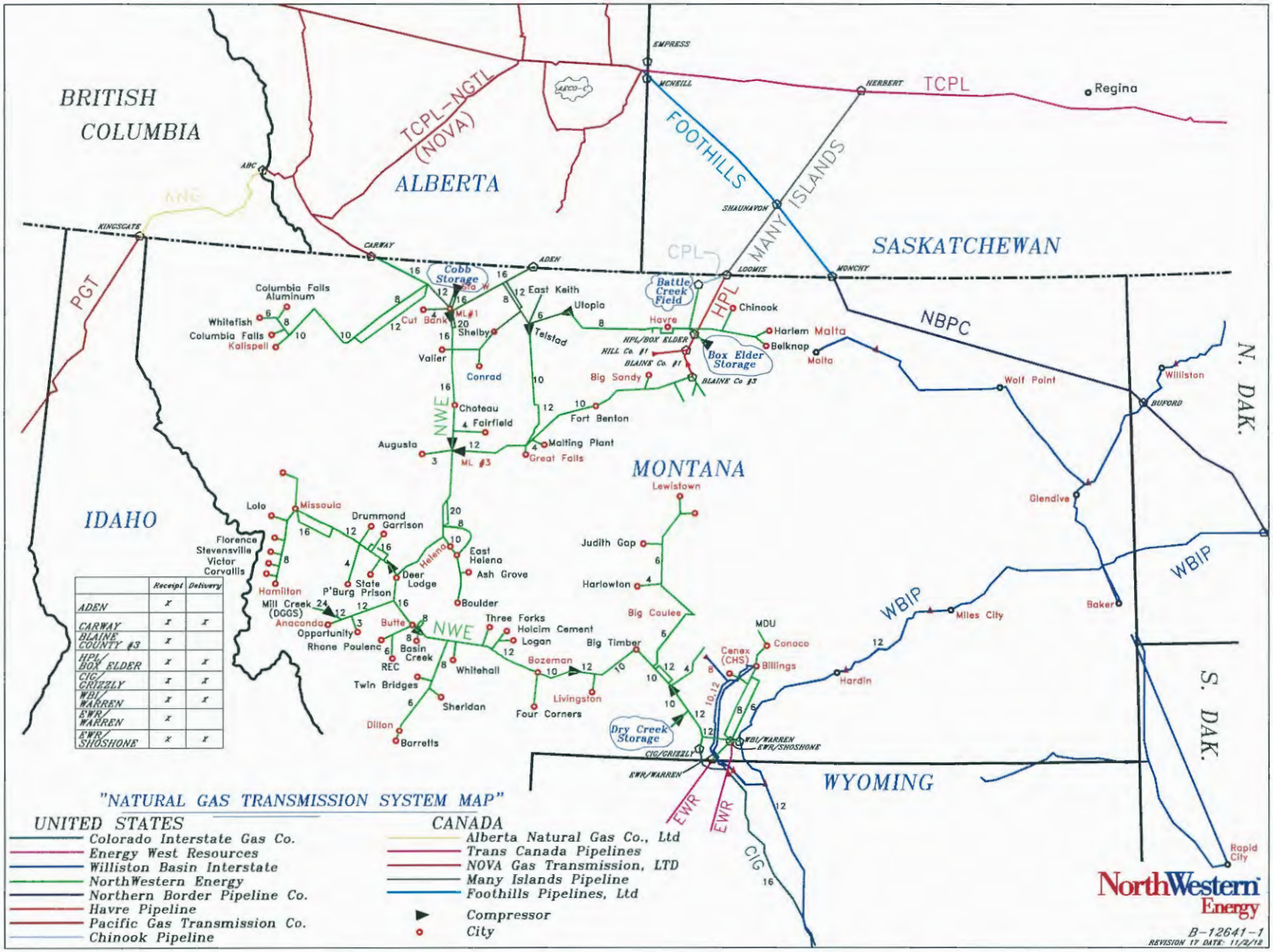
A. NorthWestern purchases significant volumes of gas in Montana and Alberta that are priced in relation to the AECO market.[1] NorthWestern maintains a data file that

[1] AECO is the historical name of a virtual trading hub on the NGX system, located in Alberta, Canada; AECO is now known as the Alberta Nova Inventory Transfer (AB-NIT) system operated by Trans Canada Pipeline Ltd.

1 shows historic AECO prices. The attached Exhibit__(JMS-3) is a plot of the
2 AECO-C 7A pricing dating back to January 2005.
3
4 **Q. What observations do you make from this exhibit?**
5 **A.** First, there has been significant price volatility since January 2005. Second, there
6 have been two significant price spikes in the past 10 years. The price during the
7 two spikes in 2006 and 2008 exceeded $10.00/Dkt. Third, the AECO market is
8 currently seeing relatively low natural gas prices compared to recent history.
9
10 **Q. Have the recent low natural gas prices had an impact on natural gas supplies**
11 **on the NorthWestern system?**
12 **A.** Yes. Earlier this year, the AECO market dipped below $1.00/Dkt. At that time,
13 small producers throughout NorthWestern's system were shutting their production
14 off because their operating costs were higher than the revenue they would receive
15 selling at the current price. That is a major factor for why the 2016 flowing gas
16 volume shown above is so much lower than the 2014 flowing gas number.
17
18 **Q. Has NorthWestern continued to produce its owned production?**
19 **A.** Yes, with minor exceptions. NorthWestem did turn off a small amount of its
20 production at the request of a few of its partners. NorthWestern's ability to control a
21 majority of this production has helped to ensure the reliability of on-system supply.
22 If NorthWestern was still purchasing a portion of these volumes from a third party
23 supplier, the volumes may have not been available.

1 **Q. Could NorthWestern simply have purchased the low cost gas in Canada and**
2 **had it delivered to the system?**
3 **A.** Yes, if pipeline capacity was available. TransCanada Pipelines ("TCPL") has fully
4 subscribed or sold firm capacity to the Alberta-Montana border point known as
5 Carway. This means that interruptible capacity (IT) would only be available when
6 the firm shippers are not using 100% of their capacity. NorthWestern currently
7 holds 66,000 Dkt of firm service (FT-D) to Carway. When prices were below
8 $1.00/Dkt, NorthWestern was flowing significant volumes of Canadian gas onto the
9 system to be placed in underground storage for use next winter. TCPL has had
10 maintenance-related delivery restrictions on firm service during the spring and
11 summer of 2016. This means that TCPL was actually lowering the volume of
12 available firm capacity to its various border points at that time.
13
14 **Q. Does NorthWestern's owned production help ensure reliability of supply?**
15 **A.** Definitely yes. On-system supply that can flow all winter for peaking and all
16 summer for storage injection when TCPL may be having maintenance issues that
17 restrict firm delivery service has become a valuable component of NorthWestern's
18 supply portfolio.
19
20 **Q. Does NorthWestern's owned production provide price stability for its**
21 **customers?**

1 **A.** Yes. The only variable cost components related to the owned production are gas
2 royalty payments and production-related taxes. These costs are included in the
3 monthly gas tracker because they vary each month with the market price for gas.
4
5 **Q. Has NorthWestern been able in recent years to negotiate any long-term**
6 **contracts?**
7 **A.** No. NorthWestern has attempted to negotiate contracts with its largest on-system
8 suppliers for durations of up to five years. The longest term that NorthWestern was
9 successful in attaining was two years with two separate suppliers.
10
11 **Q. Is NorthWestern's owned production a reliable, stably priced, long-term**
12 **supply alternative for both peak and annual supply requirements?**
13 **A.** Yes, it is the best type of supply because NorthWestern operates the production
14 assets, which provides reliability.
15
16 **Q. Does this conclude your testimony?**
17 **A.** Yes, it does.



	Receipt	Delivery
ADEN	x	
CARWAY	x	x
BLAINE COUNTY #3	x	
HPL/ BOX ELDER	x	x
CIG/ GRIZZLY	x	x
WBI/ WARREN	x	x
EWR/ WARREN	x	
EWR/ SHOSHONE	x	x

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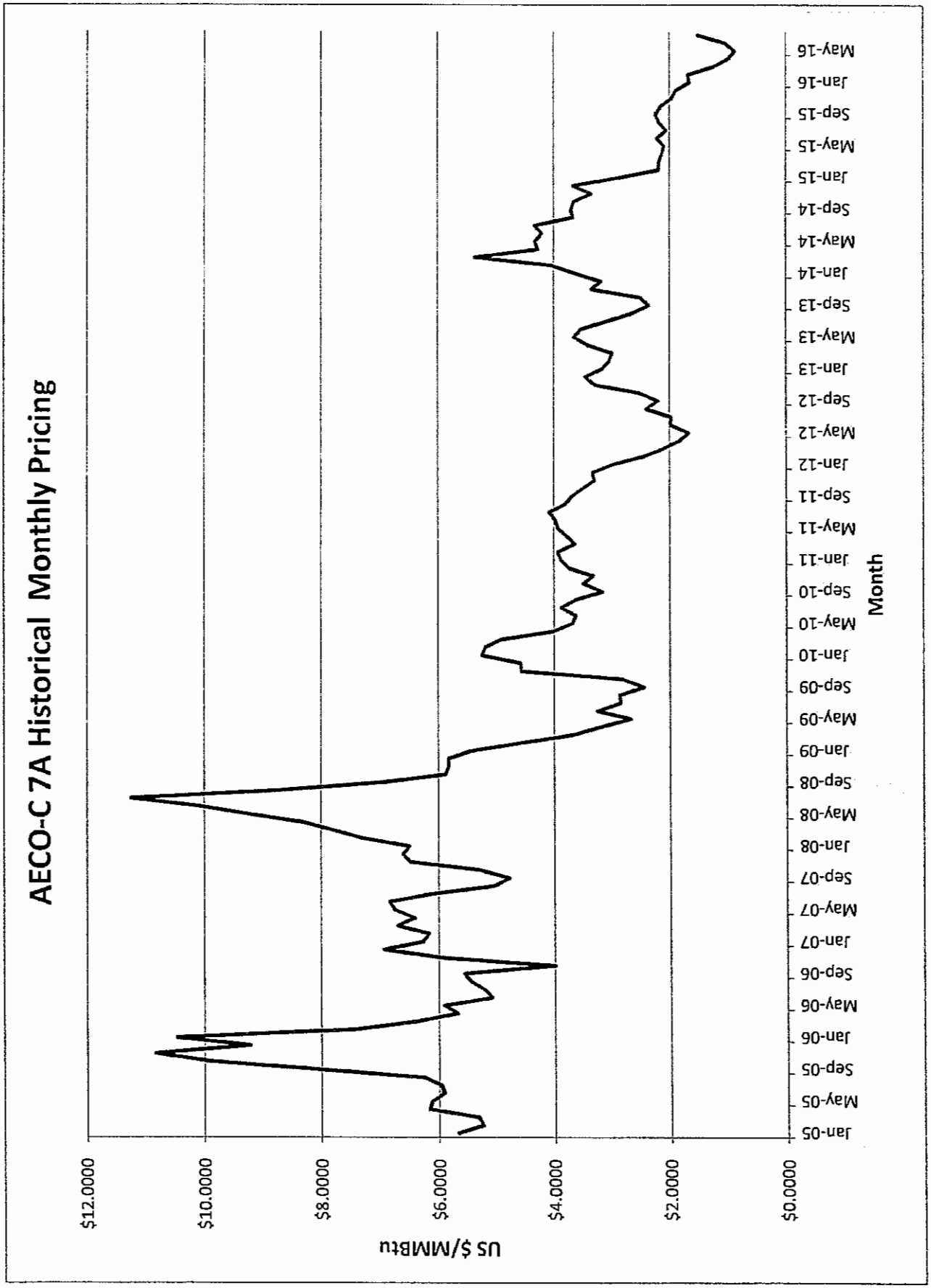
Exhibit__(JMS-1)
Page 1 of 1

NorthWestern Energy
SEPTEMBER 2016 MONTHLY
GAS COST ADJUSTMENT FILING

		Dkt (000)	$/Dkt	$ (000)
1	**CITY GATE REQUIREMENTS**			
2	DBU Sales Billed	18,825		
3	FUGC	234		
4	Subtotal Sales Volumes	19,059		
5	Core Fuel U&UAF	468		
6				
7	Grand Total HER	19,527		
8				
9				
10				
11	**GAS SUPPLY**			
12				
13				
14	NOVA	24,090	$ 0.130	$ 3,136
15				
16	Trans Canadian Pipeline	6,400	$ 1.830	$ 11,714
17				
18	Havre Pipeline	1,548	$ 1.983	$ 3,070
19				
20	EnCana Pipeline	4,128	$ 1.875	$ 7,740
21				
22	Colorado Interstate Pipeline	0	$ -	$ -
23				
24	NW Energy Owned Production	5,372	$ 0.512	$ 2,752
25				
26	Intra-Montana Purchases	768	$ 1.697	$ 1,303
27				
28				
29	Storage Net Withdrawal	1,337	NA	$ 140
30	Storage Fuel Use	(83)	NA	NA
31				
32	Total Gas Supply & Cost	19,470		$ 29,855
33				
34	Incremental Peaking Expense	0	$ -	$ -
35				
36	Working Gas Rate Base			$ 726
37	Deferred Account Interest			$ (59)
38	Administrative Costs			$ 362
39				
40	TOTAL GAS COST			$ 30,884
41	Battle Creek DSM Lost Revenue (negative revenue reported here as a cost)			$ -
42	DSM Lost Revenue (D,T, & S) (negative revenue reported here as a cost)			$ -
43	TOTAL GAS COST (Including DSM Lost Revenue)			$ 30,884
44				
45	September 2016 CORE Unit Gas Cost ($/Dkt)			$1.47850
46	Thermal Unit Rate ($/Therm)			$0.147850
47				
48	Battle Creek Revenue Requirement ($/Dkt)			$0.12370
49	Battle Creek Revenue Requirement ($/Therm)			$0.012370
50				
51	Bear Paw Revenue Requirement ($/Dkt)			$0.16420
52	Bear Paw Revenue Requirement ($/Therm)			$0.016420
53				
54	Devon Revenue Requirement ($/Dkt)			$0.77770
55	Devon Revenue Requirement ($/Therm)			$0.077770
56				
57	Total Combined Rate ($/Dkt)			$2.54410
58	Total Combined Rate ($/Therm)			$0.254410
59				
60	Previous Month's Total Unit Gas Cost ($/Dkt)			$2.58670
61	Thermal Unit Rate ($/Therm)			$0.258670
62				
63	Monthly Total Rate Change ($/Dkt)			($0.042600)
64	Monthly Total Rate Change ($/Therm)			($0.004260)


AECO-C 7A Historical Monthly Pricing
US $/MMBtu
$12.0000
$10.0000
$8.0000
$6.0000
$4.0000
$2.0000
$0.0000
Month
Jan-05
May-05
Sep-05
Jan-06
May-06
Sep-06
Jan-07
May-07
Sep-07
Jan-08
May-08
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Jan-09
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May-16

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF BLEAU J. LAFAVE

ON BEHALF OF NORTHWESTERN ENERGY

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Witness Information

Q. Please state your name and business address.

A. My name is Bleau J. LaFave. My business address is 3010 West 69th Street, Sioux Falls, South Dakota 57108.

Q. By whom are you employed and in what capacity?

A. I joined NorthWestern Energy ("NorthWestern") in July 1994 as Project Engineer, where I was responsible for the design, construction, and customer connections for natural gas expansion in South Dakota. My current position is Director Long Term Resources. My responsibilities include overseeing the long-term supply growth strategies for NorthWestern, including large project development and acquisitions.

Q. Please summarize your educational and employment experiences.

A. I earned a Bachelor of Science degree in Mechanical Engineering from the South Dakota School of Mines and Technology in 1994. After completing my degree, I was employed by NorthWestern Public Service as a Project Engineer. Working for NorthWestern, I have held several positions, including Operations Engineer, Huron Area Engineer, Aberdeen Area Engineer, Maintenance Process Leader, Support Services Process Leader, Corporate Procurement Manager, Director of Utility Services, Director of Large Project Development, Director South Dakota/ Nebraska Supply Planning and Development, Director Long Term Resources, and

1 Vice President of Operations for NorthWestern Services Corporation, a
2 former subsidiary of NorthWestern Public Service Company. During this
3 time, I served in many operations and administration functions with a
4 focus on operations management, procurement, logistics, contracts, fleet,
5 facilities, utility engineering, measurement, project development, supply
6 development, planning, acquisitions, and customer service.
7
8 **Purpose of Testimony**
9 **Q. What is the purpose of your testimony in this docket?**
10 **A.** The purpose of this testimony is to describe the evaluation process, the
11 acquisition process, and the benefit to customers for each of
12 NorthWestern's natural gas production asset acquisitions.
13
14 **Natural Gas Acquisitions**
15 **Q. Describe NorthWestern's representations and the Montana Public**
16 **Service Commission's ("Commission") comments regarding natural**
17 **gas acquisitions in NorthWestern's 2012 Natural Gas Supply**
18 **Procurement Plan ("2012 Plan") filed under Docket No. N2012.12.125.**
19 **A.** In its 2012 Plan, NorthWestern provided a detailed description of five
20 overarching components of its process for reviewing and acquiring natural
21 gas production resources: (1) Acquisition Properties Criteria, (2) Utilization
22 of Natural Gas Tracker as Interim Cost Recovery Method, (3) Analytical
23 Evaluation Approach (Financial Modeling), (4) Volume of Owned Natural

1 Gas Production (Bcf), and (5) Natural Gas Production Resource
2 Acquisition Thresholds to Serve Retail Customers. In its comments on the
3 2012 plan, the Commission stated, "The Commission supports the
4 volumes of owned natural gas production assets within the parameters
5 outlined in Plan", "The Commission expects NWE to purchase natural gas
6 following the concepts contained in the 2012 Plan", and "If NWE adheres
7 to and executes its procurement plan, taking into account the need to
8 remain flexible in its procurement approach, and is able to demonstrate to
9 the PSC's satisfaction that it has done so, then there should be no reason
10 for the PSC to make an imprudence finding." In its comment, the
11 Commission eliminated its requirement for NorthWestern to file biennial
12 natural gas procurement plans. The Commission stated, "Until further
13 notice from the Commission that a comprehensive natural gas
14 procurement plan is once again required, NorthWestern's natural gas
15 procurement practices should be guided by the 2012 Plan and the
16 Commission's comments in this Docket." Because the parameters
17 identified above are still controlling, I discuss each of them in detail.
18
19 **Q. Please discuss NorthWestern's Acquisition Properties Criteria**
20 **parameter.**
21 **A.** NorthWestern will pursue, evaluate, and purchase natural gas properties
22 that are strategically located to its system, meaning in close geographic
23 proximity to the markets served by NorthWestern. This includes natural

gas reserves that have traditionally been relied upon to supply natural gas customers that are directly connected to NorthWestern's natural gas transmission pipeline, or that are easily transported to NorthWestern's natural gas transmission pipelines via available third-party transport capacity at economical rates. These properties provide a long-term available and reliable supply of natural gas from previously developed proven natural gas production resources, which satisfy the following general criteria and/or characteristics:

A. Natural Gas Producing Properties that are located within these areas:

   i. Montana, Alberta, and British Columbia if properties are physically connected to the existing NorthWestern natural gas transmission system or if they could be connected with the installation of new natural gas gathering or transmission pipelines, to the extent it would be economically feasible; and

   ii. Montana, North Dakota, Wyoming, the Rockies, and Canada, realizing that the purchase of properties in these areas may require gas swaps or transportation agreements with other entities.

B. Properties with the following characteristics:

   i. At least 80% of the gas reserves' value in the proved producing category;

   ii. At least 80% of the gas reserves' value attributed to natural gas;

   iii. Well-established, mature production history of greater than 5 years; and

iv. At least 15 years of remaining estimated production life.

NorthWestern will consider acting as the operator in acquisitions where NorthWestern has majority interest and the expertise exists, but will also consider purchases in which another entity operates the properties.

Q, Discuss NorthWestern's Utilization of the Natural Gas Tracker as an Interim Cost Recovery Method parameter.

A. NorthWestern is utilizing a bridging concept for cost recovery of its Bear Paw (NFR) and South Bear Paw (Devon) acquisitions whereby the revenue requirement of the purchase is included in the Monthly Natural Gas Tracker Filings and NorthWestern is allowed to recover these costs on an interim basis until a revenue requirement filing can be made and processed in the future as described in the Prefiled Direct Testimony of Patrick R. Corcoran ("Corcoran Direct Testimony"). This same method was used for the Battle Creek acquisition. As described in the Corcoran Direct Testimony, without use of the bridge rates it is doubtful NorthWestern would have even been able to acquire these assets.

Q. Discuss NorthWestern's Analytical Evaluation Approach (Financial Modeling) parameter.

A. The Financial Modeling, as described in the Prefiled Direct Testimony of Travis E. Meyer ("Meyer Direct Testimony"), establishes a proposed

purchase price guided by the net present values ("NPVs"), in total dollars, of (1) the estimated future stream of annual revenue requirements of the purchased and rate-based natural gas reserves, given the proposed purchase price, expected operating costs and taxes, and the projected annual depletion rate of the particular property being evaluated; (2) the purchase of the equivalent amount (both timing and volume) of natural gas at the current annual natural gas market price forecast; and (3) the valuation of any other attributes of material value, which may also factor into a determination of the ultimate bid. Natural gas production resource acquisitions will only be considered when:

(1) the NPV of the estimated future stream of annual revenue requirements for the entire estimated useful life is less than the NPV of the estimated future stream of purchased natural gas costs at then-current natural gas market prices;

(2) the estimated production or volume weighted 20-year levelized unit revenue requirement of the owned reserves is less than the 20-year levelized natural gas market price, based on the natural gas market price forecast at the time of bidding; and

(3) the estimated future cost of service of the natural gas production resource, in dollars per Dekatherm ("Dkt"), is approximately equal to or less than the estimated future natural gas market price, in dollars per Dkt, based on the natural gas market price forecast at the time of

bidding, within three to five years of the acquisition, as specified in the table below.

Natural Gas Utility Acquisition Thresholds to Serve Retail Customers			
20 Year Levelized Unit Revenue Requirement	Future Unit Revenue Requirement/Market Price Crossover – In Years	Percent of Natural Gas Volume	Natural Gas Utility Annual Bcf Levels
Less than $4.00	5 or Less	75%	15.0
$4.00 to $5.00	4 or Less	50%	10.0
$5.00 to $6.00	3 or Less	25%	5.0

Q. Discuss NorthWestern's Volume of Owned Natural Gas Production (billion cubic feet ("Bcf")) parameter.

A. NorthWestern's natural gas acquisitions are divided into the following two categories:

(1) Strategic natural gas acquisitions of up to 20 Bcf of the natural gas required on an annual basis to serve NorthWestern's Retail Natural Gas Customers' loads; and

(2) Natural gas acquisitions of up to 5 Bcf on an annual basis to be used by NorthWestern's existing Electric Utility natural gas-fired generation facilities.

Such volumes may be considered collectively as part of NorthWestern's natural gas acquisitions.

1 NorthWestern may use a pro rata allocation of natural gas production
2 resource acquisitions that will serve both its Retail Natural Gas Customers
3 and Electric Utility natural gas-fired generation. NorthWestern will
4 designate such an allocation at the time of signing a natural gas
5 production asset purchase agreement.
6
7 **Q. Discuss NorthWestern's Natural Gas Production Resource**
8 **Acquisition Thresholds to Serve Retail Customers parameter.**
9 **A.** Natural gas acquisitions will be subject to the specific thresholds shown in
10 the table above, based on the estimated future unit revenue requirements
11 of the production and the natural gas market price forecast at the time of
12 bidding. Additionally, these thresholds only apply to the associated
13 Natural Gas Production and any gathering/delivery assets. They do not
14 apply to any Natural Gas Transmission or Distribution Pipeline assets that
15 may be part of a purchase.
16
17 **Q. What natural gas acquisitions has NorthWestern completed?**
18 **A.** Following the Battle Creek Acquisition in 2010, NorthWestern has
19 completed several other acquisitions of natural gas production and natural
20 gas gathering systems. These acquisitions include Bear Paw (NFR),
21 South Bear Paw (Devon), Black Hills, and various smaller transactions. I
22 discuss these subsequent acquisitions of natural gas production and
23 natural gas gathering assets below.

1 **Bear Paw (NFR) Acquisition Overview and Process**

2 **Q. Please provide a brief description of the Bear Paw (NFR) asset**
3 **acquisition.**

4 **A.** In August 2012, NorthWestern entered into an agreement to purchase an
5 ownership interest in assets in the Bear Paw Basin from NFR Energy LLC
6 ("NFR") with an effective date of November 1, 2012 as described in the
7 Prefiled Direct Testimony of Patrick E. Callahan ("Callahan Direct
8 Testimony"). These assets are located in north central Montana. NFR
9 owned varying working and revenue interests in about 610 gas wells, one
10 water injection well, and nine oil wells. The purchase also included NFR's
11 75% membership interest in the Lodge Creek and Willow Creek gas
12 gathering systems with approximately 400 miles of pipelines, meter
13 houses, 18 compressor sites, and a dehydration station in Blaine,
14 Chouteau, Fergus, and Hill counties. This acquisition consisted of proved
15 producing natural gas reserves, proved producing oil reserves, and the
16 gathering systems. The total net volume of the proved and producing
17 natural gas reserves from this acquisition is estimated to be 13.4 Bcf. The
18 total agreed purchase price was $19.5 million subject to closing
19 adjustments.
20

21 **Q. Please discuss the process NorthWestern used in evaluating the**
22 **Bear Paw (NFR) asset.**

23 **A.** NorthWestern formed a team led by John Hines, Vice President of Supply,

1 to evaluate the Bear Paw (NFR) assets. This team performed financial
2 analyses and due diligence on the Bear Paw (NFR) assets, culminating in
3 a bid proposal. These analyses and due diligence activities are discussed
4 in the Prefiled Direct Testimony of Stephan R. Smith ("S. Smith Direct
5 Testimony") and in the Callahan and Meyer Direct Testimonies. Key to
6 NorthWestern's bidding effort was its disciplined approach toward value
7 and risk. NorthWestern maintained value for its customers by not
8 submitting a bid price that exceeded its then-current natural gas market
9 price forecast. NorthWestern also reduced risk to its customers by
10 bidding only on the proved producing reserves. Proved undeveloped
11 reserves volumes are inherently more difficult to accurately quantify.
12
13 **Q. Were you part of the team involved in this process and the Bear Paw**
14 **(NFR) acquisition?**
15 **A.** Yes.
16
17 **Q. Did the acquisition include any assets besides the natural gas**
18 **properties?**
19 **A.** Yes. As I described previously, this transaction also included ownership in
20 nine producing oil wells that NorthWestern valued at $2.7 million of the
21 $19.5 million total transaction. The total volume of proved and producing
22 reserves from the acquisition was estimated to be 136,000 barrels of oil. As
23 part of the offering, NFR required these oil reserves to be part of the

purchase transaction to allow NFR to discontinue all operations in Montana.

Q. What did NorthWestern do with the oil reserves?

A. NorthWestern sold the oil reserves and production effective January 1, 2013 to Behm Energy for $3.2 million subject to closing settlements as described in the Callahan Direct Testimony.

Q. What was the effect to customers of the purchase and sale of the oil reserves and production?

A. As described in the Prefiled Direct Testimony of Crystal D. Lail, the oil purchase and sale were netted out of rate base.

Q. How did the Bear Paw (NFR) resource meet NorthWestern's Acquisition Properties Criteria?

A. The Bear Paw (NFR) assets are located in Montana and are directly connected to the NorthWestern transmission system. One hundred percent of the gas reserves' value is in the proved and producing category. Eighty-six percent of the gas reserves' value was attributed to natural gas. The field has been producing for well over five years and will continue to produce well beyond 15 years.

Q. How did the Bear Paw (NFR) resource meet NorthWestern's Interim Cost Recovery parameter?

1 **A.** NorthWestern began recovering Bear Paw (NFR)'s estimated cost of
2 service on an interim basis in its November 2012 monthly natural gas
3 tracker. This process is similar to that NorthWestern employed for the
4 Battle Creek acquisition. NorthWestern is including an estimate of the
5 Bear Paw (NFR) annual revenue requirement as part of NorthWestern's
6 natural gas supply rates on an interim basis pending the outcome of this
7 filing. The Commission approved this approach in its comments on the
8 2010 Plan saying, "including the cost of the Battle Creek production in the
9 monthly gas tracker filings is an appropriate way for NWE to bridge
10 between the time of the acquisition and a future filing by the company to
11 include the production in rate base."
12
13 **Q. How did the Bear Paw (NFR) resource meet NorthWestern's Financial**
14 **Modeling parameter?**
15 **A.** As described in the Meyer Direct Testimony, the Bear Paw (NFR)
16 acquisition met the Modeling parameter in the following ways:

	NFR Acquisition	**Forward Market Purch.**
47 Year NPV of Cost	$30,060,739	$30,078,049
20 Year Levelized cost	$3.80 per Dkt	$3.83 per Dkt
Future Unit Rev. Req / Market Price Crossover		Under 2 Years

(1) The NPV of the revenue requirement was less than the NPV of the purchased natural gas costs;

(2) The Bear Paw (NFR) resource 20-year levelized unit revenue requirement value was less than the 20-year levelized unit market purchase value; and

(3) The forecasted crossover point was within 2 years.

Q. What basis was used to forecast the natural gas market price?

A. As described in the Meyer Direct Testimony, the natural gas market forecast was based on the forward price strip at AECO dated February 22, 2012 as reported in the Inter-Continental Exchange ("ICE"). Prices beyond March 2017 were determined by applying an annual escalation factor of 2% until 2031. This 20-year forecasting method is consistent with the forecasting methodology set forth in the 2012 Plan and in NorthWestern's 2011 Electricity Supply Resource Procurement Plan.

Q. What is NorthWestern's Total Volume parameter for the Bear Paw (NFR) resources?

A. NorthWestern purchased the Bear Paw (NFR) resource to serve its core customers' loads estimated at 20 Bcf per year.

1 **Q. How did the Bear Paw (NFR) resource meet NorthWestern's Resource**
2 **Acquisition Thresholds parameter?**
3 **A.** The Resource Acquisitions Threshold Parameter is a function of the Total
4 Volume parameter. With a levelized price of $3.80 per Dkt, the total
5 natural gas annual Bcf from owned resources must not exceed 75% of the
6 forecasted core customer load. Seventy-five percent of the forecasted 20
7 Bcf core customer Load is a threshold of 15 Bcf/year. The Bear Paw
8 (NFR) resource contributes a maximum of 1.6 Bcf per year. Prior to
9 acquiring the Bear Paw (NFR) resource, NorthWestern owned the Battle
10 Creek Field that provides 0.5 Bcf/year. The total owned resources after
11 the acquisition of the Bear Paw (NFR) resource is less than 2.1 Bcf/year,
12 which is less than 75% of the 20 Bcf/year customer usage or the 15
13 Bcf/year maximum.
14
15 **South Bear Paw (Devon) Acquisition Overview and Process**
16 **Q. Please provide a brief description of the South Bear Paw asset**
17 **acquisition.**
18 **A.** In May 2013, NorthWestern entered into an agreement to purchase
19 operating and non-operating natural production interests in the Bear Paw
20 Basin from Devon Energy Production Company, L.P. ("Devon") with an
21 effective date of January 1, 2013. These assets are located in north
22 central Montana. The purchase included interests in approximately 914
23 producing gas wells and associated gathering lines in Blaine, Chouteau,

and Hill Counties. The proven developed producing reserves purchased are estimated to be 63.0 Bcf. The total agreed purchase price was $62.6 million subject to closing adjustments.

Q. Please discuss the process NorthWestern used in evaluating the South Bear Paw (Devon) asset.

A. NorthWestern formed a team led by John Hines, Vice President of Supply, to evaluate the South Bear Paw (Devon) assets. This team performed financial analyses and due diligence on the South Bear Paw (Devon) assets, culminating in a bid proposal. These analyses and due diligence activities are discussed in the Callahan Direct Testimony, the Meyer Direct Testimony, and the S. Smith Direct Testimony. Key to NorthWestern's bidding effort was its disciplined approach toward value and risk. NorthWestern maintained value for its customers by not submitting a bid price that exceeded its then-current natural gas market price forecast. NorthWestern also reduced risk to its customers by bidding only on the proved producing reserves. Proved undeveloped reserves volumes are inherently more difficult to accurately quantify.

Q. Were you part of the team involved in this process and the South Bear Paw (Devon) acquisition?

A. Yes.

1 **Q. How did the South Bear Paw (Devon) resource meet NorthWestern's**
2 **Acquisition Properties Criteria?**
3 **A.** The South Bear Paw (Devon) assets are located in Montana and are
4 directly connected to the NorthWestern transmission system. One
5 hundred percent of the gas reserves' value is in the proved and producing
6 category. One hundred percent of the gas reserves' value is attributed to
7 natural gas. The field has been producing for well over five years and will
8 continue to produce well beyond 15 years.
9
10 **Q. How did the South Bear Paw (Devon) resource meet NorthWestern's**
11 **Interim Cost Recovery parameter?**
12 **A.** NorthWestern began recovering South Bear Paw (Devon)'s estimated
13 cost of service on an interim basis on December 1, 2013 in the monthly
14 natural gas tracker as generally described in Corcoran Direct Testimony.
15 This process is similar to that NorthWestern employed for the Battle Creek
16 Field and the Bear Paw (NFR) resource. NorthWestern is including an
17 estimate of the South Bear Paw (Devon) annual revenue requirement as
18 part of NorthWestern's natural gas supply rates on an interim basis
19 pending the outcome of this filing. The Commission approved this
20 approach in its comments on the 2010 Plan saying, "including the cost of
21 the Battle Creek production in the monthly gas tracker filings is an
22 appropriate way for NWE to bridge between the time of the acquisition
23 and a future filing by the company to include the production in rate base."

1 **Q. How did the South Bear Paw (Devon) resource meet NorthWestern's**
2 **Financial Modeling parameter?**
3 **A.** As described in the Meyer Direct Testimony, South Bear Paw (Devon)
4 acquisition met the Modeling parameter in the following ways:

	Devon Acquisition	**Forward Market Purch.**
31 Year NPV of Cost	$149,463,846	$151,102,653
20 Year Levelized cost	$4.10 per Dkt	$4.12 per Dkt
Future Unit Rev. Req / Market Price Crossover		Under 4 Years

5 (1) The NPV of the revenue requirement was less than the NPV of the
6 purchased natural gas costs;
7 (2) The South Bear Paw (Devon) resource 20-year levelized unit revenue
8 requirement value was less than the 20-year levelized unit market
9 purchase value; and
10 (3) The forecasted crossover point was within four years.
11
12 **Q. What basis was used to forecast the natural gas market price?**
13 **A.** As described in the Meyer Direct Testimony, the natural gas market
14 forecast was based on the forward price strip at AECO dated March 6,
15 2013 as reported in the ICE. Prices beyond December 2017 were
16 determined by applying an annual escalation factor of 2%. This 20-year

1 forecasting method is consistent with the forecasting methodology set
2 forth in the 2012 Plan and in NorthWestern's 2011 Electricity Supply
3 Resource Procurement Plan.
4
5 **Q. What is NorthWestern's Total Volume parameter for the South Bear**
6 **Paw (Devon) resources?**
7 **A.** NorthWestern purchased the South Bear Paw (Devon) resource to serve
8 its core customers' loads estimated at 20 Bcf per year.
9
10 **Q. How did the South Bear Paw (Devon) resource meet NorthWestern's**
11 **Resource Acquisition Thresholds parameter?**
12 **A.** The Resource Acquisitions Threshold Parameter is a function of the Total
13 Volume parameter. The 20-year levelized unit revenue requirement for
14 the South Bear Paw (Devon) resource is $4.10/Dkt. With a levelized price
15 of $4.10, the total natural gas annual Bcf from owned resources must not
16 exceed 50% of the forecasted core customer load. Fifty percent of the
17 forecasted 20 Bcf core customer load is a threshold of 10 Bcf/year. The
18 South Bear Paw (Devon) resource contributes a maximum of 5.5 Bcf per
19 year. Prior to acquiring the South Bear Paw (Devon) resource,
20 NorthWestern owned the Battle Creek and Bear Paw (NFR) Fields that
21 provide 1.7 Bcf/year. The total owned resources after the acquisition of
22 the South Bear Paw (Devon) resource is 7.2 Bcf/year, which is less than
23 50% of the 20 Bcf/year customer usage.

1 **Black Hills Acquisition Overview and Process**

2 **Q. Please provide a brief description of the Black Hills asset**
3 **acquisition.**

4 **A.** In December 2015, NorthWestern entered into an agreement to purchase
5 operating and non-operating natural production interests in the Bear Paw
6 Basin from Black Hills Exploration and Production, Inc. ("Black Hills E&P")
7 with an effective date of July 1, 2015. These assets are located in north
8 central Montana. The purchase included interests in approximately 263
9 producing gas wells, two oil wells, and the remaining interests in the
10 Lodge Creek and Willow Creek gathering systems in Blaine, Hill, Fergus,
11 and Toole Counties. The proved developed producing reserves
12 purchased are estimated to be 1.22 Bcf. The total agreed purchase price
13 was $1.375 million which included $500,000 for the natural gas reserves
14 and $875,000 for the membership interests of Lodge Creek and Willow
15 Creek.
16
17 **Q. Please discuss the process NorthWestern used in evaluating the**
18 **Black Hills asset.**

19 **A.** NorthWestern formed a team led by John Hines, Vice President of Supply,
20 to evaluate Black Hills E&P interests. This team performed financial
21 analyses and due diligence on the Black Hills assets, culminating in a bid
22 proposal. These analyses and due diligence activities are discussed in
23 the Callahan Direct Testimony and in the Prefiled Direct Testimony of

1 Thomas K. Hohn. Key to NorthWestern's bidding effort was its disciplined
2 approach toward value and risk. NorthWestern maintained value for its
3 customers by not submitting a bid price that exceeded its then-current
4 price forecast. NorthWestern also reduced risk to its customers by
5 bidding only on the proved producing reserves. Proved undeveloped
6 reserves volumes are inherently more difficult to accurately quantify.
7
8 **Q. Were you part of the team involved in this process and the Black**
9 **Hills E&P acquisition?**
10 **A.** Yes.
11
12 **Q. Did the acquisition include any assets besides the natural gas**
13 **properties?**
14 **A.** Yes. This purchase also included two oil wells and the remaining interests
15 in the Willow Creek and Lodge Creek gathering systems. As a result of the
16 transaction, NorthWestern became the owner of 100% interest in the Lodge
17 Creek and Willow Creek gathering systems.
18
19 **Q. What did NorthWestern do with the oil reserves?**
20 **A.** The reserves are included in the rate-based calculation and the sales are
21 credited back to customers.
22

1 **Q. How did the Black Hills resource meet NorthWestern's Acquisition**
2 **Properties Criteria?**
3 **A.** The Black Hills E&P assets are located in Montana and are directly
4 connected to the NorthWestern transmission system. One hundred
5 percent of the gas reserves' value is in the proved and producing
6 category. Eighty-eight percent of the gas reserves' value is attributed to
7 natural gas. The field has been producing for well over five years and will
8 continue to produce well beyond 15 years.
9
10 **Q. How did the Black Hills resource meet NorthWestern's Interim Cost**
11 **Recovery parameter?**
12 **A.** The costs are not currently recovered under the Interim Cost Recovery
13 parameter. However, these assets are included in rate base in this
14 general rate filing for the first time.
15
16 **Q. How did the Black Hills resource meet NorthWestern's Financial**
17 **Modeling parameter?**
18 **A.** Using the same model from the Bear Paw (NFR) and the South Bear Paw
19 (Devon) with updated resources forecasts, NorthWestern evaluated the
20 Black Hills resources. The model is included in the Callahan Direct
21 Testimony, Exhibit__(PEC-17).
22 (1) At the time of bidding, the NPV of the estimated future stream of
23 annual revenue requirements for the entire estimated useful life was
24 $1.99 million. At the same time, the NPV of the estimated future

stream of purchased natural gas costs was $2.074 million. The NPV of the revenue requirement was less than the NPV of the purchased natural gas costs.

(2) At the time of bidding, the estimated production weighted 20-year levelized unit revenue requirement of the Black Hills resource was $2.81 per Dkt. The estimated levelized unit market price, based on the natural gas market price forecast was $2.98/Dkt. The Black Hills resource 20-year levelized unit revenue requirement value was less than the 20-year levelized unit market purchase value.

(3) With a levelized price of $2.98/Dkt, the unit revenue requirement/market price crossover must be five years or less. The forecasted crossover point was within five years.

Q. What basis was used to forecast the natural gas market price?

A. The natural gas market forecast was based on the forward AECO price strip provided by Lands Energy Consulting dated July 6, 2015. Prices beyond July 2020 were determined by applying an annual escalation factor of 4.41%. This method is consistent with the forecasting methodology used in NorthWestern's 2015 Electricity Supply Resource Procurement Plan.

Q. What is NorthWestern's Total Volume parameter for the Black Hills resources?

1 **A.** NorthWestern purchased the Black Hills resource to serve its core
2 customers' loads estimated at 20 Bcf per year.
3
4 **Q. How did the Black Hills resource meet NorthWestern's Resource**
5 **Acquisition Thresholds parameter?**
6 **A.** The Resource Acquisitions Threshold Parameter is a function of the Total
7 Volume parameter. The 20-year levelized unit revenue requirement for
8 the Black Hills resource is $2.81/Dkt. With a levelized price of $2.81 per
9 Dkt, the total natural gas annual Bcf from owned resources must not
10 exceed 75% of the forecasted Retail Natural Gas Customer load.
11 Seventy-five percent of the forecasted 20 Bcf Load is a threshold of 15
12 Bcf/year. Based on 2015, the Black Hills resource contributes a maximum
13 of 0.18 Bcf per year. Prior to acquiring the Black Hills resource,
14 NorthWestern owned the Battle Creek, Bear Paw (NFR), and South Bear
15 Paw (Devon) Fields that provide 5.6 Bcf/year. The total owned resources
16 after the acquisition of the Black Hills resource is 5.8 Bcf/year, which is
17 less than 75% of the 20 Bcf/year customer usage.
18
19 **Various Royalty and Working Interest Acquisition Overview**
20 **Q. Has NorthWestern acquired additional royalty and working**
21 **interests?**
22 **A.** Yes. As described in the Callahan Direct Testimony and the Meyer Direct
23 Testimony, NorthWestern purchased additional royalty and working

interests from various parties located in the Battle Creek, Bear Paw, and South Bear Paw basins. Each transaction was evaluated using the same process and criteria as the larger transactions with the exception of the smallest transactions below $50. These transactions consisted of royalty and working interests in wells that were already part of NorthWestern's portfolio.

Q. How did the Acquired Royalty/Working Interest resources meet NorthWestern's Acquisition Properties Criteria?

A. Each transaction is located in Montana and is directly connected to the NorthWestern transmission system. One hundred percent of the gas reserves' value is in the proved and producing category. One hundred percent of the gas reserves' value is attributed to natural gas. The fields have been producing for well over 5 years and will continue to produce well beyond 15 years. Each transaction represents additional interest in wells in which NorthWestern held an interest prior to the transaction.

Q. How did the Acquired Royalty/Working Interest resources meet NorthWestern's Interim Cost Recovery parameter?

A. The costs are not currently recovered under the Interim Cost Recovery parameter. However, these assets are included in rate base in this general rate filing for the first time.

1 **Q. How did the Acquired Royalty/Working Interest resources meet**
2 **NorthWestern's Financial Modeling parameter?**
3 **A.** At the time that NorthWestern evaluated and made each purchase, the
4 NPV of the estimated future stream of annual revenue requirements for
5 the entire estimated useful life was compared to the NPV of the estimated
6 future stream of purchased natural gas costs. At the time of each
7 resource purchase, the estimated production weighted 20-year levelized
8 unit revenue requirement was compared with the estimated levelized unit
9 market price, based on the natural gas market price forecast. For both
10 tests, each of the resource values was less than the market purchase
11 value. Each resource met both the total NPV test and the 20-year
12 levelized unit price test. All transactions met the cross over requirements
13 based on the 20-year levelized cost.
14
15 The only exception to this analysis was for transactions of less than $50.
16 If the transaction analysis was less than $50, the purchase price for the
17 interests was set at $50 based on the cost to track and process payments
18 to the third party owner.
19
20 **Q. What basis was used to forecast the natural gas market price?**
21 **A.** The natural gas market forecast was based on the forward price strip at
22 AECO dated near the transaction date as reported in the ICE. Prices
23 beyond the forward strip were determined by applying either a simple

annual escalation factor of 2% or a simple annual escalation factor matching the nominal Natural Gas Spot Price at Henry Hub escalation rate from the most recently reported Energy Information Administration annual report. The escalation rate method would depend on the timing of the acquisition in relation to the method used in related NorthWestern planning cycles. These methods are consistent with the forecasting methodology used in the 2012 Plan and in NorthWestern's 2011 Electricity Supply Resource Procurement Plan, 2013 Electric Supply Resource Procurement Plan, and 2015 Electric Supply Resource Procurement Plan, respectively, for each transaction.

Q. How did the Acquired Royalty/Working Interest resources meet NorthWestern's Total Volume parameter?

A. The combined volume of these transactions was 0.411 Bcf, which does not significantly impact the Total Volume Requirement.

Q. How did the Acquired Royalty/Working Interest resources meet NorthWestern's Resource Acquisition Thresholds parameter?

A. These transactions were too small to significantly impact the Total Volume Requirement.

Summary

Q. Please summarize your testimony regarding these acquisitions and their fulfillment of the resource acquisition criteria.

A. The table below summarizes my testimony regarding how each of the four acquisitions met the criteria at the time of evaluation and purchase. For additional details on each transaction please see the Callahan Direct Testimony.

Resource	Agreement Date	Total Volume (BCF)	First Year Production (Million Dkt)	Est. Purchased 20 Year Levelized ($/Dkt)	Market Forecast 20 Year Levelized ($/Dkt)	Purchased NPV (Million)	Market Forecast NPV(Million)	Crossover	Percent of Usage
Bear Paw (NFR)	August 2012	13.767	1.6	$ 3.80	$ 3.83	$ 30.06	$ 30.08	5 or less	8%
Bear Paw South (Devon)	May 2013	64.4	5.5	$ 4.10	$ 4.12	$ 152.83	$ 154.84	4 or less	28%
Black Hills	Dec 2015	1.22	0.18	$ 2.81	$ 2.98	$ 1.99	$ 2.07	5 or less	1%
Various	Various	0.411	Various	Various	Various	Various	Various	5 or less	<1%

Q. Does this conclude your testimony?

A. Yes, it does.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF TRAVIS E. MEYER

ON BEHALF OF NORTHWESTERN ENERGY

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Exhibits

Bear Paw (NFR) Evaluation Model	Exhibit__(TEM-1)
South Bear Paw (Devon) Evaluation Model	Exhibit__(TEM-2)

Witness Information

Q. Please state your name and business address.

A. My name is Travis E. Meyer. My business address is 3010 West 69th Street, Sioux Falls, South Dakota 57108.

Q. By whom are you employed and in what capacity?

A. I am employed by NorthWestern Energy ("NorthWestern") as the Director of Investor Relations and Corporate Planning. In my Investor Relations role I am largely responsible for communicating the strategic direction of NorthWestern to its equity investor community within the confines of Regulation Fair Disclosure. My Corporate Planning duties include oversight of the five-year financial planning model and related analysis as well as analysis and evaluation of certain projects on a case-by-case basis.

Q. Please summarize your educational and employment history.

A. I earned a Bachelor of Science degree in Business Administration from North Dakota State University. I have spent most of my professional career employed by NorthWestern starting in November of 2002 as an analyst for a non-utility division (Blue Dot). I was then hired by the utility in September of 2003 as a Manager of Financial Planning and Analysis and promoted to my current director role in December of 2012.

1 Prior to joining NorthWestern, I was employed as a Financial Consultant for
2 Merrill Lynch from 2000 to 2002.
3
4 **Purpose of Testimony**
5 **Q. What is the purpose of your testimony?**
6 **A.** The purpose of my testimony is primarily to provide an explanation of the
7 evaluation models used and resulting revenue requirements utilized in the
8 acquisition process for the Bear Paw (NFR) and South Bear Paw (Devon)
9 natural gas production properties.
10
11 **Q. Was the evaluation process similar for the Bear Paw (NFR) and South**
12 **Bear Paw (Devon) properties?**
13 **A.** Yes, both properties were evaluated using the same methodology
14 NorthWestern used prior to purchasing our first natural gas production asset,
15 Battle Creek, which was approved for inclusion in rate base in November
16 2012 (Docket No. D2012.3.25 - Final Order No. 7210b).
17
18 **Q. What process or criteria did you utilize to inform your maximum**
19 **purchase price for the assets?**
20 **A.** The Model establishes a maximum purchase price guided by the net present
21 values ("NPVs"), in total dollars, of (1) the estimated future stream of annual
22 revenue requirements of the purchased and rate-based natural gas reserves,
23 given the proposed purchase price, expected operating costs and taxes, and

the projected annual depletion rate of the particular property being evaluated; (2) the purchase of the equivalent amount (both timing and volume) of natural gas at the current annual natural gas market price forecast; and (3) the valuation of any other attributes of material value, which may also factor into a determination of the ultimate bid.

Natural gas production resource acquisitions will only be considered when, based on the bid amount, the following criteria are met:

(1) The NPV of the estimated future stream of annual revenue requirements for the entire estimated useful life is less than the NPV of the estimated future stream of purchased natural gas costs at then-current natural gas market prices;

(2) The estimated production or volume weighted 20-year levelized unit revenue requirement of the owned reserves is less than the 20-year levelized natural gas market price, based on the natural gas market price forecast at the time of bidding; and

(3) Within three to five years of the acquisition, based on the natural gas market price forecast at the time of bidding, the estimated future cost of service of the natural gas production resource, in dollars per dekatherm ("Dkt"), is expected to be approximately equal to or less than the estimated future natural gas market price. This is known as the market price crossover, as specified in the table adapted from NorthWestern's 2012 Natural Gas Supply Procurement Plan ("2012 Plan") below.

20-Year Levelized Cost Per Unit (Dkt)	Future Unit Revenue Requirement / Market Price Crossover (Years)
Less than $4.00	5 or Less
$4.00 to $5.00	4 or Less
$5.00 to $6.00	3 or Less

1 **Q. Is this the same methodology described in your most recent biennial**
2 **supply plan?**
3 **A.** Yes. As stated above, this methodology is consistent with what was included
4 in our 2012 Plan, which was the last one we filed in Docket No.
5 N2012.12.125.
6
7 **Q. Did the Montana Public Service Commission ("Commission" or**
8 **"MPSC") comment or provide direction regarding acquiring natural gas**
9 **production assets and the proposed evaluation process?**
10 **A.** Yes, ¶ 32 of the May 22, 2013 Commission Comments on NorthWestern's
11 2012 Plan included the following:

12 *The Commission's view on NorthWestern's acquisition of*
13 *natural gas reserves or production is unchanged from its*
14 *comments on the 2010 Plan. Failure to examine the possibility*
15 *of purchasing reserves given the recent growth in natural gas*
16 *reserves in the United States and the resulting decline in natural*
17 *gas prices would not be prudent. Owning natural gas reserves,*
18 *or owning an interest in them, can result in benefits to*

ratepayers versus simply buying natural gas at market prices. In pursuing the acquisition of major natural gas reserves, NorthWestern must strive to find transactions which provide compelling customer benefit over buying natural gas at market prices. The main factors that NorthWestern needs to evaluate are volumes, price, and term. Given that a large amount of capital will be required to purchase significant natural gas reserves, the Commission notes that such a transaction will be best presented to the Commission in the form of a stipulated agreement concerning the acquisition between NorthWestern and MCC.

Q. Did NorthWestern file an updated biennial Supply Plan in 2014?

A. No, ¶ 36 of the May 22, 2013 Commission comments on NorthWestern Energy's Supply Plan also included the following:

There is no need for NorthWestern to continue the biennial filing of a comprehensive gas procurement plan. Until further notice from the Commission that a comprehensive natural gas procurement plan is once again required, NorthWestern's natural gas procurement practices should be guided by the 2012 Plan and the Commission's comments in this Docket.

Bear Paw (NFR) Evaluation

Q. Describe the timeframe and primary inputs utilized in the evaluation model for the Bear Paw (NFR) properties.

A. Timeframe of evaluation: January – February 2012.

Rate of Return: NorthWestern used debt rates and capital structure consistent with our then most recently authorized natural gas delivery rates of a 52% debt / 48% equity capital structure with a 5.76% cost of debt (Docket No. D2009.9.129, Order No. 7046i). However, instead of utilizing the 10.25%

return on equity as authorized in that same docket, we used an even more recent 10.00% return on equity authorized for the Spion Kop Wind Generation Project (Docket No. D2011.5.41, Order No. 7159l). The resulting rate of return ("ROR") was 7.80%.

Operating expenses / credits: NorthWestern utilized estimates provided by The Oil & Gas Asset Clearinghouse ("The Clearinghouse") to inform lease operating expense estimates. Gathering and transmission expenses were estimated to be $0.80 per Dkt of gas produced. Production taxes and royalties were estimated to average 10.26% of wellhead revenues. Well plugging and abandonment expense was assumed to be approximately $4,000 per well ($10,000 less 60% salvage value for equipment). Revenue credits, or reduction to expense, were included based upon the anticipated annual sales of oil byproducts and gathering and compression for third parties. Additional information regarding operating expenses is included in the Prefiled Direct Testimony of Patrick E. Callahan ("Callahan Direct Testimony").

Montana Consumer Counsel ("MCC") / MPSC Taxes: These taxes were estimated at 0.24% of the total revenue requirement.

Depletion and Depreciation expense: The natural gas and oil were depleted over the estimated 47-year remaining production life consistent with the

forecasted quantity extracted from the ground. The gathering lines were also depreciated on the same basis (i.e. prorated with the quantity of gas and oil extracted). Compressors, pipelines and other equipment were depreciated based upon 35 year straight-line depreciation for book purposes and 15 year Modified Accelerated Cost Recovery System ("MACRS") for tax purposes.

Income taxes: These taxes were based on a standard calculation using a 35% federal rate and 6.75% Montana state rate with the benefit of accelerated depreciation on state taxes flowing through and adjusting income tax expense.

Natural gas and oil production estimates: We utilized production estimates based upon information provided by The Clearinghouse. Additional information regarding production estimates is included in the Callahan Direct Testimony and in the Prefiled Direct Testimony of Stephan R. Smith ("S. Smith Direct Testimony").

Natural gas price forecasts: A February 22, 2012 AECO – 5 forward price curve was utilized to evaluate the economics of owned reserves as compared to market purchases. Additional information regarding the forward price curve is in the Prefiled Direct Testimony of Bleau J. LaFave ("LaFave Direct Testimony").

1 **Q. What were the results of this evaluation model?**

2 **A.** Using the inputs as discussed above, NorthWestern determined a purchase
3 price of $19.515 million or less would satisfy the three financial criteria
4 explained above. The evaluation model is included as Exhibit__(TEM-1), but
5 the specific results based upon our final $19.5 million indicative bid[1] were:

	NFR Acquisition	Forward Market Purch.
47 Year NPV of Cost	$30,060,739	$30,078,049
20 Year Levelized cost	$3.80 per Dkt	$3.83 per Dkt
Future Unit Rev. Req / Market Price Crossover		Under 2 Years

6 **South Bear Paw (Devon) Evaluation**

7 **Q. Describe the timeframe and primary inputs utilized in the evaluation**
8 **model for the South Bear Paw (Devon) properties.**

9 **A.** Timeframe: October 2012 – November 2013.

10

11 Rate of Return: NorthWestern used a capital structure and return on equity
12 consistent with our then most recently authorized natural gas delivery case
13 (Docket No. D2012.9.94, Order No. 7249e) of a 52.33% debt / 47.67% equity
14 capital structure and a 9.8% return on equity. We planned to finance the
15 transaction with a debt issuance at a rate of approximately 4.0% and utilized
16 this as our cost of debt. The resulting ROR was 6.76%.

[1] As discussed in the Callahan Direct Testimony, the final purchase price was adjusted to $19.2 million.

1 Operating expenses / credits: NorthWestern utilized the actual expense
2 experienced by Devon Energy Production Company L.P. in 2012 as a basis
3 for estimating operating, gathering, and transmission expenses and revenue
4 credits. Salary and labor expenses for 2012 were adjusted based upon
5 planned changes to headcount and compensation levels. All operating
6 expenses were adjusted annually based upon the number of operating wells,
7 and gathering and transmission expenses were based upon production
8 estimates. Well plugging and abandonment expense was assumed to be
9 approximately $4,000 per well ($10,000 less 60% salvage value for
10 equipment).
11
12 MCC / MPSC Taxes: These taxes were estimated at 0.24% of the total
13 revenue requirement.
14
15 Depletion and Depreciation expense: The natural gas was depleted over the
16 estimated 31-year remaining production life consistent with the quantity
17 extracted from the ground. The gathering lines were also depreciated on the
18 same basis (i.e. prorated with the quantity of gas and oil extracted).
19 Compressors, pipelines and other equipment were depreciated based upon
20 30 year straight-line depreciation for book and 15 year MACRS for tax
21 purposes.
22

1 Income taxes: These taxes were based on a standard calculation using a
2 35% federal rate and 6.75% Montana state rate with the benefit of
3 accelerated depreciation on state taxes flowing through and adjusting income
4 tax expense.
5
6 Natural gas estimates: NorthWestern utilized production estimates based
7 upon information provided by Consulting Petroleum Engineer, Stephan R.
8 Smith. Additional information regarding production estimates is included in
9 the S. Smith Direct Testimony.
10
11 Natural gas price forecasts: A March 6, 2013 AECO – 5 forward price curve
12 was utilized to evaluate the economics of owned reserves as compared to
13 market purchases. Additional information regarding the forward price curve
14 can be found in the LaFave Direct Testimony.
15
16 **Q. What were the results of this evaluation model?**
17 **A.** Using the inputs as discussed above, NorthWestern determined that a
18 purchase price of approximately $63.4 million or less would satisfy the three
19 financial criteria addressed above. This evaluation model is included as
20 Exhibit__(TEM-2) but the specific results based upon our $62.571 million
21 purchase price[2] were:
22

[2] $70,200,000 total purchase price, less $6,182,000 portion for Havre Pipeline Company, less $1,446,957 for wells excluded due to others exercising preferential rights (Chippewa Cree Tribe).

	Devon Acquisition	Forward Market Purch.
31 Year NPV of Cost	$149,463,846	$151,102,653
20 Year Levelized cost	$4.10 per Dkt	$4.12 per Dkt
Future Unit Rev. Req / Market Price Crossover		Under 4 Years

1 **Other Small Reserve Acquisitions**

2 **Q. Has NorthWestern made any natural gas reserves acquisitions other**
3 **than the Bear Paw (NFR) and South Bear Paw (Devon) properties**
4 **described above?**

5 **A.** Yes, we have completed 28 other smaller acquisitions in the Bear Paw basin
6 totaling $0.656 million over the last three years. This total includes the
7 $0.500 million purchase of reserves from Black Hills Exploration and
8 Production, Inc.

9

10 **Q. Did you follow a similar methodology for the other smaller acquisitions?**

11 **A.** Yes, the evaluation models for the other smaller acquisitions were prepared
12 by Patrick E. Callahan, NorthWestern's Director Gas Growth & Storage, with
13 most of them using the same methodology. However, very small acquisitions
14 (i.e. several as small as $50 each) were made using a simplified process that
15 also considered the administrative savings of paying and servicing fewer
16 royalty owners. Additional information on these other smaller acquisitions is
17 included in the Callahan Direct Testimony.

18

1 **Q. Does this conclude your testimony?**

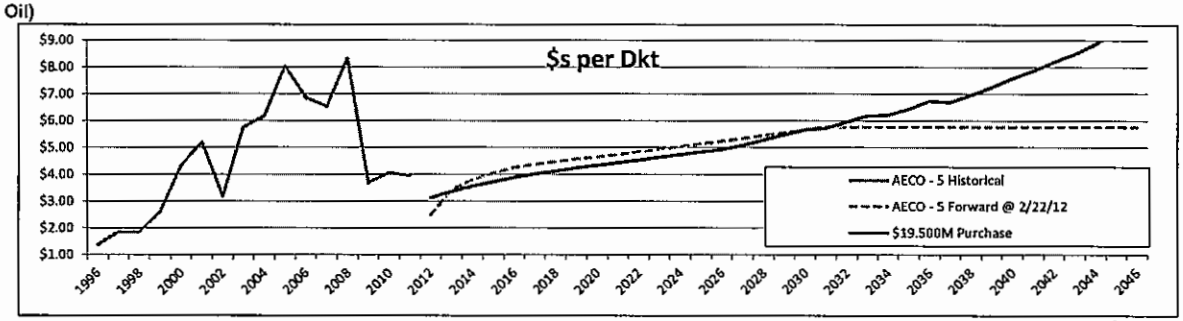
2 **A.** Yes, it does.

NorthWestern Energy
Preliminary natural gas acquisition analysis
Confidential and for management discussion only
February 23, 2012

NFR PDP Combined - + oil G&C - Smith 10% ROE

Scenario:	Total PDP (Nat Gas and Oil)
Bid (assuming price adjustment below)	$19,500
Sale of Oil Reserves	$0
Estimated Value of Probables	$0
Estimated strategic value of pipeline	$0
GST estimate (5% of $1M tangible non-petroleum assets)	$0
Total rate base estimate	$19,500

Earned ROE	10.00%
Cost of Debt	5.76%
Equity % of Cap Structure	48.00%
Weighted Average Cost of Capital (WACC)	7.80%



Purchase of Reserves	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2046
Average Rate Base ($000's)	18,494	16,611	14,979	13,561	12,311	11,196	10,194	9,288	8,460	7,699	6,999	6,354	5,757	5,205	324
Production (Bcf)	1.60	1.33	1.13	0.98	0.86	0.77	0.68	0.61	0.55	0.49	0.44	0.40	0.36	0.32	0.04
Estimated Revenue Requirement ($000's)	$5,011	$4,458	$4,032	$3,653	$3,344	$3,081	$2,804	$2,572	$2,371	$2,180	$2,006	$1,851	$1,696	$1,557	$360
Resulting Forward Prices ($/DKT)	$3.13	$3.36	$3.56	$3.73	$3.88	$4.01	$4.12	$4.23	$4.33	$4.43	$4.53	$4.64	$4.73	$4.82	$10.28
47 Year NPV of revenue requirement ($000's)	**$30,061**														
20 Yr Levelized Price	**$3.80**	**$2,886**	**759**												
35 Yr Levelized Price	**$3.87**	**$2,520**	**651**												

Procure at Forward Curve															
AECO - 5 Strip	$ 2.43	$ 3.37	$ 3.75	$ 3.98	$ 4.20	$ 4.33	$ 4.41	$ 4.50	$ 4.59	$ 4.69	$ 4.78	$ 4.88	$ 4.98	$ 5.08	$ 5.72
Revenue Requirement ($000's)	$ 3,892	$ 4,468	$ 4,242	$ 3,903	$ 3,616	$ 3,322	$ 3,001	$ 2,737	$ 2,513	$ 2,306	$ 2,118	$ 1,946	$ 1,786	$ 1,640	$ 200
47 Year NPV of revenue requirement ($000's)	**$30,078**	***Or***	***0.1%***	***greater than purchase option***											
20 Yr Levelized Price	**$3.83**	**$2,907**	**759**												
35 Yr Levelized Price	**$3.87**	**$2,522**	**651**												

Proved Producing

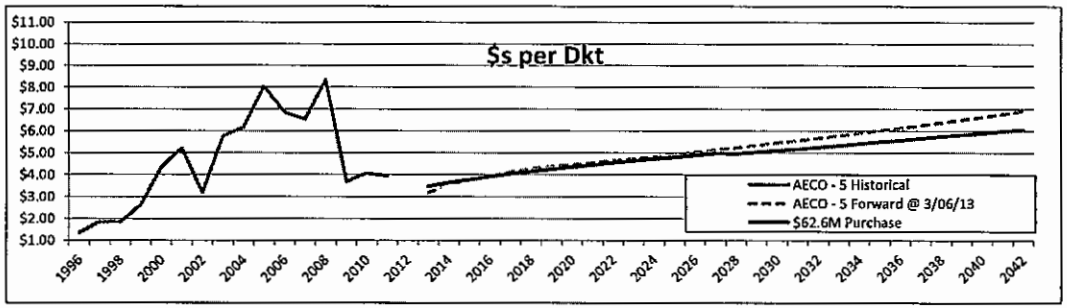
	Mdkt/yr (as provided)	Mdkt/yr	$/dkt Wellhead	$/dkt Wellhead	Gas Revenues $	G&C Oil Revenues	Operating Expense	Abandonment Costs	Royalties & Taxes (as provided)	Royalties & Taxes (calculated)	Net Revenues
2012	1,636	1,601	$ 1.65	$ 1.65	$ 2,641,650	$ 1,208,979	$ 618,703	$ -	$ 271,033	$ 271,033	$ 2,960,892
2013	1,348	1,326	$ 2.07	$ 2.07	$ 2,740,709	$ 1,010,134	$ 617,070	$ -	$ 281,197	$ 281,197	$ 2,852,576
2014	1,153	1,132	$ 2.28	$ 2.28	$ 2,584,130	$ 853,789	$ 609,420	$ 92,000	$ 265,132	$ 265,132	$ 2,471,367
2015	1,005	980	$ 2.43	$ 2.43	$ 2,381,400	$ 737,679	$ 588,239	$ 44,000	$ 244,332	$ 244,332	$ 2,242,508
2016	884	862	$ 2.56	$ 2.56	$ 2,208,530	$ 647,709	$ 573,684	$ 44,000	$ 226,595	$ 226,595	$ 2,011,960
2017	784	768	$ 2.71	$ 2.71	$ 2,077,670	$ 576,886	$ 558,955	$ 60,000	$ 213,169	$ 213,169	$ 1,822,432
2018	697	680	$ 2.86	$ 2.86	$ 1,946,908	$ 512,873	$ 513,953	$ 72,000	$ 199,753	$ 199,753	$ 1,674,075
2019	625	608	$ 3.03	$ 3.03	$ 1,840,720	$ 457,256	$ 477,827	$ 72,000	$ 188,858	$ 188,858	$ 1,559,291
2020	566	547	$ 3.21	$ 3.21	$ 1,755,214	$ 408,120	$ 447,485	$ 52,000	$ 180,085	$ 180,085	$ 1,483,763
2021	513	492	$ 3.38	$ 3.38	$ 1,663,108	$ 369,544	$ 419,070	$ 40,000	$ 170,635	$ 170,635	$ 1,402,947
2022	469	443	$ 3.54	$ 3.54	$ 1,567,777	$ 333,791	$ 392,459	$ 40,000	$ 160,854	$ 160,854	$ 1,308,255
2023	425	399	$ 3.69	$ 3.69	$ 1,473,587	$ 296,517	$ 367,538	$ 28,000	$ 151,190	$ 151,190	$ 1,223,376
2024	389	359	$ 3.85	$ 3.85	$ 1,380,463	$ 273,800	$ 344,199	$ 44,000	$ 141,635	$ 141,635	$ 1,124,428
2025	353	323	$ 3.85	$ 3.85	$ 1,242,032	$ 245,869	$ 322,342	$ 28,000	$ 127,432	$ 127,432	$ 1,010,126
2026	319	291	$ 3.85	$ 3.85	$ 1,118,982	$ 217,398	$ 301,874	$ 96,000	$ 114,808	$ 114,808	$ 823,699
2027	288	262	$ 3.85	$ 3.85	$ 1,007,469	$ 191,974	$ 282,705	$ 24,000	$ 103,366	$ 103,366	$ 789,371
2028	261	235	$ 3.85	$ 3.85	$ 903,646	$ 165,344	$ 264,753	$ 48,000	$ 92,714	$ 92,714	$ 663,523
2029	236	212	$ 3.85	$ 3.85	$ 815,204	$ 140,716	$ 247,941	$ -	$ 83,640	$ 83,640	$ 624,339
2030	213	191	$ 3.85	$ 3.85	$ 734,452	$ 117,952	$ 232,197	$ -	$ 75,355	$ 75,355	$ 544,852
2031	193	172	$ 3.85	$ 3.85	$ 661,392	$ 125,809	$ 217,452	$ 124,000	$ 67,859	$ 67,859	$ 377,890
2032	174	154	$ 3.85	$ 3.85	$ 592,176	$ 106,390	$ 203,644	$ 4,000	$ 60,757	$ 60,757	$ 430,165
2033	158	139	$ 3.85	$ 3.85	$ 534,497	$ 89,349	$ 190,713	$ -	$ 54,839	$ 54,839	$ 378,294
2034	143	125	$ 3.85	$ 3.85	$ 480,663	$ 102,705	$ 178,602	$ 100,000	$ 49,316	$ 49,316	$ 255,449
2035	129	113	$ 3.85	$ 3.85	$ 434,519	$ 87,628	$ 167,261	$ 40,000	$ 44,582	$ 44,582	$ 270,304
2036	117	101	$ 3.85	$ 3.85	$ 388,375	$ 74,076	$ 156,640	$ 4,000	$ 39,847	$ 39,847	$ 261,964
2037	104	91	$ 3.85	$ 3.85	$ 349,922	$ 91,084	$ 146,693	$ 104,000	$ 35,902	$ 35,902	$ 154,411
2038	94	82	$ 3.85	$ 3.85	$ 315,315	$ 79,889	$ 137,378	$ 24,000	$ 32,351	$ 32,351	$ 201,474
2039	85	74	$ 3.85	$ 3.85	$ 284,552	$ 69,035	$ 128,655	$ -	$ 29,195	$ 29,195	$ 195,738
2040	77	66	$ 3.85	$ 3.85	$ 253,790	$ 59,876	$ 120,485	$ -	$ 26,039	$ 26,039	$ 167,142
2041	70	60	$ 3.85	$ 3.85	$ 230,718	$ 50,909	$ 112,834	$ 80,000	$ 23,672	$ 23,672	$ 65,121
2042	64	54	$ 3.85	$ 3.85	$ 207,646	$ 43,617	$ 105,670	$ 4,000	$ 21,305	$ 21,305	$ 120,289
2043	58	48	$ 3.85	$ 3.85	$ 184,574	$ 37,129	$ 98,959	$ 24,000	$ 18,937	$ 19,332	$ 79,412
2044	52	44	$ 3.85	$ 3.85	$ 169,193	$ 30,916	$ 92,676	$ -	$ 17,359	$ 17,359	$ 90,074
2045	47	39	$ 3.85	$ 3.85	$ 149,967	$ 23,926	$ 86,791	$ -	$ 15,387	$ 15,387	$ 71,716
2046	37	35	$ 3.85	$ 3.85	$ 134,586	$ 2,279	$ 81,279	$ 132,000	$ 13,808	$ 13,808	$ (90,224)
2047		32	$ 3.85	$ 3.85	$ 123,050	$ -	$ 76,118		$ 12,625	$ 12,625	$ 34,306
2048		29	$ 3.85	$ 3.85	$ 111,514	$ -	$ 71,285		$ 11,441	$ 11,441	$ 28,788
2049		26	$ 3.85	$ 3.85	$ 99,978	$ -	$ 66,758		$ 10,258	$ 10,258	$ 22,962
2050		23	$ 3.85	$ 3.85	$ 88,442	$ -	$ 62,519		$ 9,074	$ 9,074	$ 16,849
2051		21	$ 3.85	$ 3.85	$ 80,751	$ -	$ 58,549		$ 8,285	$ 8,285	$ 13,917
2052		19	$ 3.85	$ 3.85	$ 73,061	$ -	$ 54,831		$ 7,496	$ 7,496	$ 10,734
2053		17	$ 3.85	$ 3.85	$ 65,370	$ -	$ 51,349		$ 6,707	$ 6,707	$ 7,314
2054		15	$ 3.85	$ 3.85	$ 57,680	$ -	$ 48,089		$ 5,918	$ 5,918	$ 3,673
2055		14	$ 3.85	$ 3.85	$ 53,834	$ -	$ 45,035		$ 5,523	$ 5,523	$ 3,276
2056		12	$ 3.85	$ 3.85	$ 46,144	$ -	$ 42,175		$ 4,734	$ 4,734	$ (766)
2057		11	$ 3.85	$ 3.85	$ 42,298	$ -	$ 39,497		$ 4,340	$ 4,340	$ (1,539)
2058		10	$ 3.85	$ 3.85	$ 38,453	$ -	$ 36,989		$ 3,945	$ 3,945	$ (2,481)
	13,766.7	13,337.0			$ 38,336,107	$ 9,840,947	$ 11,059,342	$ 1,424,000	$ 3,933,285	$ 3,933,679	$ 31,760,034

NorthWestern Energy
Preliminary natural gas acquisition analysis
Confidential and for management discussion only
November 11, 2013

NGIII (Excludes Havre Pipeline Compamy and RB ROFR Wells)

Scenario:	Total PDP	
Bid (exclusive of $6.2M of HPC and $1.8M RB ROFR)	$62,571	*Input*
Total rate base estimate	$62,571	

Authorized ROE (Per 4/2013 Stip)	9.80%
Cost of Debt	4.00%
Equity % of Cap Structure	47.67%
Weighted Average Cost of Capital (WACC)	6.76%



Purchase of Reserves	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2043
Average Rate Base ($000's)	59,953	54,981	50,498	46,430	42,713	39,299	36,150	33,233	30,524	28,007	25,664	23,482	21,445	1,445
Production (Bcf)	5.47	4.88	4.41	4.01	3.68	3.38	3.12	2.89	2.68	2.49	2.31	2.15	2.00	0.41
Estimated Revenue Requirement ($000's)	$18,950	$17,765	$16,685	$15,704	$14,837	$14,029	$13,273	$12,576	$11,916	$11,283	$10,678	$10,115	$9,598	$2,884
Resulting Forward Prices ($/DKT)	$3.46	$3.64	$3.78	$3.91	$4.04	$4.15	$4.25	$4.35	$4.44	$4.54	$4.62	$4.71	$4.80	$7.02
31 Year NPV of revenue requirement ($000's)	**$149,464**													
20 Yr Levelized Price	**$4.10**	**$12,956**	**3,162**											
30 Yr Levelized Price	**$4.17**	**$11,732**	**2,815**											

Procure at Forward Curve														
AECO - 5 Strip @ 3/6/13	$ 3.19	$ 3.56	$ 3.77	$ 3.90	$ 4.14	$ 4.28	$ 4.36	$ 4.45	$ 4.54	$ 4.64	$ 4.73	$ 4.82	$ 4.92	$ 7.04
Revenue Requirement ($000's)	$ 17,433	$ 17,370	$ 16,602	$ 15,655	$ 15,211	$ 14,468	$ 13,629	$ 12,877	$ 12,180	$ 11,529	$ 10,920	$ 10,363	$ 9,843	$ 2,894
31 Year NPV of revenue requirement ($000's)	**$151,103**	*Or*	*1.10%*	*greater than purchase option*										
20 Yr Levelized Price	**$4.12**	**$13,018**	**3,162**											
30 Yr Levelized Price	**$4.21**	**$11,861**	**2,815**											

Proved Producing -1

	Well Count	Mdkt/yr	$/dkt AECO-5	Gas Revenues $	HPC & BP Pipeline Revenue Credit	Op. Expense + Property Taxes	Gathering & Transmission	Abandonment Costs	Salvage Value	Production Taxes	Net Revenues
	Adj. for ROFR		03/06/13					$10,000	60%	6.00%	
2013	780	5,472	$ 3.19	$ 17,432,848	$ 328,254	$ 2,886,627	$ 4,201,378		$ -	$ 1,045,971	$ 9,627,127
2014	774	4,879	$ 3.56	$ 17,370,333	$ 321,457	$ 2,864,422	$ 4,066,494	$ 60,000	$ 36,000	$ 1,042,220	$ 9,694,654
2015	769	4,409	$ 3.77	$ 16,602,426	$ 314,652	$ 2,845,918	$ 3,932,200	$ 50,000	$ 30,000	$ 996,146	$ 9,122,815
2016	761	4,014	$ 3.90	$ 15,655,150	$ 307,870	$ 2,816,312	$ 3,791,637	$ 80,000	$ 48,000	$ 939,309	$ 8,383,762
2017	754	3,676	$ 4.14	$ 15,210,526	$ 301,073	$ 2,790,406	$ 3,658,979	$ 70,000	$ 42,000	$ 912,632	$ 8,121,583
2018	745	3,382	$ 4.28	$ 14,468,180	$ 294,289	$ 2,757,099	$ 3,527,499	$ 90,000	$ 54,000	$ 868,091	$ 7,573,781
2019	736	3,122	$ 4.36	$ 13,629,032	$ 287,500	$ 2,723,791	$ 3,402,665	$ 90,000	$ 54,000	$ 817,742	$ 6,936,333
2020	726	2,892	$ 4.45	$ 12,877,273	$ 280,713	$ 2,686,783	$ 3,282,144	$ 100,000	$ 60,000	$ 772,636	$ 6,376,422
2021	713	2,681	$ 4.54	$ 12,179,612	$ 273,945	$ 2,638,673	$ 3,159,611	$ 130,000	$ 78,000	$ 730,777	$ 5,872,496
2022	698	2,487	$ 4.64	$ 11,528,554	$ 267,184	$ 2,583,161	$ 3,037,525	$ 150,000	$ 90,000	$ 691,713	$ 5,423,340
2023	681	2,309	$ 4.73	$ 10,919,993	$ 260,431	$ 2,520,247	$ 2,916,318	$ 170,000	$ 102,000	$ 655,200	$ 5,020,659
2024	669	2,148	$ 4.82	$ 10,363,398	$ 253,625	$ 2,475,838	$ 2,810,750	$ 120,000	$ 72,000	$ 621,804	$ 4,660,632
2025	653	2,000	$ 4.92	$ 9,842,611	$ 246,848	$ 2,416,625	$ 2,702,399	$ 160,000	$ 96,000	$ 590,557	$ 4,315,879
2026	636	1,863	$ 5.02	$ 9,355,260	$ 240,067	$ 2,353,711	$ 2,596,958	$ 170,000	$ 102,000	$ 561,316	$ 4,015,343
2027	619	1,737	$ 5.12	$ 8,898,194	$ 233,277	$ 2,290,797	$ 2,495,969	$ 170,000	$ 102,000	$ 533,892	$ 3,742,812
2028	594	1,667	$ 5.23	$ 8,712,119	$ 226,545	$ 2,197,605	$ 2,422,673	$ 251,816	$ 151,089	$ 522,727	$ 3,694,931
2029	570	1,545	$ 5.33	$ 8,237,541	$ 219,781	$ 2,110,103	$ 2,309,756	$ 236,441	$ 141,865	$ 494,252	$ 3,448,634
2030	547	1,432	$ 5.44	$ 7,790,902	$ 212,996	$ 2,026,005	$ 2,202,773	$ 227,244	$ 136,346	$ 467,454	$ 3,216,769
2031	527	1,328	$ 5.55	$ 7,368,863	$ 206,183	$ 1,948,878	$ 2,102,607	$ 208,404	$ 125,042	$ 442,132	$ 2,998,068
2032	507	1,231	$ 5.66	$ 6,968,314	$ 199,353	$ 1,874,896	$ 2,007,109	$ 199,908	$ 119,945	$ 418,099	$ 2,787,599
2033	488	1,142	$ 5.77	$ 6,593,344	$ 192,497	$ 1,807,637	$ 1,918,479	$ 181,743	$ 109,046	$ 395,601	$ 2,591,427
2034	471	1,059	$ 5.89	$ 6,237,136	$ 185,628	$ 1,743,282	$ 1,833,864	$ 173,895	$ 104,337	$ 374,228	$ 2,401,832
2035	452	981	$ 6.01	$ 5,895,682	$ 178,762	$ 1,674,316	$ 1,749,810	$ 186,352	$ 111,811	$ 353,741	$ 2,222,036
2036	435	909	$ 6.13	$ 5,572,831	$ 171,884	$ 1,608,034	$ 1,669,729	$ 179,103	$ 107,462	$ 334,370	$ 2,060,941
2037	417	843	$ 6.25	$ 5,267,572	$ 164,996	$ 1,544,330	$ 1,593,405	$ 172,136	$ 103,282	$ 316,054	$ 1,909,925
2038	401	781	$ 6.38	$ 4,978,947	$ 158,106	$ 1,483,104	$ 1,520,636	$ 165,440	$ 99,264	$ 298,737	$ 1,768,401
2039	385	724	$ 6.50	$ 4,706,052	$ 151,222	$ 1,424,259	$ 1,451,235	$ 159,004	$ 95,403	$ 282,363	$ 1,635,815
2040	370	671	$ 6.63	$ 4,448,030	$ 144,363	$ 1,367,704	$ 1,385,034	$ 152,819	$ 91,691	$ 266,882	$ 1,511,646
2041	355	621	$ 6.77	$ 4,204,074	$ 137,571	$ 1,313,348	$ 1,321,896	$ 146,874	$ 88,125	$ 252,244	$ 1,395,406
2042	341	578	$ 6.90	$ 3,985,674	$ 130,977	$ 1,261,107	$ 1,264,108	$ 141,161	$ 84,697	$ 239,140	$ 1,295,832
2043	327	411	$ 7.04	$ 2,893,726	$ 125,253	$ 1,210,899	$ 1,034,148	$ 135,670	$ 81,402	$ 173,624	$ 546,041
2044				$ -	$ -		$ -				$ -
2045				$ -	$ -		$ -				$ -
2046				$ -	$ -		$ -				$ -
2047				$ -	$ -		$ -				$ -
2048				$ -	$ -		$ -				$ -
2049				$ -	$ -		$ -				$ -
2050				$ -	$ -		$ -				$ -
2051				$ -	$ -		$ -				$ -
2052				$ -	$ -		$ -				$ -
2053				$ -	$ -		$ -				$ -
2054				$ -	$ -		$ -				$ -
2055				$ -	$ -		$ -				$ -
2056				$ -	$ -		$ -				$ -
2057				$ -	$ -		$ -				$ -
2058				$ -	$ -		$ -				$ -
2059				$ -	$ -		$ -				$ -
		62,995.0		$ 290,194,195	$ 7,017,302	$ 66,245,917	$ 77,369,786	$ 4,528,011	$ 2,716,807	$ 17,411,652	$ 134,372,938

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF PATRICK E. CALLAHAN

ON BEHALF OF NORTHWESTERN ENERGY

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1 **Exhibits**

2	Natural Gas Transmission System Map	Exhibit__(PEC-1)
3	Oil & Gas Asset Clearinghouse Sales Offering	Exhibit__(PEC-2)
4	NFR Confidentiality Agreement	Exhibit__(PEC-3)
5	Clearinghouse Executive Summary	Exhibit__(PEC-4)
6	Stephan Smith NFR Summary	Exhibit__(PEC-5)
7	February 10, 2012 model	Exhibit__(PEC-6)
8	February 14, 2012 model	Exhibit__(PEC-7)
9	February 22, 2012 model	Exhibit__(PEC-8)
10	NFR Letter of Intent	Exhibit__(PEC-9)
11	NFR Asset Sales Agreement	Exhibit__(PEC-10)*
12	NFR Membership Interest PSA	Exhibit__(PEC-11)*
13	Devon Confidentiality Agreement	Exhibit__(PEC-12)
14	Devon Ownership Information	Exhibit__(PEC-13)
15	Stephan Smith Devon Summary	Exhibit__(PEC-14)
16	Devon Purchase and Sales Agreement	Exhibit__(PEC-15)*
17	Hohn Black Hills E&P Reserve Summary	Exhibit__(PEC-16)
18	Black Hills E&P Model	Exhibit__(PEC-17)
19	Valuation of Black Hills E&P Pipeline Interest	Exhibit__(PEC-18)
20	Black Hills E&P Asset Sales Agreement	Exhibit__(PEC-19)*
21	Black Hills E&P Membership Sales Agreement	Exhibit__(PEC-20)*
22	Calculated Royalty and Working Interest Purchases	Exhibit__(PEC-21)
23	$50 Minimum Justification	Exhibit__(PEC-22)
24	Minimum Royalty Purchases	Exhibit__(PEC-23)
25	Stephan Smith Summary for NFR Oil Assets Sale	Exhibit__(PEC-24)
26	Oil Sales Package	Exhibit__(PEC-25)
27	Behm Purchase and Sales Agreement	Exhibit__(PEC-26)*

* Exhibits on attached CD.

1 **Witness Information**

2 **Q. What is your name and business address?**

3 **A.** My name is Patrick E. Callahan and my business address is 11 East

4 Park Street, Butte, Montana 59701.

5

6 **Q. Please set forth your educational background and business**

7 **experience.**

8 **A.** I have Bachelor of Science and Master of Science degrees in

9 Petroleum Engineering from Montana Tech. I have been employed by

10 the Gas Department at The Montana Power Company and

11 NorthWestern Energy ("NorthWestern") for 42 years in various

12 technical and supervisory positions with responsibility in the areas of

13 natural gas production and storage. For the last seven years I have

14 been Director of Gas Growth and Storage.

15

16 In my positions, I have always been responsible for studying and

17 analyzing oil, gas, and gas storage reservoirs and looking for

18 opportunities to improve NorthWestern's storage operations through

19 drilling, completions, production equipment, or a different contractual

20 approach. I also work to protect NorthWestern's storage reservoirs,

21 and track and confirm storage inventory. I am responsible for the

22 maintenance of wells for both safety and reliability. I focus on

1 acquiring natural gas reserves to aid in meeting NorthWestern's core
2 customers' natural gas supply needs.
3
4 **Q. Have you testified before the Montana Public Service**
5 **Commission ("Commission") in the past?**
6 **A.** Yes, I have testified in several proceedings, including the Battle Creek
7 Natural Gas Properties ("Battle Creek") case filed in March of 2012
8 with the Commission under Docket No. D2012.3.25.
9
10 **Purpose of Testimony**
11 **Q. Please describe the purpose of your testimony.**
12 **A.** My testimony addresses the following NorthWestern purchases of the
13 various working interests of natural gas reserves and associated
14 gathering systems:
15 1. Purchase of the Bear Paw Assets ("Bear Paw (NFR)") from
16 NFR Energy LLC ("NFR") in 2012;
17 2. Purchase of 75% membership in the Lodge Creek Gathering
18 System LLC from NFR;
19 3. Purchase of 75% membership interest in Willow Creek
20 Gathering System LLC from NFR;
21 4. Purchase of the Bear Paw South Assets ("South Bear Paw
22 (Devon)") from Devon Energy Production Company L.P.
23 ("Devon") in 2013;

5. Purchase of Black Hills Exploration and Production Inc.'s ("Black Hills E&P") natural gas reserves and membership interests in Willow Creek and Lodge Creek Pipelines in 2015;
6. Purchase of various royalty and working interests in natural gas reserves; and
7. The sale of oil assets included in the purchase of Bear Paw to Behm Energy in 2013.

Purchase of the Natural Gas Assets

Q. What was your role in the acquisition of Bear Paw (NFR) and Bear Paw South (Devon)?

A. I performed an engineering review of the reservoir and operations data supplied by The Oil & Gas Asset Clearinghouse ("The Clearinghouse") for reasonableness in the Bear Paw (NFR) acquisition and a similar review of the data supplied by Devon in the South Bear Paw (Devon) Acquisition. I supplied information to Stephan R. Smith, a Registered Professional Petroleum Engineer, who performed independent acquisition and reserve evaluations for NorthWestern on both Bear Paw (NFR) and South Bear Paw (Devon) (see the Prefiled Direct Testimony of Stephan R. Smith ("S. Smith Direct Testimony")). I also coordinated data access to ensure the information was available to various groups within NorthWestern that worked on the acquisition including finance, legal, regulatory,

1 operations, energy supply, and executive management. I presented
2 the information and analysis regarding the opportunity to purchase
3 Bear Paw (NFR) and South Bear Paw (Devon) to management for
4 their review.
5
6 **Q. Why did NorthWestern acquire the Bear Paw (NFR) and South**
7 **Bear Paw (Devon) assets?**
8 **A.** NorthWestern determined that the Bear Paw (NFR) and South Bear
9 Paw (Devon) properties represented an attractive opportunity for the
10 following reasons:
11 • Natural gas commodity prices had declined over the last several
12 years and, therefore, the price of natural gas assets had also
13 declined;
14 • NorthWestern had determined that ownership of a portion of the
15 natural gas supply needed to serve core customers would over
16 time provide a reliable natural gas supply and reduce exposure
17 to market price volatility, which mitigates customer rate changes;
18 • The Bear Paw (NFR) and South Bear Paw (Devon) assets
19 were located in mature natural gas fields with well-defined
20 production histories;
21 • The produced gas could be delivered into NorthWestern's
22 natural gas transmission system;

- The rate at which the gas was produced could be controlled by NorthWestern and increased through additional investment such as drilling;
- The majority of the asset values were in natural gas;
- The majority of the natural gas reserves were in the Proved Developed Producing category; and
- The fields were located in an area where NorthWestern has operating experience.

Proved Developed Producing ("PDP") reserves are natural gas or oil reserves that the existing wells are expected to produce with the current operations. On a risk basis, there is a 90% probability that the actual production will equal or exceed the PDP reserve estimate. There is a small risk that the estimated PDP reserve volume will not be realized, but an equal possibility that more gas or oil will be produced.

Some of the Bear Paw (NFR) and South Bear Paw (Devon) wells have been producing since the 1970s, while others have been producing for five to ten years. South Bear Paw (Devon) and Bear Paw (NFR) deliver natural gas to the Havre Pipeline both north and south of Havre, Montana. Exhibit__(PEC-1) is a natural gas transmission system map. The Havre Pipeline is at the northeast

corner of NorthWestern's system or in the center of the upper portion of the map. The Havre Pipeline interconnects with NorthWestern's natural gas transmission system at Blaine County #3, east of Big Sandy, Montana and at Blaine County #1, east of Havre. The Bear Paw (NFR) assets are in Signal Butte and St. Joes Road Field. The South Bear Paw (Devon) assets are in the six fields to the south of Havre.

NorthWestern assigned value to only the PDP gas and oil reserves and the interests in Havre Pipeline Company ("HPC") and the four associated gas gathering systems for evaluating the purchased assets.

Several NorthWestern employees, including the three employees who joined NorthWestern with the Battle Creek purchase in 2010, have experience with low-pressure producing natural gas reserves along the Montana Highline.

For all of the above reasons, NorthWestern recognized that Bear Paw (NFR) and South Bear Paw (Devon) would be good acquisitions for the benefit of its core customers.

1 **Q. Please comment on the size of the Bear Paw (NFR) and South**
2 **Bear Paw (Devon) purchases.**
3 **A.** NorthWestern purchased a net interest in Bear Paw (NFR) of 13.4
4 billion cubic feet ("Bcf") of natural gas reserves and initial net
5 production of 1.6 Bcf per year. There are also an estimated 136,500
6 barrels of PDP oil reserves with an initial net production rate of about
7 30 barrels per day. NorthWestern's total net interest in South Bear
8 Paw (Devon) represents 63.0 Bcf of natural gas reserves and initial
9 production of 5.5 Bcf per year.
10
11 NorthWestern hired nine former NFR employees and 29 former Devon
12 employees. NorthWestern integrated the field operation and
13 accounting processes into its existing operations. Bear Paw (NFR)
14 supplied about 5.0% and South Bear Paw (Devon) an additional
15 21.0% of NorthWestern's annual 20 million dekatherm ("Dkt") core
16 market for natural gas in 2015.
17
18 **Q. Did NorthWestern inform the Commission staff and the Montana**
19 **Consumer Counsel ("MCC") of NorthWestern's participation in**
20 **the Bear Paw (NFR) and South Bear (Devon) purchases?**
21 **A.** Yes. NorthWestern personnel informed both the Commission staff
22 and the MCC that NorthWestern was considering potential purchases
23 of gas reserves and gathering systems. Because NorthWestern was

bound by the confidentiality agreements, the information provided was generic in nature. In June 2013, in Docket No. D2013.6.51, NorthWestern requested the Commission waive provisions of Order No. 6505e and permit NorthWestern to own and operate HPC as a subsidiary.

Bear Paw (NFR) Assets

Q. Discuss the process that NorthWestern went through in purchasing Bear Paw (NFR).

A. In June of 2011, NorthWestern contacted NFR at its Houston office. NFR explained that it was interested in selling the NFR Montana properties and it was in the process of selecting a firm to act as a broker to sell the Montana properties along with other Rocky Mountain producing properties in separate packages. NFR told NorthWestern that the package should be available by September 2011. NFR chose The Clearinghouse to act as a broker to market the producing properties. The non-Montana properties were sold in the fall of 2011 and the Bear Paw (NFR) assets were offered for sale in early January 2012.

Q. How did NorthWestern become involved in the sales process?

A. The Clearinghouse announced the sale on January 4, 2012 and required a confidentiality agreement to be signed by all bidders to gain

1 access to a virtual data room containing information relevant to the
2 sale properties. The data room opened on January 6, 2012 with
3 offers initially due to The Clearinghouse on February 2; this due date
4 was later moved to February 13. The effective date of the sale was
5 set as January 1, 2012. Exhibit__(PEC-2) includes the sales offering
6 from The Clearinghouse. After legal review, NorthWestern signed the
7 confidentiality agreement with NFR on January 6, 2012, which is
8 attached as Exhibit__(PEC-3).
9
10 **Q. What was NFR actually offering in the Bear Paw (NFR) sale?**
11 **A.** NFR was selling its varying working interests in about 610 natural gas
12 wells, one water injection well and nine oil wells.[1] It was also selling
13 its 75% interest in two pipeline systems, which include approximately
14 400 miles of gathering lines and meter houses, 18 compressor sites,
15 and a dehydration system. The Willow Creek Gathering System
16 collects the natural gas both at the wellhead and gas delivered by the
17 Lodge Creek Gathering System, then compresses, dehydrates, and
18 delivers the natural gas to HPC's natural gas transmission system
19 north of Chinook, Montana. The Lodge Creek Gathering System
20 gathers gas to be delivered into Havre Pipeline southeast of Big
21 Sandy and gas to be delivered to Willow Creek north of Havre. The

[1] The working interest in a well is the owned share of the production before reductions for royalties. The working interest also represents the share of expenses due.

610 natural gas wells had an estimated net PDP natural gas reserve of 13.767 Bcf. The nine oil wells had an estimated net PDP oil reserve of 139,000 barrels. The volumes noted here are from The Clearinghouse summary. Redrock Drilling Company ("Redrock") was included in the sale package, but NorthWestern had no interest in the drilling company and did not bid on Redrock.

Q. How did NorthWestern use the reserve information?

A. NorthWestern reviewed the information supplied by The Clearinghouse and determined that the PDP reserve estimate was reasonable. NorthWestern decided to analyze the data in preparation for a possible bid on the Bear Paw (NFR) assets. The executive summary and asset review provided by The Clearinghouse is included as Exhibit__(PEC-4). The summary showed a net PDP reserve estimate of 13.767 Bcf of natural gas and 139,000 barrels of oil in the net PDP reserve category.

Q. How did NorthWestern use the well ownership information?

A. NorthWestern supplied the well ownership information along with operating and production tax expense information to Stephan R. Smith, a registered professional engineer who has experience in evaluating oil and natural gas reserves. Mr. S. Smith prepared an independent evaluation of the net PDP oil and gas reserves. Mr. S.

1 Smith used an AECO-based price forecast supplied by NorthWestern
2 and estimated PDP net gas reserves of 13.4 Bcf. The price forecast
3 supplied to Mr. S. Smith had an effective date of January 9, 2012. Mr.
4 S. Smith estimated PDP net oil reserves of 136,519 barrels using the
5 oil price forecast in The Clearinghouse evaluation (see S. Smith Direct
6 Testimony). These volumes are 2-3% smaller than The
7 Clearinghouse estimates. The Smith evaluation used a different price
8 forecast and Mr. Smith uses different software. The summary page
9 from Mr. S. Smith's evaluation is included as Exhibit__(PEC-5) (also
10 see S. Smith Direct Testimony and exhibits). Mr. S. Smith was also
11 asked to evaluate the natural gas reserves using a NYMEX-based
12 price forecast used by The Clearinghouse. Smith's analysis found
13 13.75 Bcf compared to The Clearinghouse value of 13.767 Bcf – only
14 a 0.15% difference between the two estimates.
15
16 **Q. Did purchasing the Willow Creek and Lodge Creek Pipelines**
17 **provide any benefits to NorthWestern's customers?**
18 **A.** Yes. It provided NorthWestern control of the gas flow in the pipelines,
19 along with the ability to optimize the compression for the benefit of
20 NorthWestern's production and not have NorthWestern subject to third
21 party gathering costs.
22
23 **Q. What was the next step in the process?**

1 **A.** NorthWestern prepared a current natural gas price forecast
2 specifically tied to gas production in the Bear Paw (NFR) area. The
3 price forecast was an AECO minus $0.05 ("AECO-5") forecast, based
4 on a price strip dated February 10, 2012. NorthWestern utilized the
5 information in hand to calculate an estimated purchase price and a
6 revenue requirement for the Bear Paw (NFR) assets. The resulting
7 estimated revenue requirement was then compared to the estimated
8 cost of buying the same amount of natural gas at the February 10th
9 AECO-5 natural gas price forecast. This comparison showed that
10 NorthWestern's natural gas customers were neutral at a purchase
11 price close to $19.0 million. The evaluation is included as
12 Exhibit__(PEC-6).
13
14 The 10% discounted net present value ("NPV") cost to NorthWestern's
15 customers would be the same whether NorthWestern purchased the
16 Bear Paw (NFR) interest at $19.0 million or bought natural gas at a
17 price of AECO-5. Included in the sale was an estimated $800,000
18 worth of pipe inventory. Based on the calculated neutral cost point for
19 its customers, plus 50% of the inventory value, which totaled $19.4
20 million, NorthWestern determined that at a purchase price of $19.1
21 million, utility customers would benefit compared to the option of
22 purchasing natural gas supply priced at AECO-5.
23

1 A bid of $19.1 million was submitted to The Clearinghouse on
2 February 13, 2012. The bid breakdown was $13.58 million for the gas
3 producing assets, $2.7 million for the oil producing assets, $2.42
4 million for the membership interests in the gas gathering LLCs, and
5 $400,000 for the pipe inventory.
6
7 **Q. Is the AECO-5 gas price forecast correct for this analysis?**
8 **A.** Yes, the AECO-5 gas price made sense for several reasons. First,
9 gas being purchased by NorthWestern in this area was priced at
10 AECO-5. The volume of gas available to NorthWestern is declining.
11 This decline can be replaced with gas delivered at the Carway import
12 point from Alberta, but the price to acquire additional volumes at
13 Carway can be greater than AECO-5 and in time will require additional
14 capital investment on the gas transmission system.
15
16 **Q. What was NFR's response to NorthWestern's $19.1 million bid?**
17 **A.** On February 14, 2012, NorthWestern was notified by The
18 Clearinghouse that NFR had received three or four bids for the Bear
19 Paw (NFR) assets that were too close for NFR to make a final choice.
20 The Clearinghouse requested a new bid to be submitted by 5 p.m. on
21 February 16.
22
23 **Q. What was NorthWestern's response to the request?**

1 **A.** NorthWestern regrouped and confirmed that Bear Paw (NFR) was an
2 asset beneficial to the utility and its customers and recalculated the
3 revenue requirement with an updated natural gas price forecast dated
4 February 14, 2012. The updated analysis showed that the neutral
5 point for customers had moved to $19.35 million due to an increase in
6 natural gas prices (+$250,000). This updated analysis is included as
7 Exhibit__(PEC-7). A timely bid of $19.3 million was submitted on
8 February 16.
9
10 **Q. What was the outcome of the $19.3 million bid?**
11 **A.** The outcome was similar to the first bid. On February 22, 2012, NFR
12 notified NorthWestern that its Board had reviewed the $19.3 million
13 bid. NFR then asked NorthWestern to submit another bid before
14 5 p.m. on February 24. NFR indicated it would accept a bid closer to
15 $25 million.
16
17 **Q. What was NorthWestern's response to the $25 million bid**
18 **request?**
19 **A.** NorthWestern again ran the model with an updated natural gas price
20 forecast dated February 22, 2012, and the model showed a new
21 customer breakeven point of $19.515 (+$165,000) million. This model
22 is included as Exhibit__(PEC-8). NorthWestern determined that it
23 would not make a $25 million bid. Taking into account the low gas

1 prices in February 2012, the decision was made to make a final offer
2 of $19.5 million. The bid breakdown was $14.38 million for the gas
3 producing assets, $2.7 million for the oil producing assets, and $2.42
4 million for the gas gathering LLCs. On February 24, the final offer was
5 submitted to NFR. NFR presented the bid to its Board.
6
7 NFR verbally accepted the $19.5 million offer. A "letter of intent"
8 between NorthWestern and NFR was agreed to and signed on April 9,
9 2012. It is provided as Exhibit__(PEC-9).
10
11 **Q. Describe the development of the sales agreements.**
12 **A.** NorthWestern hired the Crowley Fleck law firm and Stinson Morrison
13 Hecker LLP to help develop the sales agreements with NFR. Two
14 agreements were required, one for purchase of the reserves, leases,
15 and wells, and one for purchase of the membership interests in the
16 pipeline LLCs. A draft Asset Sales Agreement ("ASA") and a draft
17 Membership Interest Purchase and Sales Agreement ("MIPSA") were
18 provided by NFR and, following negotiation, the documents were
19 signed on August 8, 2012. Prior to the closing, NorthWestern
20 performed a "due diligence" review of the Bear Paw (NFR) assets.
21 The final title conveyance documents were signed and payment made
22 on August 31, 2012. NorthWestern assumed operations on
23 September 3, 2012. The ASA and MIPSA between NFR and

1 NorthWestern are Exhibit__(PEC-10) and Exhibit__(PEC-11),
2 respectively. These voluminous exhibits have been provided on CD.
3
4 **Q. Which areas of Bear Paw (NFR) did NorthWestern review during**
5 **the due diligence process?**
6 **A.** NorthWestern enlisted two contractors to perform due diligence: KC
7 Harvey for the on-site environmental compliance inspection and Pacer
8 Energy, LLC to ensure correct land and lease ownership.
9 NorthWestern's accounting and financial staff communicated with
10 NFR staff to review accounting, invoicing, and payment processes.
11
12 **Q. Did the due diligence process uncover any significant problems?**
13 **A.** The environmental inspection under the MIPSA found concerns at ten
14 of the compressor sites caused by hydrocarbon-stained soil. The
15 estimated cost of proper clean-up and disposal was $208,000. NFR
16 at its option chose to clean the sites at its own expense. An amount
17 proportionate to NFR's 75% interest in the pipeline LLCs of $156,000
18 was withheld from the August 31 payment at closing. Prior to the final
19 settlement, NFR remediated eight of the ten sites noted in due
20 diligence. The $156,000 withheld at closing was reduced to $90,000
21 to cover the two remaining sites in the final settlement. Clean-up was
22 verified by NorthWestern. In 2015, one of the remaining sites was

1 remediated by NorthWestern at a cost of less than $10,000. The
2 remaining site will be addressed in the near term.
3
4 There were also title defects found in the due diligence process; the
5 majority were minor with the exception of two wells. The Shrauger 29-
6 3-36-16 well had a defect amount of $130,806. NFR claimed an
7 87.5% revenue interest in the well, and initial documents provided
8 showed a 62.625% revenue interest. Further review indicated that a
9 25% working interest partner chose not to participate in the well and,
10 therefore, under the joint operating agreement, NFR received the
11 partner's revenue interest. This information eliminated the defect and
12 confirmed NFR's 87.5% revenue interest.
13
14 Second, the Paulsen Dir 31-1 well had a $72,458 defect. NFR
15 claimed a 26.06% revenue interest in this well, which is part of the
16 Tiger Ridge Unit. It was determined that NFR was paid based on
17 0.093765% of the total unit production rather than on the individual
18 well production. Per the terms of the ASA which set a hurdle level of
19 $150,000 before an adjustment to the purchase price would be made
20 for title defects, no adjustment was made to the purchase price for the
21 Paulsen Dir 31-1.
22

1 Revenues received by NFR matched its revenue interests claimed in
2 the sales document on all wells except for the Paulsen Dir 31-1well
3 described above.
4
5 **Q. Were there any changes in the deal prior to closing?**
6 **A.** Yes. Two items impacted the original deal. First, a lawsuit against a
7 previous owner of the Bear Paw Asset and NFR was settled and the
8 settlement resulted in a small change in NFR's ownership interest in
9 200 wells. Within the terms of the ASA, NorthWestern was
10 indemnified from any negative results from the lawsuit. The
11 settlement reduced the purchase price by $104,315.
12
13 Second, NFR determined that the Starcher 30-32-19B well could not
14 be included due to the fact that the title was still held by the previous
15 owner of the Bear Paw Asset. Removal of the Starcher well reduced
16 the purchase price an additional $226,720.
17
18 In summary, the initial purchase price, subject to adjustment, was
19 reduced from $19.5 million to $19.2 million and the estimated total
20 PDP net natural gas reserves were reduced from 13.4 Bcf to 13.2 Bcf.
21
22 **Q. Was the interest in the Starcher well ultimately added to the**
23 **sale?**

1 **A.** Yes. The Starcher well was added to the sale effective September 1,
2 2012 at a price of $215,303 after NFR secured ownership. The price
3 was reduced by the $11,417 of revenues that NFR received for
4 production after January 1, 2012. This increased the estimated net
5 PDP for Bear Paw (NFR) to 13.4 Bcf.
6
7 **Q. Please compare the cost of the Battle Creek purchase to the Bear**
8 **Paw (NFR) purchase.**
9 **A.** The Battle Creek purchase equated to $1.47 per thousand standard
10 cubic feet ("mcf") in the ground and $8,702 per thousand cubic feet
11 per day ("mcf/d"); the Bear Paw (NFR) purchase (using the $14.38
12 million bid price for the gas assets and excluding the gathering
13 systems and oil wells) was $1.07/mcf in the ground and $3,245 per
14 mcf/d. The difference in the metrics is due mainly to the use of the
15 lower then-current 2012 natural gas market price forecast versus the
16 2010 forecast utilized in the Battle Creek transaction.
17
18 **Q. How does the quantity of natural gas in the Bear Paw (NFR) asset**
19 **fit into NorthWestern's natural gas portfolio?**
20 **A.** The estimated 2012 volume from the Bear Paw (NFR) asset of 1.6 Bcf
21 is 8.0% of the 20 Bcf/year portfolio. The 2012 owned gas volume
22 including Battle Creek production has a volume of 2.08 Bcf or 10.4%
23 of the portfolio.

Q. What is the present status of the Bear Paw (NFR) reserve purchases?

A. About 2.2 million cubic feet per day of Bear Paw (NFR) gas is delivered into NorthWestern's transmission system through Havre Pipeline to serve NorthWestern's core customers. As of July 1, 2016, the Bear Paw (NFR) wells have produced 5.6 Bcf of the estimated 13.4 Bcf purchased, or 41.5%.

South Bear Paw (Devon) Assets

Q. Describe the South Bear Paw (Devon) reserve purchase.

A. NorthWestern contacted Devon's Oklahoma City office in July 2012 regarding a possible sale of Devon's Montana gas producing assets. Devon agreed to discuss the possibility of a sale, and a confidentiality agreement (attached as Exhibit__(PEC-12)) was signed August 16, 2012. Devon then transmitted ownership information (attached as Exhibit__(PEC-13)) on Devon's 914 Montana wells to NorthWestern. Similar to the process utilized for the Bear Paw (NFR) purchase, this data was shared with Mr. S. Smith with a request for an economic and reserve evaluation. The evaluation resulted in an estimated 64.58 Bcf of PDP natural gas reserves owned by Devon. Please see Mr. S. Smith's summary page attached as Exhibit__(PEC-14) as well as the S. Smith Direct Testimony.

1 **Q. How did NorthWestern use the reserve evaluation prepared by**
2 **Mr. S. Smith?**
3 **A.** The estimated PDP volume was used in general discussions with
4 Devon. The value was comparable to the reserve value that Devon
5 carried and the sale process proceeded.
6
7 **Q. What was the next step in the process?**
8 **A.** Detailed historical financial information was provided by Devon
9 regarding operating expenses for the producing assets. This
10 operating expense information along with the predicted yearly net gas
11 production volumes were used as inputs by Mr. Travis Meyer in a
12 model to estimate a purchase price that would benefit NorthWestern's
13 utility natural gas customers over time. Details of this model are
14 contained in the Prefiled Direct Testimony of Travis E. Meyer ("Meyer
15 Direct Testimony").
16
17 **Q. Did Devon wish to sell any other assets?**
18 **A.** Yes, Devon wished to sell its 82.22% membership interest in HPC and
19 100% interest in Bear Paw Gathering. Devon owned 100% of Bear
20 Paw Gathering with 158 miles of gathering lines in Hill, Chouteau, and
21 Blaine Counties. Bear Paw Gathering uses over 4,000 horsepower of
22 compression.
23

1 **Q. Are HPC assets a part of this docket?**

2 **A.** No. HPC has separate rate making proceedings governed by the

3 Commission and is not part of this docket.

4

5 **Q. Did NorthWestern decide to purchase the South Bear Paw**

6 **(Devon) assets described above?**

7 **A.** Yes. Based on its analyses of these assets, including a comparison

8 to natural gas market purchases, NorthWestern decided to pursue a

9 purchase from Devon.

10

11 **Q. Describe the development of the South Bear Paw (Devon) sales**

12 **agreements.**

13 **A.** NorthWestern hired Stinson Morrison Hecker LLP to help develop the

14 sales agreements with Devon. Two agreements were required, one

15 for purchase of the reserves, leases, and wells and one for purchase

16 of the membership interests in the HPC. After discussion and

17 negotiation, final documents were signed on November 20, 2013.

18 Prior to the closing, NorthWestern performed a "due diligence" review

19 of the South Bear Paw (Devon) assets. Payment was made to Devon

20 on December 10, 2013. NorthWestern took over operations of South

21 Bear Paw (Devon) on December 1, 2013. The effective date of the

22 sale was January 1, 2013, which matches Mr. S. Smith's evaluation.

1 The ASA between Devon and NorthWestern is attached as
2 Exhibit__(PEC-15) (provided on CD).
3
4 **Q. Were there any changes in the deal before closing?**
5 **A.** Yes. The Chippewa Cree Tribe exercised its right of first refusal and
6 purchased Devon's interest in 15 wells in December 2013. This
7 resulted in a reduction in the purchase price of $1,446,957 and a
8 reduction in the estimated reserves purchase by 1.57 Bcf.
9
10 The base purchase price, subject to adjustment, was reduced from
11 $64.0 million to $62.6 million, and the estimated total PDP net natural
12 gas reserves were reduced from 64.58 Bcf to 63.0 Bcf.
13
14 **Q. Please explain the due diligence process.**
15 **A.** NorthWestern again enlisted two contractors to perform due diligence:
16 KC Harvey for the on-site environmental compliance inspection and
17 Pacer Energy, LLC to ensure correct land and lease ownership.
18 NorthWestern accounting and financial staff communicated with
19 Devon staff to review accounting, invoicing, and payment processes.
20
21 **Q. Did the due diligence process uncover problems?**
22 No. Neither the environmental nor the title due diligence processes
23 uncovered any significant problems.

1 Revenues received by Devon matched its revenue interests claimed
2 in the sales document on all wells.
3
4 **Q. Please compare the cost of the Battle Creek purchase to the**
5 **South Bear Paw (Devon) purchase.**
6 **A.** The Battle Creek purchase equated to $1.47 per mcf in the ground
7 and $8,702 per mcf/d; the South Bear Paw (Devon) purchase was
8 $0.99/mcf in the ground and $4,651 per mcf/d. The difference in the
9 metrics is due to the lower then-current 2013 natural gas market price
10 forecast versus the 2010 forecast utilized in the Battle Creek
11 transaction.
12
13 **Q. How does the quantity of natural gas in the South Bear Paw**
14 **(Devon) asset fit into the natural gas portfolio?**
15 **A.** The estimated 2013 volume from the South Bear Paw (Devon) asset
16 of 5.47 Bcf is 27.35% of the 20 Bcf/year portfolio. The 2013 owned
17 gas volume was 7.2 Bcf or 36.0% of the portfolio.
18
19 **Q. What is the present status of South Bear Paw (Devon)?**
20 **A.** About 11.1 million cubic feet per day of South Bear Paw (Devon) gas
21 is delivered through Havre Pipeline into NorthWestern's transmission
22 system to serve the core market. The South Bear Paw (Devon) wells

have produced 16.6 Bcf of the estimated 63.0 Bcf purchased as of July 1, 2016 or 26.4%.

Black Hills Assets

Q. Describe the Black Hills reserve purchase.

A. Black Hills contacted NorthWestern in 2015 and indicated that Black Hills E&P wished to sell its oil and gas interests in Montana. Black Hills E&P owned a 25% membership interest in both the Lodge Creek and the Willow Creek Pipeline, along with interests in 263 gas wells and two oil wells. NorthWestern is the operator of the majority of these gas wells and pipelines. NorthWestern also owned the remaining 75% of the membership in the pipelines.

NorthWestern transmitted ownership information on the wells to Hohn Engineering and requested an economic and reserve evaluation. This evaluation is included and addressed in the Prefiled Direct Testimony of Thomas K. Hohn. The evaluation resulted in an estimated 1.22 Bcf of net PDP natural gas reserves owned by Black Hills E&P along with 4,357 barrels of net oil reserves. The summary sheet from Mr. Hohn's evaluation is included as Exhibit__(PEC-16).

Q. How was the information from the reserve evaluation used?

1 **A.** The Hohn information along with operating expense data was input in
2 the utility model, and a breakeven price for our customers of $505,000
3 was estimated. Exhibit__(PEC-17) shows this model run.
4
5 **Q. How was the value of the 25% membership interests determined?**
6 **A.** An estimated value for the pipeline was based on the book value of
7 the 75% membership interest in the Bear Paw (NFR) Assets.
8 Exhibit__(PEC-18) shows the calculation of the potential value for the
9 25% membership interests of $888,999.
10
11 **Q. What are the benefits of NorthWestern's purchase of Black Hills**
12 **E&P's interests?**
13 **A.** NorthWestern is the operator of the two pipelines and most of the
14 wells. The natural gas flows through the gathering pipelines to
15 NorthWestern's customers. The purchase consisted of buying a
16 larger piece of the pipelines and wells that NorthWestern currently
17 owned. If Black Hills E&P was willing to accept less than the
18 breakeven price shown in the model, purchasing this asset was the
19 right thing to do. Additional reasons for purchasing assets like Black
20 Hills are discussed previously in my testimony.
21
22 **Q. How did NorthWestern proceed?**

1 **A.** NorthWestern made a nonbinding offer to purchase the wells, leases,
2 and reserves for $500,000 and the two membership interests for
3 $875,000. Black Hills E&P accepted the offer. The Purchase and
4 Sales Agreement for reserves and Membership Agreement are
5 attached as Exhibit__(PEC-19) and Exhibit__(PEC-20), respectively
6 (both on CD). They were signed on December 18, 2015. The
7 effective date of the sale was July 1, 2015.
8
9 **Q. How does the quantity of natural gas in the Black Hills asset fit**
10 **into the natural gas portfolio?**
11 **A.** The estimated 2015 volume from the Black Hills asset of 0.09 Bcf is
12 0.45% of the 20 Bcf/year portfolio. The 2015 owned gas volume was
13 5.75 Bcf or 28.8% of the portfolio.
14
15 **Q. What is the present status of the Black Hills reserve purchase?**
16 **A.** About 0.4 million cubic feet per day of Black Hills gas is delivered
17 through Havre Pipeline into NorthWestern's transmission system to
18 serve the core market. The Black Hills E&P well interests have
19 produced 0.171 Bcf of the estimated 1.2 Bcf purchased as of July 1,
20 2016 or 14.5%.

1 **Smaller Working and Royalty Interest Purchases**

2 **Q. Please describe any other natural gas assets that have been**
3 **purchased.**

4 **A.** NorthWestern has been approached by both royalty and working
5 interest owners wishing to sell their interest. These sales fall into a
6 calculated value category and a minimum value category.
7 Exhibit__(PEC-21) shows several purchases where the value of the
8 royalty or working interest has been calculated using one of the
9 following methods: the same revenue requirement model used to
10 analyze the Bear Paw (NFR) and South Bear Paw (Devon)
11 purchases, an analysis based on the individual well value established
12 in the South Bear Paw (Devon) purchase, or by declining and
13 discounting the yearly royalty payments. The process of valuing the
14 smaller interests has evolved over the last several years, and
15 NorthWestern now consistently uses the revenue requirement model.
16
17 When it is obvious from the payment history that the value of the
18 interests is less than $50.00, a minimum offer of $50.00 will be made
19 for royalty interests being paid by NorthWestern. Exhibit__(PEC-22)
20 shows a 3-year payout assumption was used to establish the $50.00
21 minimum payment. NorthWestern will benefit by no longer issuing at
22 least one check per year and a 1099 tax statement. There are several
23 other reductions in NorthWestern's administration expenses regarding

1 royalties that are difficult to define in terms of dollars; these benefits
2 are also noted on Exhibit__(PEC-22). Exhibit__(PEC-23) shows the
3 royalty interests purchased by NorthWestern at the $50 minimum.
4 The total of the various small purchases is less than 1% of the natural
5 gas portfolio.
6
7 **2013 Sale of Bear Paw (NFR) Oil Assets**
8 **Q. Please discuss the 2013 sale of the Bear Paw (NFR) oil interests.**
9 **A.** The 2012 purchase of the Bear Paw (NFR) assets included interests
10 in nine oil wells valued by NorthWestern at $2.7 million. As a natural
11 gas utility, NorthWestern considered it prudent to determine whether
12 the nine oil wells could be sold. Mr. S. Smith was requested to
13 perform an economic and reservoir analysis of NorthWestern's
14 interests in the nine oil wells in October 2012. Mr. S. Smith's
15 summary is attached as Exhibit__(PEC-24) and shows a net PDP
16 reserve volume of 128,677 barrels of oil and an estimated value using
17 a 10% discount factor of $2.7 million.
18
19 **Q. How did NorthWestern proceed?**
20 **A.** The attached sales package included as Exhibit__(PEC-25) was
21 assembled and sent out to prospective buyers in January 2013.
22 These companies were chosen based on their knowledge of other oil
23 interests in Northern Montana. After word of the sale spread, a few

other companies asked to be included, and sales packages were also sent to them. Thirteen companies received the sales package. The due date for the bids was set for February 28, 2013.

Q. What bids did NorthWestern receive?

A. Eleven bids were received ranging from $750,000 to $3,232,000.

Q. Were the nine oil wells sold?

A. Yes. Behm Energy was the successful bidder. Exhibit__(PEC-26) (provided on CD) is the purchase and sale agreement that was signed on May 13, 2013. A $250,000 deposit was received from Behm on May 13, 2013. Following due diligence by Behm Energy, the closing payment was made on July 22, 2013 in the amount of $2,838,406.67 for a total payment of $3,088,406.67. The difference between the bid and payments is the result of the net revenues that NorthWestern received between January and May 2013 and other small adjustments. This oil sale, which benefits customers, was reflected as a reduction to rate base as explained in the Prefiled Direct Testimony of Crystal D. Lail.

Summary

Q. Would you summarize NorthWestern's recent gas production history?

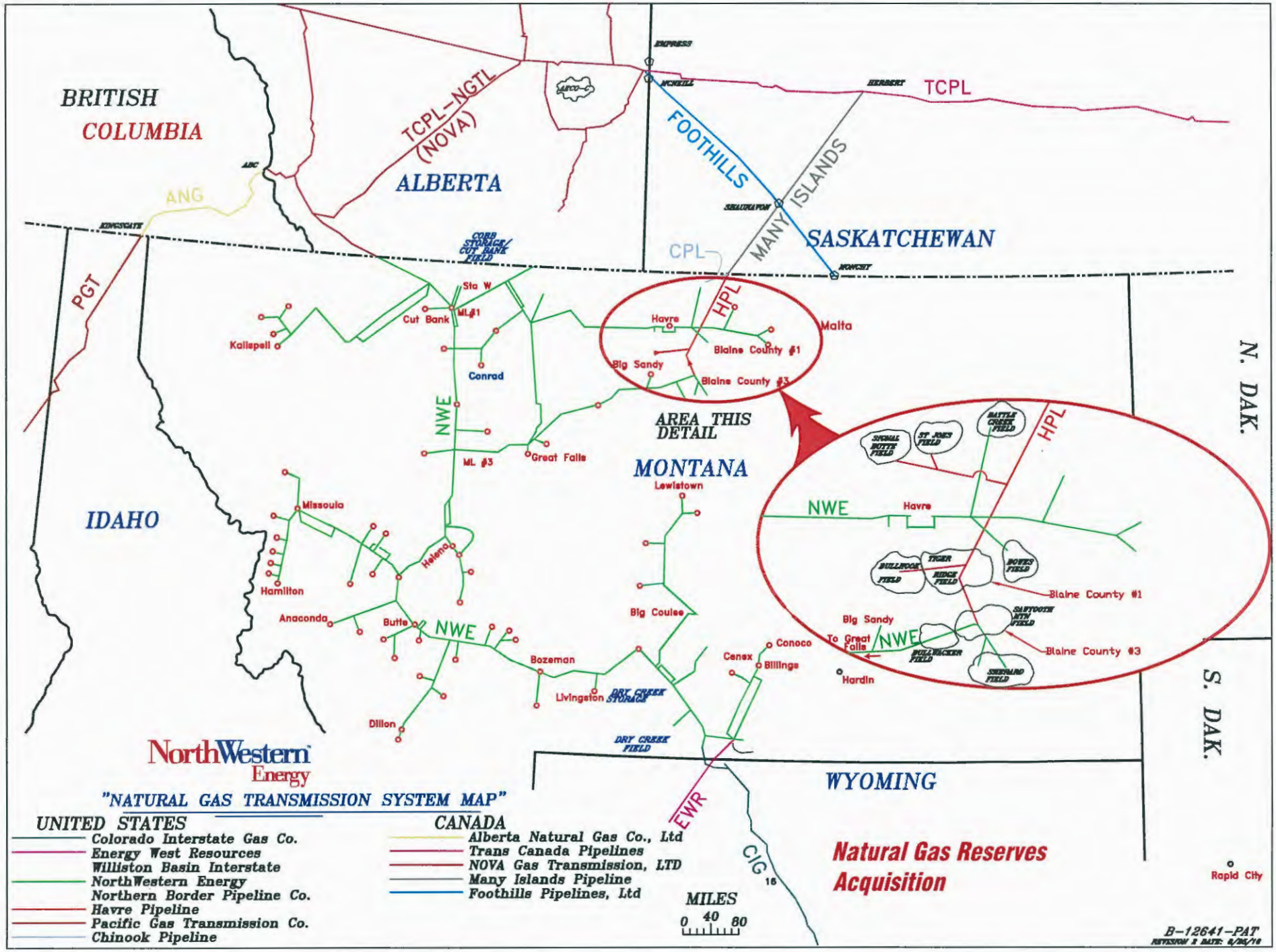
1 **A.** NorthWestern has had gas production assets since August of 2010.
2 In the last six years NorthWestern has purchased an estimated 86.1
3 Bcf of PDP natural gas reserves. The production from date of
4 purchase through the end of 2015 is 22.27 Bcf or 25.9% of the
5 estimated gas reserves. The production models used at the time of
6 asset purchase predicted 22.32 Bcf through the year 2015. The
7 actual production is only 0.25% lower than the models.
8
9 In 2013, after purchasing the South Bear Paw (Devon) assets,
10 NorthWestern's owned gas production supplied 36.1% of the core
11 customers' 20 million Dkt per year market. In 2017, NorthWestern's
12 owned gas production will supply an estimated 24.5% of the core
13 market. The NorthWestern-owned gas production will continue to
14 decline each year and therefore supply less of the core market.
15 Between 2014 and 2015, production of the owned natural gas assets
16 has declined 7% to 13% annually. As noted above, the total net
17 production at the end of 2015 was an excellent match to the original
18 forecasted production. Economics of the recent low natural gas prices
19 in 2016 have caused some reduction in production as partners have
20 requested that wells be shut-in until natural gas prices rebound. It is
21 also difficult to justify additional investments with no return for our
22 partners. With the exception of nine wells, the wells that were shut-in
23 were returned to production in September 2016 as natural gas prices

increased. The remaining nine wells will return to production as gas prices reach appropriate levels.

The production history based on NorthWestern's experience with its owned natural gas assets indicates that the estimated gas volumes will be produced.

Q. Does this conclude your testimony?

A. Yes, it does.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TCPL-NGTL (NOVA)
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KINGSGATE
ABC
CORB STORAGE/ CUT BANK FIELD
Sta W
Cut Bank
ML#1
Kalispell
Conrad
Havre
Malta
Blaine County #1
Big Sandy
Blaine County #3
Great Falls
ML #3
AREA THIS DETAIL
Lewistown
Missoula
Helena
Hamilton
Anaconda
Butte
Big Coulee
Bozeman
Livingston
DRY CREEK STORAGE
Dillon
Conoco
Cenex
Billings
Hardin
DRY CREEK FIELD
Rapid City
SIGNAL BUTTE FIELD
ST JOES FIELD
BATTLE CREEK FIELD
BULLFOOT FIELD
TIGER RIDGE FIELD
BOWES FIELD
SARTOOTH NTH FIELD
BULLWACKER FIELD
SHERBURN FIELD
To Great Falls
NorthWestern Energy
"NATURAL GAS TRANSMISSION SYSTEM MAP"
UNITED STATES
Colorado Interstate Gas Co.
Energy West Resources
Williston Basin Interstate
NorthWestern Energy
Northern Border Pipeline Co.
Havre Pipeline
Pacific Gas Transmission Co.
Chinook Pipeline
CANADA
Alberta Natural Gas Co., Ltd
Trans Canada Pipelines
NOVA Gas Transmission, LTD
Many Islands Pipeline
Foothills Pipelines, Ltd
MILES
0 40 80
Natural Gas Reserves Acquisition
B-12641-PAT

GRAND TOTAL
NFR BEAR PAW BASIN, LLC
MONTANA

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SETUP FILE : TOGAC

THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----
01-2012	367.0	2.308	393.789	1.055	151.940	76.859	2.136	81.057	324.498
12-2012	381.5	74.031	6809.925	30.342	2991.404	76.711	2.006	2327.592	6001.987
12-2013	442.7	136.336	11553.128	59.509	5791.498	72.909	2.242	4338.773	12986.550
12-2014	505.8	175.345	14373.716	81.571	7022.087	69.672	2.425	5683.200	17031.455
12-2015	545.6	177.875	13935.499	83.658	6712.929	68.334	2.554	5716.713	17143.057
12-2016	530.2	168.514	9451.798	79.251	4440.265	68.075	2.693	5395.047	11957.674
12-2017	512.3	159.696	7254.564	75.100	3354.727	68.357	2.835	5133.563	9511.042
12-2018	493.5	151.381	5831.550	71.186	2679.271	68.358	2.842	4866.083	7614.938
12-2019	479.8	142.667	4880.512	66.963	2223.042	68.358	2.851	4577.413	6336.961
12-2020	469.8	135.221	4184.057	63.454	1892.135	68.358	2.858	4337.604	5406.816
12-2021	459.8	128.261	3638.260	60.185	1638.997	68.359	2.862	4114.168	4691.569
12-2022	451.0	121.577	3207.784	57.046	1433.980	68.360	2.869	3899.656	4114.631
12-2023	437.9	114.910	2847.674	53.914	1266.916	68.363	2.874	3685.722	3640.732
12-2024	431.1	109.112	2561.284	51.192	1133.841	68.363	2.878	3499.639	3263.019
12-2025	417.4	103.085	2298.349	48.276	1014.160	68.365	2.881	3300.408	2922.169
S TOT	1.1	1900.317	93221.898	882.701	43747.211	69.057	2.582	60956.641	112947.086
AFTER	1.1	1299.803	17455.594	608.327	7409.303	68.368	2.924	41589.816	21667.738
TOTAL	1.1	3200.120	110677.484	1491.029	51156.516	68.776	2.631	102546.453	134614.828

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	405.554	37.965	0.000	74.626	74.626	-25.769	318.733	318.733	317.571
12-2012	8329.579	414.926	0.000	951.863	951.863	5438.411	1524.382	1843.114	1754.244
12-2013	17325.324	702.631	0.000	1367.929	1367.929	7697.209	7557.555	9400.669	8232.312
12-2014	22714.656	1137.040	0.000	1710.766	1710.766	4513.169	15353.662	24754.332	20237.332
12-2015	22859.768	1522.105	0.000	1935.851	1935.851	-5537.867	24939.684	49694.016	38104.160
12-2016	17352.723	1518.738	0.000	1951.502	1951.502	-1906.051	15688.530	65382.543	48294.383
12-2017	14644.605	1364.583	0.000	1938.601	1938.601	-1438.169	12779.591	78162.133	55840.461
12-2018	12481.022	1166.252	0.000	1887.598	1887.598	-1142.761	10569.932	88732.062	61513.887
12-2019	10914.374	1023.484	0.000	1819.095	1819.095	-944.186	9015.980	97748.047	65913.203
12-2020	9744.421	911.300	0.000	1791.400	1791.400	-800.866	7842.587	105590.633	69392.078
12-2021	8805.737	822.701	0.000	1766.885	1766.885	-691.918	6908.070	112498.703	72177.859
12-2022	8014.287	746.028	0.000	1731.533	1731.533	-603.830	6140.557	118639.266	74429.062
12-2023	7326.454	682.586	0.000	1679.896	1679.896	-533.083	5497.055	124136.320	76261.156
12-2024	6762.658	627.087	0.000	1662.307	1662.307	-476.156	4949.420	129085.742	77760.789
12-2025	6222.577	578.959	0.000	1602.015	1602.015	-425.904	4467.507	133553.250	78991.367
S TOT	173903.750	13356.384	0.000	23871.865	23871.865	3122.249	133553.250	133553.250	78991.367
AFTER	63257.562	5893.726	0.000	19488.018	19488.018	-3212.007	41087.824	174641.094	84889.023
TOTAL	237161.312	19250.109	0.000	43359.883	43359.883	-89.758	174641.078	174641.094	84889.023

	OIL	GAS
GROSS WELLS	33.0	676.0
GROSS ULT., MB & MMF	3910.181	292075.438
GROSS CUM., MB & MMF	710.061	181397.938
GROSS RES., MB & MMF	3200.120	110677.484
NET RES., MB & MMF	1491.029	51156.512
NET REVENUE, M$	102546.461	134614.766
INITIAL PRICS, $	60.741	1.925
INITIAL N.I., PCT.	45.722	37.834
FINAL N.I., PCT.	54.203	28.984

LIFE, YRS.	44.00
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	0.00
DISCOUNTED PAYOUT, YRS.	0.00
UNDISCOUNTED NET/INVEST.	*******
DISCOUNTED NET/INVEST.	13.56
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	60.876
FINAL W.I., PCT.	33.125

P.W. %	P.W., M$
5.00	115650.172
8.00	95203.398
10.00	84889.023
12.00	76413.000
15.00	66203.172
18.00	58156.281
20.00	53679.062
30.00	38020.574
50.00	22673.098
100.00	9996.607

TOTAL - EAGLE RESERVOIR
NER BEAR PAW BASIN, LLC
MONTANA

DATE : 12/27/2011
TIME : 10:22:09
DBS FILE : Clearing
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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$-----	NET GAS SALES -----M$-----
01-2012	247.0	0.000	299.567	0.000	96.299	0.000	2.269	0.000	218.513
12-2012	250.1	0.000	3833.792	0.000	1260.152	0.000	2.202	0.000	2774.458
12-2013	256.2	0.000	5085.021	0.000	1925.096	0.000	2.448	0.000	4712.636
12-2014	283.7	0.000	8418.124	0.000	3596.772	0.000	2.544	0.000	9150.623
12-2015	311.6	0.000	9914.245	0.000	4427.125	0.000	2.622	0.000	11608.640
12-2016	302.3	0.000	7004.496	0.000	3057.548	0.000	2.761	0.000	8443.110
12-2017	289.8	0.000	5400.544	0.000	2317.233	0.000	2.909	0.000	6740.507
12-2018	275.2	0.000	4355.827	0.000	1851.083	0.000	2.918	0.000	5400.544
12-2019	267.8	0.000	3655.769	0.000	1536.100	0.000	2.928	0.000	4497.709
12-2020	261.2	0.000	3138.076	0.000	1305.772	0.000	2.937	0.000	3835.041
12-2021	253.8	0.000	2730.370	0.000	1130.136	0.000	2.943	0.000	3326.137
12-2022	249.8	0.000	2421.122	0.000	993.878	0.000	2.951	0.000	2932.485
12-2023	242.1	0.000	2156.679	0.000	880.195	0.000	2.955	0.000	2601.145
12-2024	238.7	0.000	1946.942	0.000	789.845	0.000	2.959	0.000	2337.449
12-2025	230.1	0.000	1755.439	0.000	710.160	0.000	2.962	0.000	2103.251
S TOT	26.2	0.000	62116.016	0.000	25877.396	0.000	2.731	0.000	70682.242
AFTER	26.2	0.000	14688.674	0.000	5878.700	0.000	2.971	0.000	17464.967
TOTAL	26.2	0.000	76804.688	0.000	31756.096	0.000	2.776	0.000	88147.211

--END-- MO-YEAR	TOT NET REVENUE -----M$-----	NET PROD TAXES -----M$-----	NET ADVAL TAXES -----M$-----	OPERATING EXPENSE -----M$-----	TOTAL EXPENSE -----M$-----	CAPITAL INVESTMENT -----M$-----	FUTURE NET CASHFLOW -----M$-----	CUMUL NET CASHFLOW -----M$-----	10.0% CUM DISC CF -----M$-----
01-2012	218.513	20.639	0.000	37.607	37.607	4.017	156.251	156.251	155.615
12-2012	2774.458	211.632	0.000	427.533	427.533	842.125	1293.167	1449.418	1369.234
12-2013	4712.636	282.620	0.000	521.727	521.727	3199.219	709.070	2158.489	1992.029
12-2014	9150.623	400.644	0.000	654.433	654.433	4383.805	3711.742	5870.231	4944.911
12-2015	11608.640	659.566	0.000	778.764	778.764	0.000	10170.311	16040.542	12262.624
12-2016	8443.110	797.701	0.000	780.378	780.378	0.000	6865.029	22905.572	16747.037
12-2017	6740.507	639.385	0.000	768.487	768.487	0.000	5332.636	28238.207	19912.035
12-2018	5400.544	514.100	0.000	732.533	732.533	0.000	4153.911	32392.119	22152.578
12-2019	4497.709	429.546	0.000	718.780	718.780	0.000	3349.383	35741.504	23794.578
12-2020	3835.041	366.725	0.000	703.032	703.032	0.000	2765.283	38506.789	25026.799
12-2021	3326.137	318.110	0.000	685.676	685.676	0.000	2322.352	40829.141	25967.463
12-2022	2932.485	280.822	0.000	677.678	677.678	0.000	1973.984	42803.125	26694.273
12-2023	2601.145	249.216	0.000	658.212	658.212	0.000	1693.717	44496.840	27261.162
12-2024	2337.449	223.811	0.000	650.246	650.246	0.000	1463.392	45960.230	27706.416
12-2025	2103.251	201.637	0.000	631.328	631.328	0.000	1270.287	47230.520	28057.766
S TOT	70682.242	5596.155	0.000	9426.414	9426.414	8429.165	47230.520	47230.520	28057.766
AFTER	17464.967	1674.138	0.000	6428.657	6428.657	0.000	9362.174	56592.699	29500.820
TOTAL	88147.211	7270.293	0.000	15855.071	15855.071	8429.165	56592.695	56592.699	29500.820

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	0.0	417.0	LIFE, YRS.	38.00	5.00	39312.777
GROSS ULT., MB & MMF	0.000	233929.484	DISCOUNT %	10.00	8.00	32862.184
GROSS CUM., MB & MMF	0.000	157124.781	UNDISCOUNTED PAYOUT, YRS.	0.00	10.00	29500.824
GROSS RES., MB & MMF	0.000	76804.703	DISCOUNTED PAYOUT, YRS.	0.00	12.00	26682.781
NET RES., MB & MMF	0.000	31756.096	UNDISCOUNTED NET/INVEST.	7.71	15.00	23222.184
NET REVENUE, M$	0.000	88147.219	DISCOUNTED NET/INVEST.	5.25	18.00	20446.305
INITIAL PRICE, $	0.000	1.821	RATE-OF-RETURN, PCT.	100.00	20.00	18884.914
INITIAL N.I., PCT.	0.000	30.803	INITIAL W.I., PCT.	54.699	30.00	13348.902
FINAL N.I., PCT.	0.000	49.063	FINAL W.I., PCT.	55.840	50.00	7879.049
					100.00	3462.712

PDP - EAGLE RESERVOIR
NER BEAR PAW BASIN, LLC
MONTANA

DATE : 12/27/2011
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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----
01-2012	247.0	0.000	299.567	0.000	96.299	0.000	2.269	0.000	218.513
12-2012	243.5	0.000	2928.071	0.000	939.119	0.000	2.264	0.000	2126.218
12-2013	236.6	0.000	2667.845	0.000	850.535	0.000	2.608	0.000	2217.962
12-2014	229.2	0.000	2299.357	0.000	728.273	0.000	2.801	0.000	2040.173
12-2015	223.6	0.000	2024.496	0.000	638.834	0.000	2.942	0.000	1879.739
12-2016	214.3	0.000	1801.999	0.000	566.923	0.000	3.078	0.000	1745.222
12-2017	201.8	0.000	1610.704	0.000	506.627	0.000	3.228	0.000	1635.146
12-2018	187.2	0.000	1424.556	0.000	452.785	0.000	3.216	0.000	1455.950
12-2019	179.8	0.000	1295.134	0.000	411.327	0.000	3.218	0.000	1323.669
12-2020	173.2	0.000	1180.687	0.000	373.998	0.000	3.222	0.000	1204.966
12-2021	165.8	0.000	1071.015	0.000	340.832	0.000	3.221	0.000	1097.760
12-2022	161.8	0.000	989.741	0.000	313.441	0.000	3.226	0.000	1011.154
12-2023	154.1	0.000	904.495	0.000	285.257	0.000	3.229	0.000	921.014
12-2024	150.7	0.000	838.763	0.000	263.565	0.000	3.229	0.000	851.046
12-2025	142.1	0.000	765.127	0.000	240.040	0.000	3.230	0.000	775.337
S TOT	26.2	0.000	22101.555	0.000	7007.855	0.000	2.926	0.000	20503.869
AFTER	26.2	0.000	6349.953	0.000	2053.384	0.000	3.217	0.000	6606.000
TOTAL	26.2	0.000	28451.506	0.000	9061.239	0.000	2.992	0.000	27109.869

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	218.513	20.639	0.000	37.607	37.607	0.000	160.268	160.268	159.632
12-2012	2126.218	206.706	0.000	409.056	409.056	0.000	1510.457	1670.725	1597.371
12-2013	2217.962	226.747	0.000	440.609	440.609	0.000	1550.606	3221.331	2944.226
12-2014	2040.173	209.537	0.000	435.531	435.531	0.000	1395.105	4616.436	4045.539
12-2015	1879.739	191.509	0.000	432.454	432.454	0.000	1255.777	5872.213	4946.596
12-2016	1745.222	177.477	0.000	425.410	425.410	0.000	1142.334	7014.547	5691.676
12-2017	1635.146	166.629	0.000	409.488	409.488	0.000	1059.030	8073.577	6319.534
12-2018	1455.950	148.830	0.000	373.534	373.534	0.000	933.586	9007.163	6822.666
12-2019	1323.669	135.630	0.000	359.781	359.781	0.000	828.258	9835.421	7228.442
12-2020	1204.966	123.180	0.000	344.033	344.033	0.000	737.753	10573.174	7557.012
12-2021	1097.760	111.762	0.000	326.677	326.677	0.000	659.321	11232.495	7823.951
12-2022	1011.154	102.907	0.000	318.680	318.680	0.000	589.567	11822.062	8040.949
12-2023	921.014	93.636	0.000	299.213	299.213	0.000	528.165	12350.227	8217.669
12-2024	851.046	86.170	0.000	291.247	291.247	0.000	473.629	12823.856	8361.738
12-2025	775.337	78.672	0.000	272.329	272.329	0.000	424.336	13248.192	8479.078
S TOT	20503.869	2080.031	0.000	5175.648	5175.648	0.000	13248.192	13248.192	8479.078
AFTER	6606.000	668.598	0.000	2880.098	2880.098	0.000	3057.305	16305.498	8969.178
TOTAL	27109.869	2748.629	0.000	8055.746	8055.746	0.000	16305.498	16305.498	8969.178

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	0.0	329.0	LIFE, YRS.	34.67	5.00	11559.285
GROSS ULT., MB & MMF	0.000	185576.281	DISCOUNT %	10.00	8.00	9845.450
GROSS CUM., MB & MMF	0.000	157124.781	UNDISCOUNTED PAYOUT, YRS.	0.00	10.00	8969.177
GROSS RES., MB & MMF	0.000	28451.508	DISCOUNTED PAYOUT, YRS.	0.00	12.00	8244.120
NET RES., MB & MMF	0.000	9061.239	UNDISCOUNTED NET/INVEST.	0.00	15.00	7365.757
NET REVENUE, M$	0.000	27109.871	DISCOUNTED NET/INVEST.	0.00	18.00	6670.131
INITIAL PRICE, $	0.000	0.000	RATE-OF-RETURN, PCT.	100.00	20.00	6281.838
INITIAL N.I., PCT.	0.000	30.803	INITIAL W.I., PCT.	0.000	30.00	4913.717
FINAL N.I., PCT.	0.000	34.660	FINAL W.I., PCT.	38.912	50.00	3531.794
					100.00	2255.461

PDNP - EAGLE RESERVOIR
NFR BEAR PAW BASIN, LLC
MONTANA

DATE : 12/27/2011
TIME : 10:21:59
DBS FILE : Clearing
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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----
01-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	1.0	0.000	122.621	0.000	25.603	0.000	2.319	0.000	59.383
12-2013	1.0	0.000	81.818	0.000	17.084	0.000	2.676	0.000	45.711
12-2014	1.0	0.000	55.985	0.000	11.690	0.000	2.875	0.000	33.608
12-2015	1.0	0.000	41.525	0.000	8.670	0.000	3.020	0.000	26.185
12-2016	1.0	0.000	32.448	0.000	6.775	0.000	3.159	0.000	21.402
12-2017	1.0	0.000	26.299	0.000	5.491	0.000	3.310	0.000	18.175
12-2018	1.0	0.000	21.900	0.000	4.573	0.000	3.310	0.000	15.135
12-2019	1.0	0.000	18.621	0.000	3.888	0.000	3.310	0.000	12.869
12-2020	1.0	0.000	16.098	0.000	3.361	0.000	3.310	0.000	11.126
12-2021	1.0	0.000	14.106	0.000	2.945	0.000	3.310	0.000	9.749
12-2022	1.0	0.000	12.500	0.000	2.610	0.000	3.310	0.000	8.639
12-2023	1.0	0.000	11.182	0.000	2.335	0.000	3.310	0.000	7.728
12-2024	1.0	0.000	10.083	0.000	2.105	0.000	3.310	0.000	6.969
12-2025	1.0	0.000	9.157	0.000	1.912	0.000	3.310	0.000	6.328
S TOT	1.0	0.000	474.341	0.000	99.042	0.000	2.857	0.000	283.006
AFTER	1.0	0.000	93.949	0.000	19.617	0.000	3.310	0.000	64.929
TOTAL	1.0	0.000	568.290	0.000	118.659	0.000	2.932	0.000	347.935

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	0.000	0.000	0.000	0.000	0.000	4.017	-4.017	-4.017	-4.017
12-2012	59.383	0.451	0.000	1.185	1.185	0.000	57.747	53.730	51.066
12-2013	45.711	3.838	0.000	1.310	1.310	0.000	40.562	94.292	86.376
12-2014	33.608	3.112	0.000	1.343	1.343	0.000	29.153	123.445	109.419
12-2015	26.185	2.425	0.000	1.377	1.377	0.000	22.383	145.829	125.496
12-2016	21.402	1.982	0.000	1.411	1.411	0.000	18.009	163.838	137.251
12-2017	18.175	1.683	0.000	1.427	1.427	0.000	15.065	178.903	146.188
12-2018	15.135	1.402	0.000	1.427	1.427	0.000	12.307	191.210	152.824
12-2019	12.869	1.192	0.000	1.427	1.427	0.000	10.251	201.460	157.849
12-2020	11.126	1.030	0.000	1.427	1.427	0.000	8.668	210.129	161.711
12-2021	9.749	0.903	0.000	1.427	1.427	0.000	7.419	217.548	164.715
12-2022	8.639	0.800	0.000	1.427	1.427	0.000	6.412	223.959	167.076
12-2023	7.728	0.716	0.000	1.427	1.427	0.000	5.585	229.545	168.945
12-2024	6.969	0.645	0.000	1.427	1.427	0.000	4.896	234.441	170.434
12-2025	6.328	0.586	0.000	1.427	1.427	0.000	4.315	238.757	171.628
S TOT	283.006	20.764	0.000	19.468	19.468	4.017	238.757	238.757	171.628
AFTER	64.929	6.012	0.000	29.015	29.015	0.000	29.902	268.658	176.519
TOTAL	347.935	26.777	0.000	48.484	48.484	4.017	268.658	268.658	176.519

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	0.0	1.0	LIFE, YRS.	34.33	5.00	210.891
GROSS ULT., MB & MMF	0.000	568.290	DISCOUNT %	10.00	8.00	188.460
GROSS CUM., MB & MMF	0.000	0.000	UNDISCOUNTED PAYOUT, YRS.	0.15	10.00	176.519
GROSS RES., MB & MMF	0.000	568.290	DISCOUNTED PAYOUT, YRS.	0.15	12.00	166.342
NET RES., MB & MMF	0.000	118.659	UNDISCOUNTED NET/INVEST.	67.88	15.00	153.583
NET REVENUE, M$	0.000	347.935	DISCOUNTED NET/INVEST.	44.94	18.00	143.082
INITIAL PRICE, $	0.000	2.319	RATE-OF-RETURN, PCT.	100.00	20.00	137.041
INITIAL N.I., PCT.	0.000	20.880	INITIAL W.I., PCT.	26.780	30.00	114.488
FINAL N.I., PCT.	0.000	20.880	FINAL W.I., PCT.	26.780	50.00	88.944
					100.00	61.389

PUD - EAGLE RESERVOIR
NFR BEAR PAW BASIN, LLC
MONTANA

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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----
01-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	5.6	0.000	783.099	0.000	295.430	0.000	1.993	0.000	588.856
12-2013	11.0	0.000	1110.245	0.000	415.261	0.000	2.296	0.000	953.560
12-2014	11.0	0.000	720.741	0.000	269.711	0.000	2.468	0.000	665.526
12-2015	11.0	0.000	518.083	0.000	193.930	0.000	2.592	0.000	502.682
12-2016	11.0	0.000	396.471	0.000	148.436	0.000	2.711	0.000	402.468
12-2017	11.0	0.000	316.580	0.000	118.541	0.000	2.841	0.000	336.782
12-2018	11.0	0.000	260.691	0.000	97.623	0.000	2.841	0.000	277.358
12-2019	11.0	0.000	219.739	0.000	82.294	0.000	2.841	0.000	233.809
12-2020	11.0	0.000	188.645	0.000	70.653	0.000	2.841	0.000	200.738
12-2021	11.0	0.000	164.359	0.000	61.560	0.000	2.841	0.000	174.905
12-2022	11.0	0.000	144.951	0.000	54.293	0.000	2.841	0.000	154.259
12-2023	11.0	0.000	129.142	0.000	48.374	0.000	2.841	0.000	137.440
12-2024	11.0	0.000	116.057	0.000	43.474	0.000	2.841	0.000	123.519
12-2025	11.0	0.000	105.077	0.000	39.362	0.000	2.841	0.000	111.836
S TOT	7.1	0.000	5173.879	0.000	1938.940	0.000	2.508	0.000	4863.736
AFTER	7.1	0.000	798.397	0.000	270.508	0.000	2.951	0.000	798.392
TOTAL	7.1	0.000	5972.276	0.000	2209.448	0.000	2.563	0.000	5662.129

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	588.856	4.475	0.000	17.292	17.292	842.125	-275.037	-275.037	-279.203
12-2013	953.560	40.670	0.000	37.938	37.938	0.000	874.952	599.915	483.402
12-2014	665.526	61.628	0.000	38.887	38.887	0.000	565.011	1164.926	930.179
12-2015	502.682	46.548	0.000	39.859	39.859	0.000	416.275	1581.201	1229.250
12-2016	402.468	37.269	0.000	40.855	40.855	0.000	324.344	1905.545	1441.012
12-2017	336.782	31.186	0.000	41.319	41.319	0.000	264.277	2169.822	1597.825
12-2018	277.358	25.683	0.000	41.319	41.319	0.000	210.355	2380.177	1711.276
12-2019	233.809	21.651	0.000	41.319	41.319	0.000	170.839	2551.016	1795.026
12-2020	200.738	18.588	0.000	41.319	41.319	0.000	140.830	2691.846	1857.783
12-2021	174.905	16.196	0.000	41.319	41.319	0.000	117.390	2809.236	1905.335
12-2022	154.259	14.284	0.000	41.319	41.319	0.000	98.655	2907.891	1941.663
12-2023	137.440	12.727	0.000	41.319	41.319	0.000	83.394	2991.285	1969.579
12-2024	123.519	11.438	0.000	41.319	41.319	0.000	70.762	3062.047	1991.112
12-2025	111.836	10.356	0.000	41.319	41.319	0.000	60.161	3122.208	2007.755
S TOT	4863.736	352.699	0.000	546.704	546.704	842.125	3122.208	3122.208	2007.755
AFTER	798.392	73.931	0.000	232.383	232.383	0.000	492.078	3614.286	2081.510
TOTAL	5662.129	426.631	0.000	779.087	779.087	842.125	3614.286	3614.286	2081.510

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	0.0	11.0	LIFE, YRS.	35.58	5.00	2650.036
GROSS ULT., MB & MMF	0.000	5972.276	DISCOUNT %	10.00	8.00	2279.024
GROSS CUM., MB & MMF	0.000	0.000	UNDISCOUNTED PAYOUT, YRS.	1.31	10.00	2081.510
GROSS RES., MB & MMF	0.000	5972.276	DISCOUNTED PAYOUT, YRS.	1.37	12.00	1912.954
NET RES., MB & MMF	0.000	2209.448	UNDISCOUNTED NET/INVEST.	5.29	15.00	1701.249
NET REVENUE, M$	0.000	5662.129	DISCOUNTED NET/INVEST.	3.58	18.00	1526.654
INITIAL PRICE, $	0.000	2.023	RATE-OF-RETURN, PCT.	100.00	20.00	1426.123
INITIAL N.I., PCT.	0.000	37.726	INITIAL W.I., PCT.	43.142	30.00	1051.130
FINAL N.I., PCT.	0.000	33.645	FINAL W.I., PCT.	39.322	50.00	633.295
					100.00	214.273

PRB - EAGLE RESERVOIR
NFR BEAR PAW BASIN, LLC
MONTANA

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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$-----	NET GAS SALES -----M$-----
01-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2013	7.6	0.000	1225.113	0.000	642.216	0.000	2.329	0.000	1495.403
12-2014	32.0	0.000	3659.649	0.000	1748.430	0.000	2.499	0.000	4369.270
12-2015	32.0	0.000	2294.811	0.000	1100.088	0.000	2.625	0.000	2887.657
12-2016	32.0	0.000	1617.751	0.000	776.973	0.000	2.746	0.000	2133.336
12-2017	32.0	0.000	1222.608	0.000	587.895	0.000	2.877	0.000	1691.362
12-2018	32.0	0.000	967.750	0.000	465.732	0.000	2.877	0.000	1339.913
12-2019	32.0	0.000	791.778	0.000	381.277	0.000	2.877	0.000	1096.945
12-2020	32.0	0.000	664.095	0.000	319.941	0.000	2.877	0.000	920.486
12-2021	32.0	0.000	567.883	0.000	273.690	0.000	2.877	0.000	787.425
12-2022	32.0	0.000	493.196	0.000	237.766	0.000	2.877	0.000	684.072
12-2023	32.0	0.000	433.805	0.000	209.186	0.000	2.877	0.000	601.848
12-2024	32.0	0.000	385.632	0.000	185.995	0.000	2.877	0.000	535.127
12-2025	32.0	0.000	345.899	0.000	166.861	0.000	2.877	0.000	480.078
S TOT	21.7	0.000	14669.970	0.000	7096.048	0.000	2.681	0.000	19022.922
AFTER	21.7	0.000	2954.604	0.000	1327.079	0.000	2.847	0.000	3778.407
TOTAL	21.7	0.000	17624.574	0.000	8423.128	0.000	2.707	0.000	22801.328

--END-- MO-YEAR	TOT NET REVENUE -----M$-----	NET PROD TAXES -----M$-----	NET ADVAL TAXES -----M$-----	OPERATING EXPENSE -----M$-----	TOTAL EXPENSE -----M$-----	CAPITAL INVESTMENT -----M$-----	FUTURE NET CASHFLOW -----M$-----	CUMUL NET CASHFLOW -----M$-----	10.0% CUM DISC CF -----M$-----
01-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2013	1495.403	11.365	0.000	41.870	41.870	3199.219	-1757.050	-1757.050	-1521.975
12-2014	4369.270	110.848	0.000	137.248	137.248	0.000	4121.175	2364.125	1743.270
12-2015	2887.657	267.397	0.000	140.679	140.679	0.000	2479.581	4843.706	3525.992
12-2016	2133.336	197.547	0.000	144.196	144.196	0.000	1791.592	6635.298	4696.231
12-2017	1691.362	156.620	0.000	145.834	145.834	0.000	1388.908	8024.207	5520.617
12-2018	1339.913	124.076	0.000	145.834	145.834	0.000	1070.003	9094.209	6097.820
12-2019	1096.945	101.577	0.000	145.834	145.834	0.000	849.534	9943.743	6514.350
12-2020	920.486	85.237	0.000	145.834	145.834	0.000	689.415	10633.158	6821.598
12-2021	787.425	72.916	0.000	145.834	145.834	0.000	568.675	11201.833	7051.972
12-2022	684.072	63.345	0.000	145.834	145.834	0.000	474.893	11676.726	7226.849
12-2023	601.848	55.731	0.000	145.834	145.834	0.000	400.283	12077.009	7360.843
12-2024	535.127	49.553	0.000	145.834	145.834	0.000	339.740	12416.749	7464.227
12-2025	480.078	44.455	0.000	145.834	145.834	0.000	289.789	12706.538	7544.392
S TOT	19022.922	1340.666	0.000	1776.499	1776.499	3199.219	12706.538	12706.538	7544.392
AFTER	3778.407	349.880	0.000	1331.398	1331.398	0.000	2097.129	14803.667	7864.553
TOTAL	22801.328	1690.547	0.000	3107.896	3107.896	3199.219	14803.667	14803.667	7864.553

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	0.0	32.0	LIFE, YRS.	36.92	5.00	10433.985
GROSS ULT., MB & MMF	0.000	17624.572	DISCOUNT %	10.00	8.00	8754.155
GROSS CUM., MB & MMF	0.000	0.000	UNDISCOUNTED PAYOUT, YRS.	2.43	10.00	7864.553
GROSS RES., MB & MMF	0.000	17624.572	DISCOUNTED PAYOUT, YRS.	2.47	12.00	7110.059
NET RES., MB & MMF	0.000	8423.129	UNDISCOUNTED NET/INVEST.	5.63	15.00	6171.485
NET REVENUE, M$	0.000	22801.330	DISCOUNTED NET/INVEST.	3.88	18.00	5408.060
INITIAL PRICE, $	0.000	2.376	RATE-OF-RETURN, PCT.	100.00	20.00	4974.185
INITIAL N.I., PCT.	0.000	52.507	INITIAL W.I., PCT.	56.068	30.00	3407.616
FINAL N.I., PCT.	0.000	42.993	FINAL W.I., PCT.	49.586	50.00	1814.718
					100.00	520.781

POS - EAGLE RESERVOIR
NFR BEAR PAW BASIN, LLC
MONTANA

DATE : 12/27/2011
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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----
01-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2013	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2014	10.5	0.000	1682.393	0.000	838.669	0.000	2.435	0.000	2042.046
12-2015	44.0	0.000	5035.331	0.000	2485.503	0.000	2.540	0.000	6312.378
12-2016	44.0	0.000	3155.827	0.000	1558.441	0.000	2.657	0.000	4140.682
12-2017	44.0	0.000	2224.354	0.000	1098.680	0.000	2.784	0.000	3059.042
12-2018	44.0	0.000	1680.931	0.000	830.372	0.000	2.785	0.000	2312.188
12-2019	44.0	0.000	1330.496	0.000	657.315	0.000	2.785	0.000	1830.418
12-2020	44.0	0.000	1088.552	0.000	537.818	0.000	2.785	0.000	1497.725
12-2021	44.0	0.000	913.007	0.000	451.109	0.000	2.785	0.000	1256.299
12-2022	44.0	0.000	780.735	0.000	385.768	0.000	2.785	0.000	1074.362
12-2023	44.0	0.000	678.055	0.000	335.043	0.000	2.785	0.000	933.115
12-2024	44.0	0.000	596.407	0.000	294.706	0.000	2.785	0.000	820.789
12-2025	44.0	0.000	530.179	0.000	261.985	0.000	2.785	0.000	729.671
S TOT	26.2	0.000	19696.264	0.000	9735.508	0.000	2.672	0.000	26008.715
AFTER	26.2	0.000	4491.771	0.000	2208.113	0.000	2.816	0.000	6217.242
TOTAL	26.2	0.000	24188.035	0.000	11943.621	0.000	2.698	0.000	32225.955

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2013	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2014	2042.046	15.520	0.000	41.425	41.425	4383.805	-2398.702	-2398.702	-1883.497
12-2015	6312.378	151.687	0.000	164.395	164.395	0.000	5996.295	3597.594	2435.291
12-2016	4140.682	383.427	0.000	168.505	168.505	0.000	3588.749	7186.342	4780.868
12-2017	3059.042	283.267	0.000	170.419	170.419	0.000	2605.356	9791.698	6327.874
12-2018	2312.188	214.109	0.000	170.419	170.419	0.000	1927.660	11719.358	7367.994
12-2019	1830.418	169.497	0.000	170.419	170.419	0.000	1490.502	13209.860	8098.914
12-2020	1497.725	138.689	0.000	170.419	170.419	0.000	1188.617	14398.477	8628.697
12-2021	1256.299	116.333	0.000	170.419	170.419	0.000	969.547	15368.024	9021.492
12-2022	1074.362	99.486	0.000	170.419	170.419	0.000	804.457	16172.481	9317.741
12-2023	933.115	86.406	0.000	170.419	170.419	0.000	676.289	16848.770	9544.130
12-2024	820.789	76.005	0.000	170.419	170.419	0.000	574.365	17423.135	9718.908
12-2025	729.671	67.568	0.000	170.419	170.419	0.000	491.684	17914.818	9854.917
S TOT	26008.715	1801.994	0.000	1908.094	1908.094	4383.805	17914.818	17914.818	9854.917
AFTER	6217.242	575.716	0.000	1955.762	1955.762	0.000	3685.761	21600.580	10409.064
TOTAL	32225.955	2377.710	0.000	3863.856	3863.856	4383.805	21600.580	21600.580	10409.064

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	0.0	44.0	LIFE, YRS.	38.00	5.00	14458.579
GROSS ULT., MB & MMF	0.000	24188.031	DISCOUNT %	10.00	8.00	11795.095
GROSS CUM., MB & MMF	0.000	0.000	UNDISCOUNTED PAYOUT, YRS.	3.40	10.00	10409.065
GROSS RES., MB & MMF	0.000	24188.031	DISCOUNTED PAYOUT, YRS.	3.44	12.00	9249.306
NET RES., MB & MMF	0.000	11943.622	UNDISCOUNTED NET/INVEST.	5.93	15.00	7830.111
NET REVENUE, M$	0.000	32225.955	DISCOUNTED NET/INVEST.	4.06	18.00	6698.377
INITIAL PRICE, $	0.000	2.430	RATE-OF-RETURN, PCT.	100.00	20.00	6065.726
INITIAL N.I., PCT.	0.000	49.953	INITIAL W.I., PCT.	56.742	30.00	3861.952
FINAL N.I., PCT.	0.000	49.063	FINAL W.I., PCT.	55.840	50.00	1810.298
					100.00	410.808

TOTAL - JUDITH RIVER RESERVOIR
NFR BEAR PAW BASIN, LLC
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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----
01-2012	7.0	0.000	16.340	0.000	8.451	0.000	1.958	0.000	16.551
12-2012	7.5	0.000	251.639	0.000	142.663	0.000	1.886	0.000	269.134
12-2013	7.2	0.000	230.037	0.000	133.707	0.000	2.183	0.000	291.875
12-2014	9.0	0.000	331.664	0.000	218.108	0.000	2.309	0.000	503.608
12-2015	13.0	0.000	609.711	0.000	280.966	0.000	2.419	0.000	679.638
12-2016	13.3	0.000	426.015	0.000	198.371	0.000	2.554	0.000	506.625
12-2017	14.0	0.000	371.368	0.000	168.903	0.000	2.690	0.000	454.281
12-2018	12.7	0.000	297.374	0.000	138.070	0.000	2.684	0.000	370.624
12-2019	12.0	0.000	251.196	0.000	117.089	0.000	2.683	0.000	314.153
12-2020	12.0	0.000	215.547	0.000	100.576	0.000	2.683	0.000	269.816
12-2021	12.0	0.000	185.367	0.000	86.495	0.000	2.683	0.000	232.039
12-2022	11.9	0.000	159.302	0.000	74.357	0.000	2.683	0.000	199.464
12-2023	11.0	0.000	135.836	0.000	63.656	0.000	2.680	0.000	170.620
12-2024	11.0	0.000	116.819	0.000	54.744	0.000	2.680	0.000	146.734
12-2025	10.2	0.000	94.026	0.000	42.855	0.000	2.691	0.000	115.301
S TOT	1.0	0.000	3692.240	0.000	1829.012	0.000	2.482	0.000	4540.462
AFTER	1.0	0.000	242.642	0.000	126.875	0.000	2.721	0.000	345.210
TOTAL	1.0	0.000	3934.883	0.000	1955.887	0.000	2.498	0.000	4885.672

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	16.551	1.533	0.000	1.454	1.454	11.250	2.314	2.314	2.261
12-2012	269.134	16.015	0.000	15.910	15.910	0.000	237.209	239.523	228.628
12-2013	291.875	22.151	0.000	17.158	17.158	271.250	-18.684	220.840	218.383
12-2014	503.608	23.451	0.000	33.066	33.066	253.119	193.972	414.812	381.157
12-2015	679.638	35.692	0.000	63.810	63.810	0.000	580.136	994.948	799.574
12-2016	506.625	44.153	0.000	65.739	65.739	4.935	391.798	1386.746	1054.772
12-2017	454.281	39.029	0.000	67.151	67.151	0.000	348.101	1734.848	1261.402
12-2018	370.624	34.320	0.000	61.942	61.942	0.000	274.362	2009.210	1409.356
12-2019	314.153	29.091	0.000	59.706	59.706	0.000	225.356	2234.566	1519.828
12-2020	269.816	24.985	0.000	59.706	59.706	0.000	185.124	2419.690	1602.332
12-2021	232.039	21.487	0.000	59.706	59.706	0.000	150.846	2570.537	1663.452
12-2022	199.464	18.470	0.000	59.624	59.624	0.000	121.369	2691.906	1708.163
12-2023	170.620	15.799	0.000	58.721	58.721	0.000	96.100	2788.005	1740.352
12-2024	146.734	13.588	0.000	58.721	58.721	0.000	74.425	2862.429	1763.019
12-2025	115.301	10.677	0.000	48.320	48.328	0.000	56.296	2918.726	1778.607
S TOT	4540.462	350.440	0.000	730.743	730.743	540.554	2918.726	2918.726	1778.607
AFTER	345.210	31.966	0.000	131.494	131.494	0.000	181.749	3100.474	1815.552
TOTAL	4885.672	382.406	0.000	862.237	862.237	540.554	3100.475	3100.474	1815.552

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	0.0	23.0	LIFE, YRS.	25.75	5.00	2320.067
GROSS ULT., MB & MMF	0.000	8330.539	DISCOUNT %	10.00	8.00	1993.385
GROSS CUM., MB & MMF	0.000	4395.657	UNDISCOUNTED PAYOUT, YRS.	0.07	10.00	1815.552
GROSS RES., MB & MMF	0.000	3934.882	DISCOUNTED PAYOUT, YRS.	0.07	12.00	1662.700
NET RES., MB & MMF	0.000	1955.887	UNDISCOUNTED NET/INVEST.	6.74	15.00	1470.725
NET REVENUE, M$	0.000	4885.672	DISCOUNTED NET/INVEST.	5.18	18.00	1313.763
INITIAL PRICE, $	0.000	1.972	RATE-OF-RETURN, PCT.	100.00	20.00	1224.490
INITIAL N.I., PCT.	0.000	52.786	INITIAL W.I., PCT.	53.728	30.00	903.797
FINAL N.I., PCT.	0.000	24.997	FINAL W.I., PCT.	32.900	50.00	583.400
					100.00	320.390

PDP - JUDITH RIVER RESERVOIR
NFR BEAR PAW BASIN, LLC
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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----
01-2012	7.0	0.000	16.340	0.000	8.451	0.000	1.958	0.000	16.551
12-2012	6.5	0.000	162.219	0.000	83.981	0.000	1.957	0.000	164.351
12-2013	6.0	0.000	149.861	0.000	77.653	0.000	2.256	0.000	175.221
12-2014	6.0	0.000	128.766	0.000	66.740	0.000	2.425	0.000	161.813
12-2015	6.0	0.000	110.739	0.000	57.396	0.000	2.547	0.000	146.176
12-2016	6.0	0.000	95.236	0.000	49.361	0.000	2.664	0.000	131.494
12-2017	6.0	0.000	81.903	0.000	42.450	0.000	2.791	0.000	118.490
12-2018	4.7	0.000	67.042	0.000	34.421	0.000	2.802	0.000	96.450
12-2019	4.0	0.000	56.324	0.000	28.772	0.000	2.807	0.000	80.773
12-2020	4.0	0.000	48.438	0.000	24.744	0.000	2.807	0.000	69.465
12-2021	4.0	0.000	41.657	0.000	21.280	0.000	2.807	0.000	59.740
12-2022	3.9	0.000	35.711	0.000	18.272	0.000	2.807	0.000	51.286
12-2023	3.0	0.000	29.548	0.000	15.423	0.000	2.800	0.000	43.188
12-2024	3.0	0.000	25.411	0.000	13.264	0.000	2.800	0.000	37.142
12-2025	3.0	0.000	21.853	0.000	11.407	0.000	2.800	0.000	31.942
S TOT	1.0	0.000	1071.048	0.000	553.615	0.000	2.500	0.000	1384.081
AFTER	1.0	0.000	98.116	0.000	53.896	0.000	2.766	0.000	149.063
TOTAL	1.0	0.000	1169.164	0.000	607.511	0.000	2.524	0.000	1533.144

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	16.551	1.533	0.000	1.454	1.454	0.000	13.564	13.564	13.511
12-2012	164.351	15.219	0.000	14.013	14.013	0.000	135.120	148.684	142.034
12-2013	175.221	16.225	0.000	13.670	13.670	0.000	145.325	294.009	268.216
12-2014	161.813	14.984	0.000	14.012	14.012	0.000	132.817	426.827	373.054
12-2015	146.176	13.536	0.000	14.362	14.362	0.000	118.278	545.105	457.929
12-2016	131.494	12.176	0.000	14.721	14.721	0.000	104.596	649.701	526.165
12-2017	118.490	10.972	0.000	14.888	14.888	0.000	92.630	742.331	581.100
12-2018	96.450	8.931	0.000	9.679	9.679	0.000	77.839	820.170	623.065
12-2019	80.773	7.480	0.000	7.444	7.444	0.000	65.850	886.020	655.339
12-2020	69.465	6.432	0.000	7.444	7.444	0.000	55.589	941.609	680.107
12-2021	59.740	5.532	0.000	7.444	7.444	0.000	46.764	988.373	699.050
12-2022	51.286	4.749	0.000	7.362	7.362	0.000	39.175	1027.548	713.477
12-2023	43.188	3.999	0.000	6.459	6.459	0.000	32.730	1060.278	724.434
12-2024	37.142	3.439	0.000	6.459	6.459	0.000	27.243	1087.521	732.726
12-2025	31.942	2.958	0.000	6.459	6.459	0.000	22.525	1110.046	738.959
S TOT	1384.081	128.166	0.000	145.869	145.869	0.000	1110.046	1110.046	738.959
AFTER	149.063	13.803	0.000	58.304	58.304	0.000	76.956	1187.003	754.621
TOTAL	1533.144	141.969	0.000	204.172	204.172	0.000	1187.003	1187.003	754.621

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	0.0	15.0	LIFE, YRS.	24.92	5.00	923.951
GROSS ULT., MB & MMF	0.000	5564.821	DISCOUNT %	10.00	8.00	814.334
GROSS CUM., MB & MMF	0.000	4395.657	UNDISCOUNTED PAYOUT, YRS.	0.00	10.00	754.621
GROSS RES., MB & MMF	0.000	1169.164	DISCOUNTED PAYOUT, YRS.	0.00	12.00	703.182
NET RES., MB & MMF	0.000	607.511	UNDISCOUNTED NET/INVEST.	0.00	15.00	638.285
NET REVENUE, M$	0.000	1533.144	DISCOUNTED NET/INVEST.	0.00	18.00	584.816
INITIAL PRICE, $	0.000	0.000	RATE-OF-RETURN, PCT.	100.00	20.00	554.161
INITIAL N.I., PCT.	0.000	52.786	INITIAL W.I., PCT.	0.000	30.00	441.555
FINAL N.I., PCT.	0.000	67.500	FINAL W.I., PCT.	100.000	50.00	320.956
					100.00	204.691

PDNP - JUDITH RIVER RESERVOIR
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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

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--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF----	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$-----	NET GAS SALES -----M$-----
01-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	1.0	0.000	89.421	0.000	58.682	0.000	1.786	0.000	104.783
12-2013	1.0	0.000	48.744	0.000	31.988	0.000	2.060	0.000	65.894
12-2014	1.0	0.000	36.343	0.000	23.850	0.000	2.213	0.000	52.790
12-2015	1.0	0.000	30.067	0.000	19.731	0.000	2.325	0.000	45.875
12-2016	1.3	0.000	71.799	0.000	28.427	0.000	2.591	0.000	73.644
12-2017	2.0	0.000	88.208	0.000	31.062	0.000	2.767	0.000	85.935
12-2018	2.0	0.000	61.359	0.000	23.089	0.000	2.736	0.000	63.178
12-2019	2.0	0.000	49.721	0.000	19.094	0.000	2.727	0.000	52.079
12-2020	2.0	0.000	42.279	0.000	16.301	0.000	2.726	0.000	44.432
12-2021	2.0	0.000	36.357	0.000	14.018	0.000	2.726	0.000	38.209
12-2022	2.0	0.000	31.267	0.000	12.055	0.000	2.726	0.000	32.860
12-2023	2.0	0.000	26.889	0.000	10.368	0.000	2.726	0.000	28.260
12-2024	2.0	0.000	23.125	0.000	8.916	0.000	2.726	0.000	24.303
12-2025	2.0	0.000	19.887	0.000	7.668	0.000	2.726	0.000	20.901
S TOT	1.0	0.000	655.465	0.000	305.250	0.000	2.402	0.000	733.144
AFTER	1.0	0.000	94.498	0.000	34.567	0.000	2.749	0.000	95.023
TOTAL	1.0	0.000	749.963	0.000	339.817	0.000	2.437	0.000	828.167

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	0.000	0.000	0.000	0.000	0.000	11.250	-11.250	-11.250	-11.250
12-2012	104.783	0.796	0.000	1.898	1.898	0.000	102.089	90.839	86.594
12-2013	65.894	5.540	0.000	2.098	2.098	0.000	58.256	149.096	137.286
12-2014	52.790	4.888	0.000	2.150	2.150	0.000	45.751	194.847	173.418
12-2015	45.875	4.248	0.000	2.204	2.204	0.000	39.423	234.270	201.707
12-2016	73.644	4.059	0.000	2.592	2.592	4.935	62.058	296.328	241.576
12-2017	85.935	4.920	0.000	3.287	3.287	0.000	77.727	374.055	287.803
12-2018	63.178	5.850	0.000	3.287	3.287	0.000	54.041	428.096	316.953
12-2019	52.079	4.823	0.000	3.287	3.287	0.000	43.970	472.065	338.505
12-2020	44.432	4.114	0.000	3.287	3.287	0.000	37.030	509.096	355.004
12-2021	38.209	3.538	0.000	3.287	3.287	0.000	31.384	540.480	367.716
12-2022	32.860	3.043	0.000	3.287	3.287	0.000	26.530	567.010	377.485
12-2023	28.260	2.617	0.000	3.287	3.287	0.000	22.356	589.365	384.969
12-2024	24.303	2.250	0.000	3.287	3.287	0.000	18.766	608.131	390.680
12-2025	20.901	1.935	0.000	3.287	3.287	0.000	15.678	623.809	395.018
S TOT	733.144	52.623	0.000	40.527	40.527	16.185	623.809	623.809	395.018
AFTER	95.023	8.799	0.000	28.152	28.152	0.000	58.072	681.881	406.627
TOTAL	828.167	61.422	0.000	68.679	68.679	16.185	681.881	681.881	406.627

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	0.0	2.0	LIFE, YRS.	25.75	5.00	512.186
GROSS ULT., MB & MMF	0.000	749.963	DISCOUNT %	10.00	8.00	443.451
GROSS CUM., MB & MMF	0.000	0.000	UNDISCOUNTED PAYOUT, YRS.	0.18	10.00	406.627
GROSS RES., MB & MMF	0.000	749.963	DISCOUNTED PAYOUT, YRS.	0.19	12.00	375.309
NET RES., MB & MMF	0.000	339.817	UNDISCOUNTED NET/INVEST.	43.13	15.00	336.400
NET REVENUE, M$	0.000	828.167	DISCOUNTED NET/INVEST.	29.16	18.00	304.917
INITIAL PRICE, $	0.000	2.305	RATE-OF-RETURN, PCT.	100.00	20.00	287.130
INITIAL N.I., PCT.	0.000	65.625	INITIAL W.I., PCT.	49.207	30.00	223.740
FINAL N.I., PCT.	0.000	24.997	FINAL W.I., PCT.	32.900	50.00	160.094
					100.00	103.652

PRB - JUDITH RIVER RESERVOIR
NFR BEAR PAW BASIN, LLC
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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

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--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----
01-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2013	0.2	0.000	31.433	0.000	24.066	0.000	2.109	0.000	50.760
12-2014	2.0	0.000	166.555	0.000	127.519	0.000	2.266	0.000	289.005
12-2015	2.0	0.000	91.669	0.000	70.184	0.000	2.381	0.000	167.084
12-2016	2.0	0.000	70.083	0.000	53.657	0.000	2.490	0.000	133.614
12-2017	2.0	0.000	58.557	0.000	44.833	0.000	2.609	0.000	116.976
12-2018	2.0	0.000	50.307	0.000	38.516	0.000	2.609	0.000	100.496
12-2019	2.0	0.000	43.264	0.000	33.124	0.000	2.609	0.000	86.427
12-2020	2.0	0.000	37.207	0.000	28.487	0.000	2.609	0.000	74.327
12-2021	2.0	0.000	31.998	0.000	24.499	0.000	2.609	0.000	63.921
12-2022	2.0	0.000	27.518	0.000	21.069	0.000	2.609	0.000	54.972
12-2023	2.0	0.000	23.666	0.000	18.119	0.000	2.609	0.000	47.276
12-2024	2.0	0.000	20.353	0.000	15.582	0.000	2.609	0.000	40.657
12-2025	1.2	0.000	11.065	0.000	9.176	0.000	2.624	0.000	24.076
S TOT	1.0	0.000	663.673	0.000	508.829	0.000	2.456	0.000	1249.591
AFTER	1.0	0.000	39.926	0.000	34.935	0.000	2.633	0.000	91.989
TOTAL	1.0	0.000	703.599	0.000	543.765	0.000	2.467	0.000	1341.580

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2013	50.760	0.386	0.000	1.390	1.390	271.250	-222.265	-222.265	-187.119
12-2014	289.005	3.578	0.000	16.903	16.903	0.000	268.523	46.257	26.375
12-2015	167.084	15.472	0.000	17.326	17.326	0.000	134.286	180.543	122.901
12-2016	133.614	12.373	0.000	17.759	17.759	0.000	103.482	284.026	190.449
12-2017	116.976	10.832	0.000	17.961	17.961	0.000	88.184	372.209	242.753
12-2018	100.496	9.306	0.000	17.961	17.961	0.000	73.229	445.439	282.239
12-2019	86.427	8.003	0.000	17.961	17.961	0.000	60.463	505.901	311.878
12-2020	74.327	6.883	0.000	17.961	17.961	0.000	49.483	555.385	333.932
12-2021	63.921	5.919	0.000	17.961	17.961	0.000	40.041	595.426	350.158
12-2022	54.972	5.090	0.000	17.961	17.961	0.000	31.921	627.347	361.918
12-2023	47.276	4.378	0.000	17.961	17.961	0.000	24.938	652.284	370.272
12-2024	40.657	3.765	0.000	17.961	17.961	0.000	18.932	671.216	376.039
12-2025	24.076	2.229	0.000	7.568	7.568	0.000	14.279	685.495	379.991
S TOT	1249.591	88.214	0.000	204.633	204.633	271.250	685.495	685.495	379.991
AFTER	91.989	8.518	0.000	36.932	36.932	0.000	46.539	732.034	389.618
TOTAL	1341.580	96.732	0.000	241.564	241.564	271.250	732.034	732.034	389.618

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	0.0	2.0	LIFE, YRS.	23.00	5.00	524.335
GROSS ULT., MB & MMF	0.000	703.599	DISCOUNT %	10.00	8.00	437.122
GROSS CUM., MB & MMF	0.000	0.000	UNDISCOUNTED PAYOUT, YRS.	2.83	10.00	389.618
GROSS RES., MB & MMF	0.000	703.599	DISCOUNTED PAYOUT, YRS.	2.88	12.00	348.794
NET RES., MB & MMF	0.000	543.765	UNDISCOUNTED NET/INVEST.	3.70	15.00	297.569
NET REVENUE, M$	0.000	1341.580	DISCOUNTED NET/INVEST.	2.71	18.00	255.774
INITIAL PRICE, $	0.000	2.106	RATE-OF-RETURN, PCT.	100.00	20.00	232.063
INITIAL N.I., PCT.	0.000	76.563	INITIAL W.I., PCT.	87.634	30.00	147.615
FINAL N.I., PCT.	0.000	87.500	FINAL W.I., PCT.	100.000	50.00	66.235
					100.00	8.516

POS - JUDITH RIVER RESERVOIR
NFR BEAR PAW BASIN, LLC
MONTANA

DATE : 12/27/2011
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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$-----	NET GAS SALES -----M$-----
01-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2013	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2014	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2015	4.0	0.000	377.236	0.000	133.655	0.000	2.398	0.000	320.504
12-2016	4.0	0.000	188.898	0.000	66.927	0.000	2.508	0.000	167.873
12-2017	4.0	0.000	142.701	0.000	50.559	0.000	2.628	0.000	132.880
12-2018	4.0	0.000	118.667	0.000	42.044	0.000	2.628	0.000	110.500
12-2019	4.0	0.000	101.886	0.000	36.098	0.000	2.628	0.000	94.874
12-2020	4.0	0.000	87.622	0.000	31.045	0.000	2.628	0.000	81.592
12-2021	4.0	0.000	75.355	0.000	26.698	0.000	2.628	0.000	70.169
12-2022	4.0	0.000	64.805	0.000	22.961	0.000	2.628	0.000	60.345
12-2023	4.0	0.000	55.733	0.000	19.746	0.000	2.628	0.000	51.897
12-2024	4.0	0.000	47.930	0.000	16.982	0.000	2.628	0.000	44.631
12-2025	4.0	0.000	41.220	0.000	14.604	0.000	2.628	0.000	38.383
S TOT	3.2	0.000	1302.054	0.000	461.318	0.000	2.544	0.000	1173.647
AFTER	3.2	0.000	10.102	0.000	3.477	0.000	2.627	0.000	9.134
TOTAL	3.2	0.000	1312.156	0.000	464.795	0.000	2.545	0.000	1182.781

--END-- MO-YEAR	TOT NET REVENUE -----M$-----	NET PROD TAXES -----M$-----	NET ADVAL TAXES -----M$-----	OPERATING EXPENSE -----M$-----	TOTAL EXPENSE -----M$-----	CAPITAL INVESTMENT -----M$-----	FUTURE NET CASHFLOW -----M$-----	CUMUL NET CASHFLOW -----M$-----	10.0% CUM DISC CF -----M$-----
01-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2013	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2014	0.000	0.000	0.000	0.000	0.000	253.119	-253.119	-253.119	-191.689
12-2015	320.504	2.436	0.000	29.918	29.918	0.000	288.150	35.030	17.037
12-2016	167.873	15.545	0.000	30.666	30.666	0.000	121.661	156.692	96.581
12-2017	132.880	12.305	0.000	31.014	31.014	0.000	89.561	246.252	149.745
12-2018	110.500	10.232	0.000	31.014	31.014	0.000	69.253	315.505	187.099
12-2019	94.874	8.785	0.000	31.014	31.014	0.000	55.074	370.580	214.105
12-2020	81.592	7.555	0.000	31.014	31.014	0.000	43.022	413.602	233.288
12-2021	70.169	6.498	0.000	31.014	31.014	0.000	32.657	446.258	246.529
12-2022	60.345	5.588	0.000	31.014	31.014	0.000	23.743	470.001	255.284
12-2023	51.897	4.806	0.000	31.014	31.014	0.000	16.077	486.078	260.677
12-2024	44.631	4.133	0.000	31.014	31.014	0.000	9.484	495.562	263.574
12-2025	38.383	3.554	0.000	31.014	31.014	0.000	3.814	499.376	264.639
S TOT	1173.647	81.437	0.000	339.714	339.714	253.119	499.376	499.376	264.639
AFTER	9.134	0.846	0.000	8.107	8.107	0.000	0.181	499.557	264.686
TOTAL	1182.781	02.283	0.000	347.821	347.821	253.119	499.557	499.557	264.686

	OIL	GAS
GROSS WELLS	0.0	4.0
GROSS ULT., MB & MMF	0.000	1312.156
GROSS CUM., MB & MMF	0.000	0.000
GROSS RES., MB & MMF	0.000	1312.156
NET RES., MB & MMF	0.000	464.795
NET REVENUE, M$	0.000	1182.781
INITIAL PRICE, $	0.000	2.390
INITIAL N.I., PCT.	0.000	35.430
FINAL N.I., PCT.	0.000	34.419

LIFE, YRS.	14.33
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	3.88
DISCOUNTED PAYOUT, YRS.	3.92
UNDISCOUNTED NET/INVEST.	2.97
DISCOUNTED NET/INVEST.	2.38
RATE-OF-RETURN, PCT.	100.00
INITIAL W.I., PCT.	40.967
FINAL W.I., PCT.	39.606

P.W. %	P.W., M$
5.00	359.594
8.00	298.479
10.00	264.686
12.00	235.415
15.00	198.472
18.00	168.257
20.00	151.136
30.00	90.887
50.00	36.114
100.00	3.532

TOTAL - NIOBRARA RESERVOIR
NFR BEAR PAW BASIN, LLC
MONTANA

DATE : 12/27/2011
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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----
01-2012	95.0	0.000	70.856	0.000	43.252	0.000	1.887	0.000	81.606
12-2012	98.1	0.000	2626.671	0.000	1535.385	0.000	1.857	0.000	2851.763
12-2013	143.5	0.000	6153.185	0.000	3686.136	0.000	2.136	0.000	7874.625
12-2014	169.8	0.000	5550.194	0.000	3166.648	0.000	2.298	0.000	7276.754
12-2015	176.5	0.000	3345.289	0.000	1968.340	0.000	2.418	0.000	4759.841
12-2016	170.6	0.000	1960.606	0.000	1150.886	0.000	2.535	0.000	2916.921
12-2017	164.6	0.000	1426.379	0.000	837.542	0.000	2.660	0.000	2227.770
12-2018	161.6	0.000	1125.746	0.000	661.084	0.000	2.664	0.000	1761.037
12-2019	156.8	0.000	924.218	0.000	542.620	0.000	2.668	0.000	1447.499
12-2020	153.7	0.000	784.107	0.000	460.210	0.000	2.671	0.000	1229.079
12-2021	151.1	0.000	678.980	0.000	398.325	0.000	2.673	0.000	1064.891
12-2022	146.4	0.000	586.430	0.000	343.147	0.000	2.676	0.000	918.291
12-2023	142.8	0.000	516.684	0.000	301.823	0.000	2.679	0.000	808.439
12-2024	139.4	0.000	461.358	0.000	269.284	0.000	2.681	0.000	721.939
12-2025	135.7	0.000	414.888	0.000	242.395	0.000	2.682	0.000	650.133
S TOT	4.6	0.000	26625.590	0.000	15607.078	0.000	2.344	0.000	36590.594
AFTER	4.6	0.000	2034.171	0.000	1179.853	0.000	2.737	0.000	3229.113
TOTAL	4.6	0.000	28659.760	0.000	16786.932	0.000	2.372	0.000	39819.703

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	81.606	7.563	0.000	18.592	18.592	0.000	55.452	55.452	55.232
12-2012	2851.763	89.434	0.000	210.370	210.370	8419.164	-5867.204	-5811.752	-5426.342
12-2013	7874.625	172.358	0.000	347.222	347.222	4543.000	2812.045	-2999.707	-2934.742
12-2014	7276.754	327.394	0.000	417.776	417.776	3557.454	2974.130	-25.576	-588.660
12-2015	4759.841	326.256	0.000	456.521	456.521	0.000	3977.065	3951.489	2281.724
12-2016	2916.921	270.155	0.000	452.711	452.711	0.000	2194.055	6145.544	3716.155
12-2017	2227.770	206.339	0.000	442.877	442.877	0.000	1578.554	7724.098	4653.494
12-2018	1761.037	163.117	0.000	433.037	433.037	0.000	1164.883	8888.981	5282.051
12-2019	1447.499	134.080	0.000	417.332	417.332	0.000	896.086	9785.067	5721.505
12-2020	1229.079	113.852	0.000	408.732	408.732	0.000	706.495	10491.562	6036.438
12-2021	1064.891	98.646	0.000	401.572	401.572	0.000	564.673	11056.235	6265.251
12-2022	918.291	85.069	0.000	377.581	377.581	0.000	455.642	11511.877	6433.085
12-2023	808.439	74.894	0.000	362.714	362.714	0.000	370.830	11882.707	6557.256
12-2024	721.939	66.882	0.000	353.092	353.092	0.000	301.965	12184.672	6649.178
12-2025	650.133	60.217	0.000	344.870	344.870	0.000	245.047	12429.719	6716.995
S TOT	36590.594	2196.259	0.000	5444.999	5444.999	16519.617	12429.719	12429.719	6716.995
AFTER	3229.113	299.016	0.000	1775.526	1775.526	0.000	1154.570	13584.290	6913.042
TOTAL	39819.703	2495.274	0.000	7220.525	7220.525	16519.617	13584.289	13584.290	6913.042

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	0.0	217.0	LIFE, YRS.	34.67	5.00	9530.633
GROSS ULT., MB & MMF	0.000	48124.609	DISCOUNT %	10.00	8.00	7839.611
GROSS CUM., MB & MMF	0.000	19464.850	UNDISCOUNTED PAYOUT, YRS.	0.00	10.00	6913.042
GROSS RES., MB & MMF	0.000	28659.758	DISCOUNTED PAYOUT, YRS.	0.00	12.00	6110.693
NET RES., MB & MMF	0.000	16786.932	UNDISCOUNTED NET/INVEST.	1.82	15.00	5092.292
NET REVENUE, M$	0.000	39819.699	DISCOUNTED NET/INVEST.	1.47	18.00	4248.370
INITIAL PRICE, $	0.000	2.000	RATE-OF-RETURN, PCT.	55.18	20.00	3763.004
INITIAL N.I., PCT.	0.000	61.159	INITIAL W.I., PCT.	67.280	30.00	1981.612
FINAL N.I., PCT.	0.000	58.112	FINAL W.I., PCT.	66.211	50.00	147.148
					100.00	-1272.218

PDP - NIOBRARA RESERVOIR
NFR BEAR PAW BASIN, LLC
MONTANA

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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----
01-2012	95.0	0.000	70.856	0.000	43.252	0.000	1.887	0.000	81.606
12-2012	87.4	0.000	691.917	0.000	421.478	0.000	1.890	0.000	796.679
12-2013	82.0	0.000	628.601	0.000	381.842	0.000	2.186	0.000	834.781
12-2014	79.5	0.000	533.781	0.000	323.693	0.000	2.354	0.000	761.890
12-2015	74.5	0.000	458.124	0.000	277.168	0.000	2.477	0.000	686.658
12-2016	68.6	0.000	396.007	0.000	238.778	0.000	2.596	0.000	619.978
12-2017	62.6	0.000	345.594	0.000	207.908	0.000	2.725	0.000	566.632
12-2018	59.6	0.000	306.857	0.000	184.103	0.000	2.731	0.000	502.744
12-2019	54.8	0.000	269.784	0.000	161.446	0.000	2.738	0.000	442.003
12-2020	51.7	0.000	242.241	0.000	144.601	0.000	2.743	0.000	396.568
12-2021	49.1	0.000	218.745	0.000	130.258	0.000	2.747	0.000	357.804
12-2022	46.5	0.000	197.281	0.000	117.123	0.000	2.752	0.000	322.317
12-2023	43.8	0.000	178.375	0.000	105.605	0.000	2.757	0.000	291.153
12-2024	40.4	0.000	160.153	0.000	94.573	0.000	2.764	0.000	261.353
12-2025	36.7	0.000	144.027	0.000	85.273	0.000	2.767	0.000	235.921
S TOT	4.6	0.000	4842.341	0.000	2917.100	0.000	2.454	0.000	7158.087
AFTER	4.6	0.000	1123.374	0.000	665.144	0.000	2.813	0.000	1871.215
TOTAL	4.6	0.000	5965.716	0.000	3582.244	0.000	2.521	0.000	9029.302

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	81.606	7.563	0.000	18.592	18.592	0.000	55.452	55.452	55.232
12-2012	796.679	73.816	0.000	189.154	189.154	0.000	533.709	589.161	563.125
12-2013	834.781	77.350	0.000	198.119	198.119	0.000	559.312	1148.473	1048.986
12-2014	761.890	70.601	0.000	196.095	196.095	0.000	495.194	1643.666	1439.991
12-2015	686.658	63.634	0.000	190.217	190.217	0.000	432.807	2076.473	1750.630
12-2016	619.978	57.458	0.000	179.750	179.750	0.000	382.770	2459.243	2000.348
12-2017	566.632	52.518	0.000	166.817	166.817	0.000	347.298	2806.541	2206.283
12-2018	502.744	46.599	0.000	156.977	156.977	0.000	299.168	3105.709	2367.542
12-2019	442.003	40.972	0.000	141.272	141.272	0.000	259.760	3365.469	2494.821
12-2020	396.568	36.762	0.000	132.672	132.672	0.000	227.134	3592.603	2595.993
12-2021	357.804	33.170	0.000	125.512	125.512	0.000	199.122	3791.726	2676.624
12-2022	322.317	29.882	0.000	117.223	117.223	0.000	175.213	3966.938	2741.121
12-2023	291.153	26.994	0.000	109.265	109.265	0.000	154.894	4121.832	2792.952
12-2024	261.353	24.232	0.000	99.643	99.643	0.000	137.478	4259.310	2834.772
12-2025	235.921	21.861	0.000	91.421	91.421	0.000	122.639	4381.949	2868.686
S TOT	7158.087	663.410	0.000	2112.729	2112.729	0.000	4381.949	4381.949	2868.686
AFTER	1871.215	173.275	0.000	764.841	764.841	0.000	933.100	5315.048	3014.921
TOTAL	9029.302	836.684	0.000	2877.571	2877.571	0.000	5315.048	5315.048	3014.921

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	0.0	115.0	LIFE, YRS.	34.67	5.00	3831.403
GROSS ULT., MB & MMF	0.000	25430.566	DISCOUNT %	10.00	8.00	3292.212
GROSS CUM., MB & MMF	0.000	19464.850	UNDISCOUNTED PAYOUT, YRS.	0.00	10.00	3014.920
GROSS RES., MB & MMF	0.000	5965.716	DISCOUNTED PAYOUT, YRS.	0.00	12.00	2784.324
NET RES., MB & MMF	0.000	3582.244	UNDISCOUNTED NET/INVEST.	0.00	15.00	2503.173
NET REVENUE, M$	0.000	9029.304	DISCOUNTED NET/INVEST.	0.00	18.00	2278.782
INITIAL PRICE, $	0.000	0.000	RATE-OF-RETURN, PCT.	100.00	20.00	2152.741
INITIAL N.I., PCT.	0.000	61.159	INITIAL W.I., PCT.	0.000	30.00	1703.137
FINAL N.I., PCT.	0.000	58.112	FINAL W.I., PCT.	66.211	50.00	1238.142
					100.00	796.868

PUD - NIOBRARA RESERVOIR
NFR BEAR PAW BASIN, LLC
MONTANA

DATE : 12/27/2011
TIME : 10:22:35
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SETUP FILE : TOGAC

THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----
01-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	10.7	0.000	1934.754	0.000	1113.907	0.000	1.845	0.000	2055.085
12-2013	60.2	0.000	5458.961	0.000	3269.483	0.000	2.131	0.000	6965.761
12-2014	68.0	0.000	2249.420	0.000	1340.013	0.000	2.290	0.000	3069.221
12-2015	68.0	0.000	1223.791	0.000	728.495	0.000	2.405	0.000	1752.307
12-2016	68.0	0.000	822.849	0.000	489.587	0.000	2.516	0.000	1231.712
12-2017	68.0	0.000	610.657	0.000	363.222	0.000	2.636	0.000	957.437
12-2018	68.0	0.000	480.522	0.000	285.755	0.000	2.636	0.000	753.219
12-2019	68.0	0.000	393.187	0.000	233.783	0.000	2.636	0.000	616.214
12-2020	68.0	0.000	330.864	0.000	196.703	0.000	2.636	0.000	518.470
12-2021	68.0	0.000	284.354	0.000	169.037	0.000	2.636	0.000	445.542
12-2022	68.0	0.000	248.441	0.000	147.677	0.000	2.636	0.000	389.239
12-2023	68.0	0.000	219.953	0.000	130.735	0.000	2.636	0.000	344.583
12-2024	68.0	0.000	196.857	0.000	117.001	0.000	2.636	0.000	308.383
12-2025	68.0	0.000	177.792	0.000	105.666	0.000	2.636	0.000	278.503
S TOT	1.0	0.000	14632.402	0.000	8691.064	0.000	2.265	0.000	19685.674
AFTER	1.0	0.000	488.379	0.000	287.006	0.000	2.638	0.000	757.160
TOTAL	1.0	0.000	15120.781	0.000	8978.070	0.000	2.277	0.000	20442.834

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	2055.085	15.619	0.000	21.216	21.216	8419.164	-6400.913	-6400.913	-5989.468
12-2013	6965.761	94.445	0.000	148.648	148.648	2839.097	3883.571	-2517.342	-2622.024
12-2014	3069.221	229.456	0.000	172.613	172.613	0.000	2667.153	149.811	-504.904
12-2015	1752.307	162.264	0.000	176.928	176.928	0.000	1413.116	1562.927	511.960
12-2016	1231.712	114.057	0.000	181.352	181.352	0.000	936.304	2499.230	1123.887
12-2017	957.437	88.659	0.000	183.411	183.411	0.000	685.368	3184.598	1530.864
12-2018	753.219	69.748	0.000	183.411	183.411	0.000	500.060	3684.658	1800.731
12-2019	616.214	57.061	0.000	183.411	183.411	0.000	375.741	4060.399	1985.040
12-2020	518.470	48.010	0.000	183.411	183.411	0.000	287.049	4347.448	2113.033
12-2021	445.542	41.257	0.000	183.411	183.411	0.000	220.874	4568.322	2202.563
12-2022	309.239	36.044	0.000	183.411	183.411	0.000	169.785	4738.107	2265.131
12-2023	344.583	31.908	0.000	183.411	183.411	0.000	129.263	4867.371	2308.440
12-2024	308.383	28.556	0.000	183.411	183.411	0.000	96.416	4963.786	2337.814
12-2025	278.503	25.789	0.000	183.411	183.411	0.000	69.303	5033.089	2357.015
S TOT	19685.674	1042.874	0.000	2351.454	2351.454	11258.261	5033.089	5033.089	2357.015
AFTER	757.160	70.113	0.000	590.371	590.371	0.000	96.675	5129.765	2379.485
TOTAL	20442.834	1112.987	0.000	2941.826	2941.826	11258.261	5129.765	5129.765	2379.485

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	0.0	68.0	LIFE, YRS.	21.42	5.00	3528.496
GROSS ULT., MB & MMF	0.000	15120.782	DISCOUNT %	10.00	8.00	2796.747
GROSS CUM., MB & MMF	0.000	0.000	UNDISCOUNTED PAYOUT, YRS.	2.94	10.00	2379.484
GROSS RES., MB & MMF	0.000	15120.782	DISCOUNTED PAYOUT, YRS.	3.50	12.00	2008.744
NET RES., MB & MMF	0.000	8978.070	UNDISCOUNTED NET/INVEST.	1.46	15.00	1525.458
NET REVENUE, M$	0.000	20442.834	DISCOUNTED NET/INVEST.	1.23	18.00	1114.027
INITIAL PRICE, $	0.000	1.960	RATE-OF-RETURN, PCT.	29.54	20.00	872.815
INITIAL N.I., PCT.	0.000	57.788	INITIAL W.I., PCT.	69.089	30.00	-42.516
FINAL N.I., PCT.	0.000	49.910	FINAL W.I., PCT.	59.451	50.00	-1039.260
					100.00	-1843.635

PRB - NIOBRARA RESERVOIR
NFR BEAR PAW BASIN, LLC
MONTANA

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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----
01-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2013	0.2	0.000	65.622	0.000	34.811	0.000	2.128	0.000	74.084
12-2014	22.2	0.000	2766.993	0.000	1502.942	0.000	2.293	0.000	3445.644
12-2015	30.0	0.000	1224.238	0.000	691.117	0.000	2.411	0.000	1665.995
12-2016	30.0	0.000	613.904	0.000	343.462	0.000	2.521	0.000	865.805
12-2017	30.0	0.000	398.552	0.000	222.151	0.000	2.641	0.000	586.713
12-2018	30.0	0.000	289.961	0.000	161.291	0.000	2.641	0.000	425.956
12-2019	30.0	0.000	225.258	0.000	125.136	0.000	2.641	0.000	330.462
12-2020	30.0	0.000	182.666	0.000	101.383	0.000	2.641	0.000	267.728
12-2021	30.0	0.000	152.691	0.000	84.690	0.000	2.641	0.000	223.641
12-2022	28.2	0.000	122.734	0.000	67.291	0.000	2.638	0.000	177.540
12-2023	28.0	0.000	105.778	0.000	57.863	0.000	2.638	0.000	152.642
12-2024	28.0	0.000	93.360	0.000	51.053	0.000	2.638	0.000	134.678
12-2025	28.0	0.000	83.342	0.000	45.564	0.000	2.638	0.000	120.195
S TOT	8.8	0.000	6325.101	0.000	3488.753	0.000	2.428	0.000	8471.084
AFTER	8.8	0.000	382.968	0.000	204.168	0.000	2.639	0.000	538.769
TOTAL	8.8	0.000	6708.069	0.000	3692.921	0.000	2.440	0.000	9009.853

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2013	74.084	0.563	0.000	0.455	0.455	1703.903	-1630.837	-1630.837	-1361.705
12-2014	3445.644	27.338	0.000	49.068	49.068	2866.597	502.641	-1128.196	-1000.557
12-2015	1665.995	95.381	0.000	74.219	74.219	0.000	1496.395	368.199	80.731
12-2016	865.805	80.174	0.000	76.074	76.074	0.000	709.557	1077.756	545.077
12-2017	586.713	54.330	0.000	76.938	76.938	0.000	455.445	1533.202	815.715
12-2018	425.956	39.443	0.000	76.938	76.938	0.000	309.574	1842.776	982.852
12-2019	330.462	30.601	0.000	76.938	76.938	0.000	222.923	2065.698	1092.228
12-2020	267.728	24.792	0.000	76.938	76.938	0.000	165.998	2231.697	1166.256
12-2021	223.641	20.709	0.000	76.938	76.938	0.000	125.994	2357.691	1217.331
12-2022	177.540	16.440	0.000	63.748	63.748	0.000	97.352	2455.042	1253.199
12-2023	152.642	14.135	0.000	61.864	61.864	0.000	76.644	2531.686	1278.870
12-2024	134.678	12.471	0.000	61.864	61.864	0.000	60.343	2592.029	1297.244
12-2025	120.195	11.130	0.000	61.864	61.864	0.000	47.201	2639.230	1310.311
S TOT	8471.084	427.506	0.000	833.847	833.847	4570.500	2639.230	2639.230	1310.311
AFTER	538.769	49.890	0.000	376.642	376.642	0.000	112.238	2751.467	1334.875
TOTAL	9009.853	477.396	0.000	1210.489	1210.489	4570.500	2751.467	2751.467	1334.875

	OIL	GAS
GROSS WELLS	0.0	30.0
GROSS ULT., MB & MMF	0.000	6708.068
GROSS CUM., MB & MMF	0.000	0.000
GROSS RES., MB & MMF	0.000	6708.068
NET RES., MB & MMF	0.000	3692.921
NET REVENUE, M$	0.000	9009.854
INITIAL PRICE, $	0.000	2.293
INITIAL N.I., PCT.	0.000	53.427
FINAL N.I., PCT.	0.000	51.294

LIFE, YRS.	21.75
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	3.75
DISCOUNTED PAYOUT, YRS.	3.93
UNDISCOUNTED NET/INVEST.	1.60
DISCOUNTED NET/INVEST.	1.36
RATE-OF-RETURN, PCT.	45.96
INITIAL W.I., PCT.	63.102
FINAL W.I., PCT.	57.452

P.W. %	P.W., M$
5.00	1905.186
8.00	1537.897
10.00	1334.875
12.00	1158.844
15.00	936.199
18.00	753.490
20.00	649.650
30.00	282.296
50.00	-49.585
100.00	-208.358

POS - NIOBRARA RESERVOIR
NER BEAR PAW BASIN, LLC
MONTANA

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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----
01-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2013	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2014	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2015	4.0	0.000	439.136	0.000	271.561	0.000	2.412	0.000	654.881
12-2016	4.0	0.000	127.846	0.000	79.060	0.000	2.522	0.000	199.426
12-2017	4.0	0.000	71.575	0.000	44.262	0.000	2.643	0.000	116.987
12-2018	4.0	0.000	48.406	0.000	29.934	0.000	2.643	0.000	79.118
12-2019	4.0	0.000	35.988	0.000	22.255	0.000	2.643	0.000	58.820
12-2020	4.0	0.000	28.336	0.000	17.523	0.000	2.643	0.000	46.314
12-2021	4.0	0.000	23.190	0.000	14.341	0.000	2.643	0.000	37.903
12-2022	3.7	0.000	17.974	0.000	11.057	0.000	2.640	0.000	29.195
12-2023	3.0	0.000	12.578	0.000	7.619	0.000	2.633	0.000	20.061
12-2024	3.0	0.000	10.988	0.000	6.656	0.000	2.633	0.000	17.526
12-2025	3.0	0.000	9.727	0.000	5.892	0.000	2.633	0.000	15.515
S TOT	1.0	0.000	825.744	0.000	510.160	0.000	2.501	0.000	1275.746
AFTER	1.0	0.000	39.449	0.000	23.536	0.000	2.633	0.000	61.968
TOTAL	1.0	0.000	865.193	0.000	533.696	0.000	2.507	0.000	1337.714

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2013	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2014	0.000	0.000	0.000	0.000	0.000	690.857	-690.857	-690.857	-523.190
12-2015	654.881	4.977	0.000	15.156	15.156	0.000	634.748	-56.109	-61.598
12-2016	199.426	18.467	0.000	15.535	15.535	0.000	165.425	109.315	46.842
12-2017	116.987	10.833	0.000	15.711	15.711	0.000	90.443	199.758	100.631
12-2018	79.118	7.326	0.000	15.711	15.711	0.000	56.081	255.839	130.927
12-2019	58.820	5.447	0.000	15.711	15.711	0.000	37.662	293.501	149.415
12-2020	46.314	4.289	0.000	15.711	15.711	0.000	26.314	319.815	161.156
12-2021	37.903	3.510	0.000	15.711	15.711	0.000	18.682	338.497	168.733
12-2022	29.195	2.703	0.000	13.199	13.199	0.000	13.293	351.790	173.634
12-2023	20.061	1.858	0.000	8.174	8.174	0.000	10.030	361.819	176.994
12-2024	17.526	1.623	0.000	8.174	8.174	0.000	7.729	369.548	179.348
12-2025	15.515	1.437	0.000	8.174	8.174	0.000	5.904	375.452	180.983
S TOT	1275.746	62.469	0.000	146.968	146.968	690.857	375.452	375.452	180.983
AFTER	61.968	5.738	0.000	43.672	43.672	0.000	12.558	388.010	183.763
TOTAL	1337.714	68.207	0.000	190.640	190.640	690.857	388.010	388.010	183.763

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	0.0	4.0	LIFE, YRS.	22.17	5.00	265.548
GROSS ULT., MB & MMF	0.000	865.193	DISCOUNT %	10.00	8.00	212.755
GROSS CUM., MB & MMF	0.000	0.000	UNDISCOUNTED PAYOUT, YRS.	4.34	10.00	183.763
GROSS RES., MB & MMF	0.000	865.193	DISCOUNTED PAYOUT, YRS.	4.57	12.00	158.781
NET RES., MB & MMF	0.000	533.696	UNDISCOUNTED NET/INVEST.	1.56	15.00	127.462
NET REVENUE, M$	0.000	1337.714	DISCOUNTED NET/INVEST.	1.35	18.00	102.069
INITIAL PRICE, $	0.000	2.411	RATE-OF-RETURN, PCT.	48.52	20.00	87.799
INITIAL N.I., PCT.	0.000	61.950	INITIAL W.I., PCT.	71.992	30.00	38.695
FINAL N.I., PCT.	0.000	55.000	FINAL W.I., PCT.	62.857	50.00	-2.150
					100.00	-17.093

TOTAL - SAWTOOTH RESERVOIR
NFR BEAR PAW BASIN, LLC
MONTANA

DATE : 12/27/2011
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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$-----	NET GAS SALES -----M$-----
01-2012	7.0	2.308	0.000	1.055	0.000	76.859	0.000	81.057	0.000
12-2012	14.5	74.031	0.000	30.342	0.000	76.711	0.000	2327.592	0.000
12-2013	22.8	136.336	0.000	59.509	0.000	72.909	0.000	4338.773	0.000
12-2014	29.3	175.345	0.000	81.571	0.000	69.672	0.000	5683.200	0.000
12-2015	31.0	177.875	0.000	83.658	0.000	68.334	0.000	5716.713	0.000
12-2016	31.0	168.514	0.000	79.251	0.000	68.075	0.000	5395.047	0.000
12-2017	31.0	159.696	0.000	75.100	0.000	68.357	0.000	5133.563	0.000
12-2018	31.0	151.381	0.000	71.186	0.000	68.358	0.000	4866.083	0.000
12-2019	30.1	142.667	0.000	66.963	0.000	68.358	0.000	4577.413	0.000
12-2020	30.0	135.221	0.000	63.454	0.000	68.358	0.000	4337.604	0.000
12-2021	30.0	128.261	0.000	60.185	0.000	68.359	0.000	4114.168	0.000
12-2022	29.8	121.577	0.000	57.046	0.000	68.360	0.000	3899.656	0.000
12-2023	29.0	114.910	0.000	53.914	0.000	68.363	0.000	3685.722	0.000
12-2024	29.0	109.112	0.000	51.192	0.000	68.363	0.000	3499.639	0.000
12-2025	28.4	103.085	0.000	48.276	0.000	68.365	0.000	3300.408	0.000
S TOT	2.8	1900.317	0.000	882.701	0.000	69.057	0.000	60956.641	0.000
AFTER	2.8	1299.803	0.000	608.327	0.000	68.368	0.000	41589.816	0.000
TOTAL	2.8	3200.120	0.000	1491.029	0.000	68.776	0.000	102546.453	0.000

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	81.057	7.506	0.000	15.716	15.716	0.000	57.834	57.834	57.605
12-2012	2327.592	90.288	0.000	282.532	282.532	3762.257	-1807.486	-1749.651	-1742.450
12-2013	4338.773	215.722	0.000	464.665	464.665	3895.764	-237.378	-1987.029	-1971.501
12-2014	5683.200	376.247	0.000	587.904	587.904	1225.000	3494.048	1507.019	776.135
12-2015	5716.713	491.800	0.000	618.730	618.730	0.000	4606.183	6113.202	4079.269
12-2016	5395.047	498.300	0.000	634.198	634.198	0.000	4262.550	10375.752	6857.613
12-2017	5133.563	471.636	0.000	641.400	641.400	0.000	4020.527	14396.279	9239.929
12-2018	4866.083	447.054	0.000	641.400	641.400	0.000	3777.628	18173.908	11274.832
12-2019	4577.413	423.581	0.000	604.590	604.590	0.000	3549.241	21723.150	13012.899
12-2020	4337.604	398.989	0.000	601.244	601.244	0.000	3337.372	25060.521	14498.645
12-2021	4114.168	378.116	0.000	601.244	601.244	0.000	3134.809	28195.330	15767.336
12-2022	3899.656	355.704	0.000	597.963	597.963	0.000	2945.989	31141.320	16851.232
12-2023	3685.722	337.072	0.000	581.562	581.562	0.000	2767.088	33908.406	17776.744
12-2024	3499.639	317.537	0.000	581.562	581.562	0.000	2600.541	36508.949	18567.488
12-2025	3300.408	301.476	0.000	558.803	558.803	0.000	2440.130	38949.078	19242.004
S TOT	60956.641	5111.027	0.000	8013.513	8013.513	8883.022	38949.078	38949.078	19242.004
AFTER	41589.816	3832.233	0.000	10857.546	10857.546	0.000	26900.045	65849.117	22962.303
TOTAL	102546.453	8943.261	0.000	18871.061	18871.061	8883.022	65849.125	65849.117	22962.303

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	33.0	0.0	LIFE, YRS.	37.67	5.00	36356.602
GROSS ULT., MB & MMF	3910.181	0.000	DISCOUNT %	10.00	8.00	27260.033
GROSS CUM., MB & MMF	710.061	0.000	UNDISCOUNTED PAYOUT, YRS.	0.00	10.00	22962.305
GROSS RES., MB & MMF	3200.120	0.000	DISCOUNTED PAYOUT, YRS.	0.00	12.00	19594.555
NET RES., MB & MMF	1491.029	0.000	UNDISCOUNTED NET/INVEST.	8.41	15.00	15750.172
NET REVENUE, M$	102546.461	0.000	DISCOUNTED NET/INVEST.	3.88	18.00	12894.532
INITIAL PRICE, $	60.741	8.000	RATE-OF-RETURN, PCT.	93.51	20.00	11375.629
INITIAL N.I., PCT.	45.722	0.000	INITIAL W.I., PCT.	52.351	30.00	6481.036
FINAL N.I., PCT.	54.203	0.000	FINAL W.I., PCT.	57.263	50.00	2375.563
					100.00	-354.559

PDP - SAWTOOTH RESERVOIR
NFR BEAR PAW BASIN, LLC
MONTANA

DATE : 12/27/2011
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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----
01-2012	7.0	2.308	0.000	1.055	0.000	76.859	0.000	81.057	0.000
12-2012	7.0	24.333	0.000	11.111	0.000	76.872	0.000	854.100	0.000
12-2013	7.0	24.512	0.000	11.176	0.000	73.185	0.000	817.928	0.000
12-2014	7.0	22.621	0.000	10.299	0.000	69.999	0.000	720.884	0.000
12-2015	7.0	20.933	0.000	9.516	0.000	68.651	0.000	653.305	0.000
12-2016	7.0	19.419	0.000	8.816	0.000	68.411	0.000	603.123	0.000
12-2017	7.0	18.056	0.000	8.187	0.000	68.710	0.000	562.499	0.000
12-2018	7.0	16.823	0.000	7.618	0.000	68.728	0.000	523.571	0.000
12-2019	6.1	14.836	0.000	6.574	0.000	68.763	0.000	452.027	0.000
12-2020	6.0	13.782	0.000	6.084	0.000	68.782	0.000	418.489	0.000
12-2021	6.0	12.894	0.000	5.683	0.000	68.798	0.000	391.008	0.000
12-2022	5.8	11.979	0.000	5.270	0.000	68.821	0.000	362.654	0.000
12-2023	5.0	10.791	0.000	4.727	0.000	68.876	0.000	325.570	0.000
12-2024	5.0	10.200	0.000	4.464	0.000	68.883	0.000	307.495	0.000
12-2025	4.4	9.118	0.000	3.885	0.000	68.958	0.000	267.871	0.000
S TOT	1.0	232.604	0.000	104.464	0.000	70.279	0.000	7341.579	0.000
AFTER	1.0	87.845	0.000	34.178	0.000	69.259	0.000	2367.127	0.000
TOTAL	1.0	320.449	0.000	138.641	0.000	70.027	0.000	9708.706	0.000

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	81.057	7.506	0.000	15.716	15.716	0.000	57.834	57.834	57.605
12-2012	854.100	79.090	0.000	172.881	172.881	0.000	602.129	659.964	630.037
12-2013	817.928	75.740	0.000	191.142	191.142	0.000	551.046	1211.010	1108.307
12-2014	720.884	66.754	0.000	195.921	195.921	0.000	458.209	1669.219	1469.860
12-2015	653.305	60.496	0.000	200.819	200.819	0.000	391.991	2061.210	1751.056
12-2016	603.123	54.567	0.000	205.839	205.839	0.000	342.717	2403.926	1974.537
12-2017	562.499	48.356	0.000	208.176	208.176	0.000	305.966	2709.893	2155.919
12-2018	523.571	44.938	0.000	208.176	208.176	0.000	270.457	2980.350	2301.678
12-2019	452.027	41.570	0.000	171.366	171.366	0.000	239.090	3219.440	2418.815
12-2020	418.489	36.079	0.000	168.020	168.020	0.000	214.390	3433.830	2514.304
12-2021	391.008	33.351	0.000	168.020	168.020	0.000	189.637	3623.467	2591.082
12-2022	362.654	28.177	0.000	164.740	164.740	0.000	169.737	3793.204	2653.564
12-2023	325.570	25.922	0.000	148.339	148.339	0.000	151.310	3944.513	2704.187
12-2024	307.495	21.944	0.000	148.339	148.339	0.000	137.212	4081.725	2745.927
12-2025	267.871	20.663	0.000	125.579	125.579	0.000	121.629	4203.353	2779.562
S TOT	7341.579	645.153	0.000	2493.074	2493.074	0.000	4203.353	4203.353	2779.562
AFTER	2367.127	200.466	0.000	1293.917	1293.917	0.000	872.743	5076.097	2918.586
TOTAL	9708.706	845.619	0.000	3786.991	3786.991	0.000	5076.097	5076.097	2918.586

	OIL	GAS				P.W. %	P.W., M$
GROSS WELLS	9.0	0.0	LIFE, YRS.	34.67		5.00	3685.582
GROSS ULT., MB & MMF	1030.510	0.000	DISCOUNT %	10.00		8.00	3179.088
GROSS CUM., MB & MMF	710.061	0.000	UNDISCOUNTED PAYOUT, YRS.	0.00		10.00	2918.586
GROSS RES., MB & MMF	320.449	0.000	DISCOUNTED PAYOUT, YRS.	0.00		12.00	2702.000
NET RES., MB & MMF	138.641	0.000	UNDISCOUNTED NET/INVEST.	0.00		15.00	2439.038
NET REVENUE, M$	9708.707	0.000	DISCOUNTED NET/INVEST.	0.00		18.00	2227.464
INITIAL PRICE, $	-22.844	0.000	RATE-OF-RETURN, PCT.	100.00		20.00	2109.213
INITIAL N.I., PCT.	45.722	0.000	INITIAL W.I., PCT.	54.473		30.00	1687.291
FINAL N.I., PCT.	35.531	0.000	FINAL W.I., PCT.	40.625		50.00	1249.026
						100.00	825.908

PUD - SAWTOOTH RESERVOIR
NYR BEAR PAW BASIN, LLC
MONTANA

DATE : 12/27/2011
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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----
01-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	7.5	49.699	0.000	19.232	0.000	76.618	0.000	1473.492	0.000
12-2013	12.0	83.842	0.000	33.028	0.000	72.909	0.000	2408.064	0.000
12-2014	12.0	79.650	0.000	31.377	0.000	69.699	0.000	2186.942	0.000
12-2015	12.0	75.668	0.000	29.808	0.000	68.329	0.000	2036.758	0.000
12-2016	12.0	71.884	0.000	28.318	0.000	68.069	0.000	1927.557	0.000
12-2017	12.0	68.290	0.000	26.902	0.000	68.349	0.000	1838.712	0.000
12-2018	12.0	64.875	0.000	25.557	0.000	68.349	0.000	1746.776	0.000
12-2019	12.0	61.632	0.000	24.279	0.000	68.349	0.000	1659.438	0.000
12-2020	12.0	58.550	0.000	23.065	0.000	68.349	0.000	1576.466	0.000
12-2021	12.0	55.623	0.000	21.912	0.000	68.349	0.000	1497.642	0.000
12-2022	12.0	52.841	0.000	20.816	0.000	68.349	0.000	1422.760	0.000
12-2023	12.0	50.199	0.000	19.775	0.000	68.349	0.000	1351.622	0.000
12-2024	12.0	47.689	0.000	18.787	0.000	68.349	0.000	1284.042	0.000
12-2025	12.0	45.305	0.000	17.847	0.000	68.349	0.000	1219.839	0.000
S TOT	10.5	865.748	0.000	340.702	0.000	69.357	0.000	23630.111	0.000
AFTER	10.5	574.062	0.000	226.202	0.000	68.349	0.000	15460.721	0.000
TOTAL	10.5	1439.810	0.000	566.904	0.000	68.955	0.000	39090.832	0.000

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	1473.492	11.199	0.000	109.651	109.651	3762.257	-2409.615	-2409.615	-2372.487
12-2013	2408.064	131.524	0.000	201.785	201.785	0.000	2074.755	-334.860	-570.533
12-2014	2186.942	202.511	0.000	206.830	206.830	0.000	1777.602	1442.742	831.383
12-2015	2036.758	188.604	0.000	212.000	212.000	0.000	1636.154	3078.896	2004.448
12-2016	1927.557	178.492	0.000	217.300	217.300	0.000	1531.766	4610.661	3002.840
12-2017	1838.712	170.265	0.000	219.768	219.768	0.000	1448.679	6059.340	3861.217
12-2018	1746.776	161.751	0.000	219.768	219.768	0.000	1365.257	7424.598	4596.625
12-2019	1659.438	153.654	0.000	219.768	219.768	0.000	1286.006	8710.603	5226.373
12-2020	1576.466	145.981	0.000	219.768	219.768	0.000	1210.717	9921.320	5765.356
12-2021	1497.642	138.682	0.000	219.768	219.768	0.000	1139.193	11060.513	6226.397
12-2022	1422.760	131.748	0.000	219.768	219.768	0.000	1071.245	12131.758	6620.528
12-2023	1351.622	125.160	0.000	219.768	219.760	0.000	1006.694	13138.452	6957.240
12-2024	1284.042	118.902	0.000	219.768	219.768	0.000	945.371	14083.823	7244.697
12-2025	1219.839	112.957	0.000	219.768	219.768	0.000	887.115	14970.938	7489.920
S TOT	23630.111	1971.439	0.000	2925.478	2925.478	3762.257	14970.938	14970.938	7489.920
AFTER	15460.721	1431.612	0.000	4714.072	4714.072	0.000	9315.037	24285.973	8815.388
TOTAL	39090.832	3403.051	0.000	7639.550	7639.550	3762.257	24285.977	24285.973	8815.388

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	12.0	0.0	LIFE, YRS.	35.50	5.00	13755.890
GROSS ULT., MB & MMF	1439.810	0.000	DISCOUNT %	10.00	8.00	10416.363
GROSS CUM., MB & MMF	0.000	0.000	UNDISCOUNTED PAYOUT, YRS.	2.19	10.00	8815.391
GROSS RES., MB & MMF	1439.810	0.000	DISCOUNTED PAYOUT, YRS.	2.41	12.00	7547.305
NET RES., MB & MMF	566.904	0.000	UNDISCOUNTED NET/INVEST.	7.46	15.00	6081.180
NET REVENUE, M$	39090.828	0.000	DISCOUNTED NET/INVEST.	3.42	18.00	4975.349
INITIAL PRICE, $	77.003	0.000	RATE-OF-RETURN, PCT.	72.76	20.00	4379.561
INITIAL N.I., PCT.	38.697	0.000	INITIAL W.I., PCT.	44.545	30.00	2405.592
FINAL N.I., PCT.	40.318	0.000	FINAL W.I., PCT.	45.717	50.00	626.155
					100.00	-749.660

PRB - SANTOOTH RESERVOIR
NFR BEAR PAW BASIN, LLC
MONTANA

DATE : 12/27/2011
TIME : 10:22:42
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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----
01-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2013	3.8	27.982	0.000	15.305	0.000	72.707	0.000	1112.780	0.000
12-2014	9.0	63.346	0.000	34.512	0.000	69.506	0.000	2398.743	0.000
12-2015	9.0	60.179	0.000	32.786	0.000	68.136	0.000	2233.888	0.000
12-2016	9.0	57.170	0.000	31.147	0.000	67.876	0.000	2114.096	0.000
12-2017	9.0	54.311	0.000	29.589	0.000	68.156	0.000	2016.676	0.000
12-2018	9.0	51.596	0.000	28.110	0.000	68.156	0.000	1915.843	0.000
12-2019	9.0	49.016	0.000	26.704	0.000	68.156	0.000	1820.050	0.000
12-2020	9.0	46.565	0.000	25.369	0.000	68.156	0.000	1729.048	0.000
12-2021	9.0	44.237	0.000	24.101	0.000	68.156	0.000	1642.595	0.000
12-2022	9.0	42.025	0.000	22.896	0.000	68.156	0.000	1560.465	0.000
12-2023	9.0	39.924	0.000	21.751	0.000	68.156	0.000	1482.442	0.000
12-2024	9.0	37.928	0.000	20.663	0.000	68.156	0.000	1408.320	0.000
12-2025	9.0	36.031	0.000	19.630	0.000	68.156	0.000	1337.905	0.000
S TOT	8.0	610.311	0.000	332.563	0.000	68.477	0.000	22772.852	0.000
AFTER	8.0	469.568	0.000	255.813	0.000	68.156	0.000	17435.094	0.000
TOTAL	8.0	1079.879	0.000	588.375	0.000	68.337	0.000	40207.945	0.000

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2013	1112.780	8.457	0.000	71.738	71.738	3895.764	-2863.179	-2863.179	-2509.275
12-2014	2398.743	104.120	0.000	170.023	170.023	0.000	2124.599	-738.581	-831.876
12-2015	2233.888	206.858	0.000	174.274	174.274	0.000	1852.757	1114.176	496.458
12-2016	2114.096	195.765	0.000	178.631	178.631	0.000	1739.700	2853.876	1630.354
12-2017	2016.676	186.744	0.000	180.659	180.659	0.000	1649.273	4503.149	2607.570
12-2018	1915.843	177.407	0.000	180.659	180.659	0.000	1557.776	6060.926	3446.667
12-2019	1820.050	168.537	0.000	180.659	180.659	0.000	1470.854	7531.780	4166.919
12-2020	1729.048	160.110	0.000	180.659	180.659	0.000	1388.279	8920.060	4784.937
12-2021	1642.595	152.104	0.000	180.659	180.659	0.000	1309.832	10229.892	5315.025
12-2022	1560.465	144.499	0.000	180.659	180.659	0.000	1235.307	11465.199	5769.506
12-2023	1482.442	137.274	0.000	180.659	180.659	0.000	1164.509	12629.708	6158.994
12-2024	1408.320	130.410	0.000	180.659	180.659	0.000	1097.251	13726.959	6492.624
12-2025	1337.905	123.890	0.000	180.659	180.659	0.000	1033.355	14760.314	6778.263
S TOT	22772.852	1896.177	0.000	2220.598	2220.598	3895.764	14760.314	14760.314	6778.263
AFTER	17435.094	1614.388	0.000	4077.998	4077.998	0.000	11742.708	26503.023	8384.725
TOTAL	40207.945	3510.565	0.000	6298.596	6298.596	3895.764	26503.021	26503.023	8384.725

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	9.0	0.0	LIFE, YRS.	36.67	5.00	13959.318
GROSS ULT., MB & MMF	1079.879	0.000	DISCOUNT %	10.00	8.00	10159.965
GROSS CUM., MB & MMF	0.000	0.000	UNDISCOUNTED PAYOUT, YRS.	3.40	10.00	8384.723
GROSS RES., MB & MMF	1079.879	0.000	DISCOUNTED PAYOUT, YRS.	3.63	12.00	7005.737
NET RES., MB & MMF	588.375	0.000	UNDISCOUNTED NET/INVEST.	7.80	15.00	5448.643
NET REVENUE, M$	40207.949	0.000	DISCOUNTED NET/INVEST.	3.48	18.00	4307.683
INITIAL PRICE, $	72.761	0.000	RATE-OF-RETURN, PCT.	74.56	20.00	3707.966
INITIAL N.I., PCT.	54.695	0.000	INITIAL W.I., PCT.	61.773	30.00	1826.751
FINAL N.I., PCT.	54.302	0.000	FINAL W.I., PCT.	61.490	50.00	370.148
					100.00	-383.297

POS - SAWTOOTH RESERVOIR
NER BEAR PAW BASIN, LLC
MONTANA

DATE : 12/27/2011
TIME : 10:22:43
DBS FILE : Clearing
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THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$-----	NET GAS SALES -----M$-----
01-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2013	0.0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2014	1.3	9.728	0.000	5.384	0.000	69.959	0.000	376.632	0.000
12-2015	3.0	21.095	0.000	11.548	0.000	68.649	0.000	792.761	0.000
12-2016	3.0	20.041	0.000	10.971	0.000	68.389	0.000	750.271	0.000
12-2017	3.0	19.039	0.000	10.422	0.000	68.669	0.000	715.676	0.000
12-2018	3.0	18.087	0.000	9.901	0.000	68.669	0.000	679.892	0.000
12-2019	3.0	17.182	0.000	9.406	0.000	68.669	0.000	645.898	0.000
12-2020	3.0	16.323	0.000	8.936	0.000	68.669	0.000	613.602	0.000
12-2021	3.0	15.507	0.000	8.489	0.000	68.669	0.000	582.922	0.000
12-2022	3.0	14.732	0.000	8.064	0.000	68.669	0.000	553.776	0.000
12-2023	3.0	13.995	0.000	7.661	0.000	68.669	0.000	526.087	0.000
12-2024	3.0	13.295	0.000	7.278	0.000	68.669	0.000	499.783	0.000
12-2025	3.0	12.631	0.000	6.914	0.000	68.669	0.000	474.794	0.000
S TOT	2.8	191.654	0.000	104.974	0.000	68.704	0.000	7212.095	0.000
AFTER	2.8	168.328	0.000	92.135	0.000	68.670	0.000	6326.880	0.000
TOTAL	2.8	359.983	0.000	197.108	0.000	68.688	0.000	13538.975	0.000

--END-- MO-YEAR	TOT NET REVENUE -----M$-----	NET PROD TAXES -----M$-----	NET ADVAL TAXES -----M$-----	OPERATING EXPENSE -----M$-----	TOTAL EXPENSE -----M$-----	CAPITAL INVESTMENT -----M$-----	FUTURE NET CASHFLOW -----M$-----	CUMUL NET CASHFLOW -----M$-----	10.0% CUM DISC CF -----M$-----
01-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2013	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
12-2014	376.632	2.862	0.000	15.131	15.131	1225.000	-866.362	-866.362	-693.232
12-2015	792.761	35.842	0.000	31.637	31.637	0.000	725.282	-141.080	-172.694
12-2016	750.271	69.475	0.000	32.428	32.428	0.000	648.368	507.288	249.883
12-2017	715.676	66.272	0.000	32.796	32.796	0.000	616.608	1123.896	615.224
12-2018	679.892	62.958	0.000	32.796	32.796	0.000	584.138	1708.033	929.862
12-2019	645.898	59.810	0.000	32.796	32.796	0.000	553.291	2261.324	1200.792
12-2020	613.602	56.820	0.000	32.796	32.796	0.000	523.987	2785.311	1434.048
12-2021	582.922	53.979	0.000	32.796	32.796	0.000	496.147	3281.458	1634.832
12-2022	553.776	51.280	0.000	32.796	32.796	0.000	469.700	3751.158	1807.634
12-2023	526.087	48.716	0.000	32.796	32.796	0.000	444.575	4195.733	1956.324
12-2024	499.783	46.280	0.000	32.796	32.796	0.000	420.707	4616.439	2084.239
12-2025	474.794	43.966	0.000	32.796	32.796	0.000	398.032	5014.471	2194.259
S TOT	7212.095	598.259	0.000	374.365	374.365	1225.000	5014.471	5014.471	2194.259
AFTER	6326.880	585.768	0.000	771.560	771.560	0.000	4969.552	9984.022	2843.604
TOTAL	13538.975	1184.026	0.000	1145.925	1145.925	1225.000	9984.023	9984.022	2843.604

	OIL	GAS
GROSS WELLS	3.0	0.0
GROSS ULT., MB & MMF	359.983	0.000
GROSS CUM., MB & MMF	0.000	0.000
GROSS RES., MB & MMF	359.983	0.000
NET RES., MB & MMF	197.108	0.000
NET REVENUE, M$	13538.977	0.000
INITIAL PRICE, $	70.097	0.000
INITIAL N.I., PCT.	55.343	0.000
FINAL N.I., PCT.	54.203	0.000

LIFE, YRS.	37.67
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	4.22
DISCOUNTED PAYOUT, YRS.	4.41
UNDISCOUNTED NET/INVEST.	9.15
DISCOUNTED NET/INVEST.	3.94
RATE-OF-RETURN, PCT.	86.64
INITIAL W.I., PCT.	58.226
FINAL W.I., PCT.	57.263

P.W. %	P.W., M$
5.00	4955.808
8.00	3504.618
10.00	2843.604
12.00	2339.510
15.00	1782.312
18.00	1384.036
20.00	1178.890
30.00	561.402
50.00	130.235
100.00	-47.510

USERS = MHAT

DATE : 12/27/2011
TIME : 10:22:14
DBS FILE : Clearing
SETUP FILE : TCGAC

THE OIL & GAS ASSET CLEARINGHOUSE - ECONOMIC SUMMARY

EFFECTIVE DATE: 01/2012

--END-- MO-YEAR	NO. OF WELLS	GROSS OIL PRODUCTION ---MBBLS---	GROSS GAS PRODUCTION ----MMCF---	NET OIL PRODUCTION ---MBBLS---	NET GAS PRODUCTION ----MMCF---	NET OIL PRICE ---$/BBL---	NET GAS PRICE ---$/MCF---	NET OIL SALES -----M$----	NET GAS SALES -----M$----
01-2012	7.0	0.000	7.026	0.000	3.938	0.000	1.987	0.000	7.828
12-2012	8.0	0.000	97.823	0.000	53.203	0.000	2.004	0.000	106.632
12-2013	8.0	0.000	84.885	0.000	46.559	0.000	2.307	0.000	107.413
12-2014	8.0	0.000	73.734	0.000	40.558	0.000	2.477	0.000	100.470
12-2015	8.0	0.000	66.254	0.000	36.498	0.000	2.501	0.000	94.937
12-2016	8.0	0.000	60.681	0.000	33.459	0.000	2.720	0.000	91.017
12-2017	8.0	0.000	56.274	0.000	31.048	0.000	2.850	0.000	88.483
12-2018	8.0	0.000	52.602	0.000	29.033	0.000	2.850	0.000	82.734
12-2019	8.0	0.000	49.330	0.000	27.233	0.000	2.849	0.000	77.600
12-2020	8.0	0.000	46.327	0.000	25.578	0.000	2.849	0.000	72.881
12-2021	8.0	0.000	43.543	0.000	24.041	0.000	2.849	0.000	68.502
12-2022	8.0	0.000	40.930	0.000	22.599	0.000	2.849	0.000	64.392
12-2023	8.0	0.000	38.475	0.000	21.243	0.000	2.849	0.000	60.528
12-2024	8.0	0.000	36.166	0.000	19.968	0.000	2.849	0.000	56.897
12-2025	8.0	0.000	33.996	0.000	18.770	0.000	2.849	0.000	53.483
S TOT	1.0	0.000	788.045	0.000	433.728	0.000	2.614	0.000	1133.794
AFTER	1.0	0.000	490.110	0.000	223.875	0.000	2.807	0.000	628.443
TOTAL	1.0	0.000	1278.154	0.000	657.602	0.000	2.680	0.000	1762.237

--END-- MO-YEAR	TOT NET REVENUE -----M$----	NET PROD TAXES -----M$----	NET ADVAL TAXES -----M$----	OPERATING EXPENSE -----M$----	TOTAL EXPENSE -----M$----	CAPITAL INVESTMENT -----M$----	FUTURE NET CASHFLOW -----M$----	CUMUL NET CASHFLOW -----M$----	10.0% CUM DISC CF -----M$----
01-2012	7.828	0.725	0.000	1.257	1.257	9.375	-3.529	-3.529	-3.553
12-2012	106.632	7.555	0.000	15.518	15.518	0.000	83.558	80.029	76.053
12-2013	107.413	9.780	0.000	17.157	17.157	0.000	80.476	160.505	145.953
12-2014	100.470	9.304	0.000	17.586	17.586	0.000	73.580	234.085	204.024
12-2015	94.937	8.791	0.000	18.026	18.026	0.000	68.120	302.205	252.889
12-2016	91.017	8.428	0.000	18.477	18.477	0.000	64.112	366.317	294.692
12-2017	88.483	8.194	0.000	18.686	18.686	0.000	61.603	427.920	331.203
12-2018	82.734	7.661	0.000	18.686	18.686	0.000	56.386	484.306	361.582
12-2019	77.600	7.186	0.000	18.686	18.686	0.000	51.728	536.034	386.918
12-2020	72.881	6.749	0.000	18.686	18.686	0.000	47.446	583.480	408.045
12-2021	68.502	6.343	0.000	18.686	18.686	0.000	43.472	626.952	425.642
12-2022	64.392	5.963	0.000	18.686	18.686	0.000	39.743	666.695	440.267
12-2023	60.528	5.605	0.000	18.686	18.686	0.000	36.237	702.932	452.391
12-2024	56.897	5.269	0.000	18.686	18.686	0.000	32.942	735.873	462.410
12-2025	53.483	4.953	0.000	18.686	18.686	0.000	29.844	765.717	470.662
S TOT	1133.794	102.504	0.000	256.199	256.199	9.375	765.717	765.717	470.662
AFTER	628.443	56.371	0.000	294.792	294.792	4.969	272.311	1038.028	512.471
TOTAL	1762.237	158.875	0.000	550.991	550.991	14.344	1038.028	1038.028	512.471

	OIL	GAS			P.W. %	P.W., M$
GROSS WELLS	0.0	9.0	LIFE, YRS.	43.08	5.00	689.649
GROSS ULT., MB & MMF	0.000	1690.802	DISCOUNT %	10.00	8.00	571.189
GROSS CUM., MB & MMF	0.000	412.648	UNDISCOUNTED PAYOUT, YRS.	0.12	10.00	512.471
GROSS RES., MB & MMF	0.000	1278.154	DISCOUNTED PAYOUT, YRS.	0.12	12.00	464.915
NET RES., MB & MMF	0.000	657.602	UNDISCOUNTED NET/INVEST.	73.37	15.00	408.617
NET REVENUE, M$	0.000	1762.237	DISCOUNTED NET/INVEST.	50.94	18.00	365.088
INITIAL PRICE, $	0.000	1.152	RATE-OF-RETURN, PCT.	100.00	20.00	341.204
INITIAL N.I., PCT.	0.000	56.177	INITIAL W.I., PCT.	46.029	30.00	259.410
FINAL N.I., PCT.	0.000	28.984	FINAL W.I., PCT.	33.125	50.00	180.394
					100.00	110.322

NFR ENERGY

CONFIDENTIALITY AGREEMENT

This Confidentiality Agreement (as such may be amended, supplemented or otherwise modified from time to time, this "**Agreement**"), is entered into this 6 day of January, 2012, by and among NFR Energy LLC and NFR Bear Paw Basin LLC (together, "**NFR**"), and [ ] (the "**Company**"). Both NFR and Company may be referred to individually as a "**Party**" or collectively as the "**Parties.**" NFR has in its possession certain drilling, production, engineering, geophysical, geological, financial and other information and interpretations of a valuable and confidential nature (collectively, and as defined in Paragraph 4 below, the "**Confidential Information**") relating to NFR and certain of NFR's assets and properties (the "**Properties**") located in Blaine, Choteau, Fergus and Hill Counties, Montana as shown on Exhibit "A" attached hereto (the "**Contract Area**"). In order for the Company to determine its interest in entering into a transaction with NFR regarding the Properties in the Contract Area (the "**Transaction**"), NFR is willing to disclose the Confidential Information to the Company for the sole purpose of the Company's review and evaluation of the Properties and the Transaction, provided that the Company agrees to and accepts the terms and provisions of this Agreement.

As a condition to, and in consideration for, NFR furnishing Confidential Information to the Company, the Parties agree as follows:

1. *Nondisclosure of Confidential Information.* For a period of two (2) years from the date of this Agreement, Confidential Information (or any portion thereof) shall not be used by the Company other than in connection with the purpose described above, and shall be kept strictly confidential at all times. Confidential Information may be disclosed to any of the Company's Representatives (as defined below), but only if and to the extent that such Representative needs to know the Confidential Information for the purpose described above. It is understood that (i) such Representatives shall be informed by the Company of the confidential nature of the Confidential Information and the requirement that it not be used other than for the purpose described above; (ii) such Representatives shall be required to agree to and be bound by the terms of this Agreement as a condition of receiving the Confidential Information; and (iii) in any event, the Company shall be responsible for any breach of this Agreement by any of its Representatives. The Company shall not disclose Confidential Information to any person other than as permitted hereby, and the Company shall reasonably safeguard the Confidential Information from unauthorized use or disclosure by using at least the same degree of care that the Company uses in connection with its own confidential information of similar kind.

For purposes of this Agreement, (i) a person's "**Representatives**" shall be such person's Affiliates, officers, directors, employees, agents, attorneys, accountants, advisors, potential financing sources and consultants, as well as any employees, agents and attorneys of any of the foregoing; and (ii) the term "**person**" shall be broadly interpreted to include without limitation any corporation, trust, limited liability company, company, partnership or individual. For purposes of this Agreement, the term "**Affiliates**" is hereinafter defined as any entity that, directly or indirectly, controls or is controlled by or is under common control with the entity specified. Control means ownership of greater than fifty percent (50%) of the voting interest (stock or otherwise) of such entity.

Without limiting the generality of the foregoing, in no event shall Confidential Information be utilized in any legal, administrative, governmental or other proceeding by the Company (or any party claiming by through or under the Company) against NFR.

2. *Nondisclosure of Discussions.* Without the prior written consent of NFR, the Company will not, and will direct its Representatives not to, disclose to any person (i) the fact that Confidential Information has been made available to the Company; (ii) the fact that the Company has inspected any portion of the Confidential Information; or (iii) the fact, substance or status of any discussions or negotiations regarding the Properties or the Transaction.

3. *Notice Preceding Compelled Disclosure.* If the Company or its Representatives become compelled by applicable law to disclose all or any portion of the Confidential Information, then the Company shall (i) promptly notify NFR of such compulsion and (ii) exercise all reasonable efforts to obtain a protective order or other reliable assurance that confidential treatment will be accorded to the Confidential Information. If, in the absence of a protective order or the receipt of NFR's waiver of the obligations hereunder, the Company or its Representatives are compelled to disclose any of the Confidential Information or else stand liable for contempt or suffer other censure or penalty, the Company or its Representatives, as the case may be, may disclose only such portion of the Confidential Information to the party compelling such disclosure as is required by law.

4. *Definition of "Confidential Information."* As used herein, the term "**Confidential Information**" means, collectively, all information (and copies thereof) which concerns NFR, the Properties, the Contract Area or the Transaction, either verbal or written, that is furnished to the Company or any of its Representatives by NFR or any of NFR's Representatives which is either confidential, proprietary or otherwise not generally available to the public, as well as any reports, analyses, compilations, data, studies or other documents developed or prepared by or on behalf of the Company or any of its Representatives that include, incorporate, refer to, reflect or are based in whole or in part on any such information. Any information relating to NFR, the Properties, the Contract Area or the Transaction furnished to the Company or any of the Company's Representatives by a Representative of NFR shall be deemed for the purposes of this Agreement as having been furnished by NFR. Notwithstanding the foregoing, the following will not constitute Confidential Information for the purposes of this Agreement: (a) information which is or becomes generally available to the public other than as a result of a breach of this Agreement by the Company or any of the Company's Representatives; (b) information which was already known by the Company on a nonconfidential basis prior to being furnished to the Company by NFR or NFR's Representatives; and (c) information which becomes available to the Company or the Company's Representatives on a nonconfidential basis from a source other than NFR or any of NFR's Representatives, provided that such source was not subject to any confidentiality obligation or other prohibition against transmitting the information to the Company or any of the Company's Representatives.

5. *Return of Confidential Information.* Confidential Information shall be returned to NFR immediately upon NFR's request, and no copies shall be retained by the Company or any of its Representatives; provided, however, that, notwithstanding the foregoing, any portion of the Confidential Information that consists of reports, analyses, compilations, data, studies or other documents developed or prepared by or for the Company or its Representatives that include, incorporate, refer to, reflect or are based in whole or in part on any Confidential Information shall be destroyed immediately. An officer of the Company shall certify in writing as to such destruction.

6. *Restricted Leasing Activities.* In consideration for the disclosure and delivery of the Confidential Information to it, Company and its Representatives shall not, for a period of two years from and after the date hereof, directly or indirectly, negotiate to acquire, acquire, or cause any other party to acquire an oil and gas lease or an interest in an oil and gas lease (including but not limited to any "top lease") within NFR's leasehold or ownership position which, for the avoidance of any doubt, shall mean the demarcated land shown and highlighted on the attached plat labeled "Exhibit A" ("Area of Confidentiality and Exclusion"). In the event the Company or its Representatives acquires a property or interest ("Oil and Gas Interests") in contravention of this Paragraph 6, the Company shall give written notice within ten (10) business days offering 100% of the Oil and Gas Interests so acquired. Said notice shall specify the actual acquisition costs or action associated with the Oil and Gas Interests being offered and a description of the Oil and Gas Interests, including a copy of the pertinent agreements, leases, contracts, and documents. NFR, or its designee, shall then have the option, but not the obligation, to acquire said Oil and Gas Interests, or any portion thereof, by advising the Company in writing, within twenty (20) business days of receipt of the notice from the Company, of its election to acquire all or a portion of the Oil and Gas Interests. Within ten (10) business days of receipt of NFR's or its designee's election to acquire the Oil and Gas Interests, or portion thereof, the Company shall execute and deliver an assignment, suitable for recording, to NFR or its designee of said Oil and Gas Interests, free of any charge, mortgage, encumbrance, pledge, security interest or other lien, on the same terms and conditions (as may apply) on which the Company acquired the Oil and Gas Interests, and NFR or its designee shall simultaneously deliver a check or wire transfer funds to the Company for the acquisition costs of the Oil and Gas Interests so conveyed to NFR or its designee. Any Oil and Gas Interests (i) owned or acquired prior to the execution date of this Agreement, (ii) which are subject to a confidentiality agreement executed prior to the execution date of this Agreement between the Company and a third party (iii) acquired by the Company in a larger package of oil and gas properties (a package in which Oil and Gas Interests within the Area of Confidentiality and Exclusion constitute less than fifty percent (50%) of the net mineral acres in the total package), which package could not be acquired without including the interest within the Area of Confidentiality and Exclusion, are expressly excluded from the restrictions and obligations contained in this Paragraph 6.

7. *No Warranty of Accuracy.* **The Company acknowledges the risks inherent in the exploration for and development of oil, gas and other hydrocarbons. The Company agrees and acknowledges that NFR does not make any express or implied representation or warranty as to (i) the accuracy, quality or completeness of any information provided or (ii) the presence, quality or quantity of oil, gas or other hydrocarbons or the expected results of exploration, production or marketing activities, and neither NFR nor any of its Representatives shall have any liability to the Company or any of its Representatives resulting from the use of such information by the Company or any of its Representatives. The Company further agrees that no person shall have any liability relating to the information or for any errors therein or omissions therefrom.** For the purposes of this Paragraph 7, "information" is deemed to include all information furnished by NFR or any of NFR's Representatives, whether or not such information is Confidential Information as defined in Paragraph 4.

8. *Indemnification.* **THE COMPANY AGREES TO DEFEND, INDEMNIFY, PROTECT, COMPENSATE, RELEASE AND HOLD HARMLESS NFR, ITS PARTNERS AND EACH OF THEIR REPRESENTATIVES, AFFILIATES, SUCCESSORS AND ASSIGNS FROM AND AGAINST ANY AND ALL DAMAGES, LOSSES, INJURIES, JUDGMENTS AND CLAIMS OF ANY TYPE OR CAUSE, INCLUDING ALL COSTS OF DEFENSE AGAINST THE SAME , ARISING OUT OF OR RESULTING FROM ANY**

BREACH OF THIS AGREEMENT BY COMPANY OR ANY OF ITS REPRESENTATIVES.

9. *No Waiver.* No failure or delay in exercising any right, power or privilege hereunder shall operate as a waiver thereof, nor shall any single or partial exercise thereof preclude any other or further exercise of any right, power or privilege hereunder.

10. *No Obligation or Joint Venture.* The Parties hereto understand and agree that unless and until a "**Definitive Agreement**" has been executed and delivered, no contract or agreement between the Parties shall be deemed to exist, and neither Party will be under any legal obligation of any kind whatsoever with respect to the Transaction or any other transaction by virtue of this Agreement or any written or verbal expression thereof, except, in the case of this Agreement, for the matters specifically agreed to herein. For purposes of this Agreement, the term "Definitive Agreement" does not include an executed letter of intent or any other preliminary written agreement, offer or acceptance of an offer, unless specifically so designated in writing and executed by both Parties hereto.

Furthermore, this Agreement is not intended to and does not create a partnership, joint venture or any other business combination between the Parties. The Company agrees that NFR reserves the right, in its sole and absolute discretion, to reject any or all proposals, to decline to furnish further information and to terminate discussions and negotiations with the Company at any time. The exercise by NFR of these rights shall not affect the enforceability of any provision of this Agreement.

11. *Remedies, Headings, Jurisdiction and Governing Law.* It is agreed by the Parties that money damages would not be a sufficient remedy for any breach of this Agreement by the Company or its Representatives, and NFR shall be entitled to specific performance and injunctive relief as remedies for any such breach. Such remedies shall not be deemed to be the exclusive remedies for a breach of this Agreement by the Company or any of its Representatives but shall be in addition to all other remedies available at law or in equity to NFR. This Agreement shall inure to the benefit of NFR and its successors and assigns and shall be binding on the Company's successors and assigns. The headings of the Paragraphs of this Agreement are inserted for convenience only and shall not constitute a part hereof or affect in any way the meaning or interpretation of this Agreement. THIS AGREEMENT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF TEXAS WITHOUT GIVING EFFECT TO PRINCIPLES OF CONFLICTS OF LAW.

12. *Contact with Employees.* Neither the Company nor any of its Representatives will, without the prior written consent of NFR, for a period of two (2) years from the date of this Agreement, solicit, employ or cause to be solicited the employment of any person employed by NFR of any of its Affiliates except as may be solicited or employed through a general advertisement from employment.

13. *Modifications.* No amendments, changes or modifications to this Agreement shall be valid except if the same are in writing and signed by a duly authorized representative of each of the Parties hereto.

14. *Entire Agreement.* This Agreement comprises the full and complete agreement of the Parties hereto with respect to the disclosure of the Confidential Information and supersedes and cancels all prior communications, understandings and agreements between the Parties hereto, whether written or verbal, expressed or implied.

15. *Right to Disclose.* NFR represents and warrants to the Company that it has the right to provide the Confidential Information under the terms and conditions contained herein without violating the legal rights of, or its contractual obligations to, any third party.

[Signature Page Follows]

IN WITNESS WHEREOF, the duly authorized representatives of the Parties have caused this Agreement to be executed on the date first written above.

NFR Energy LLC

By:_____
Name:
Title:

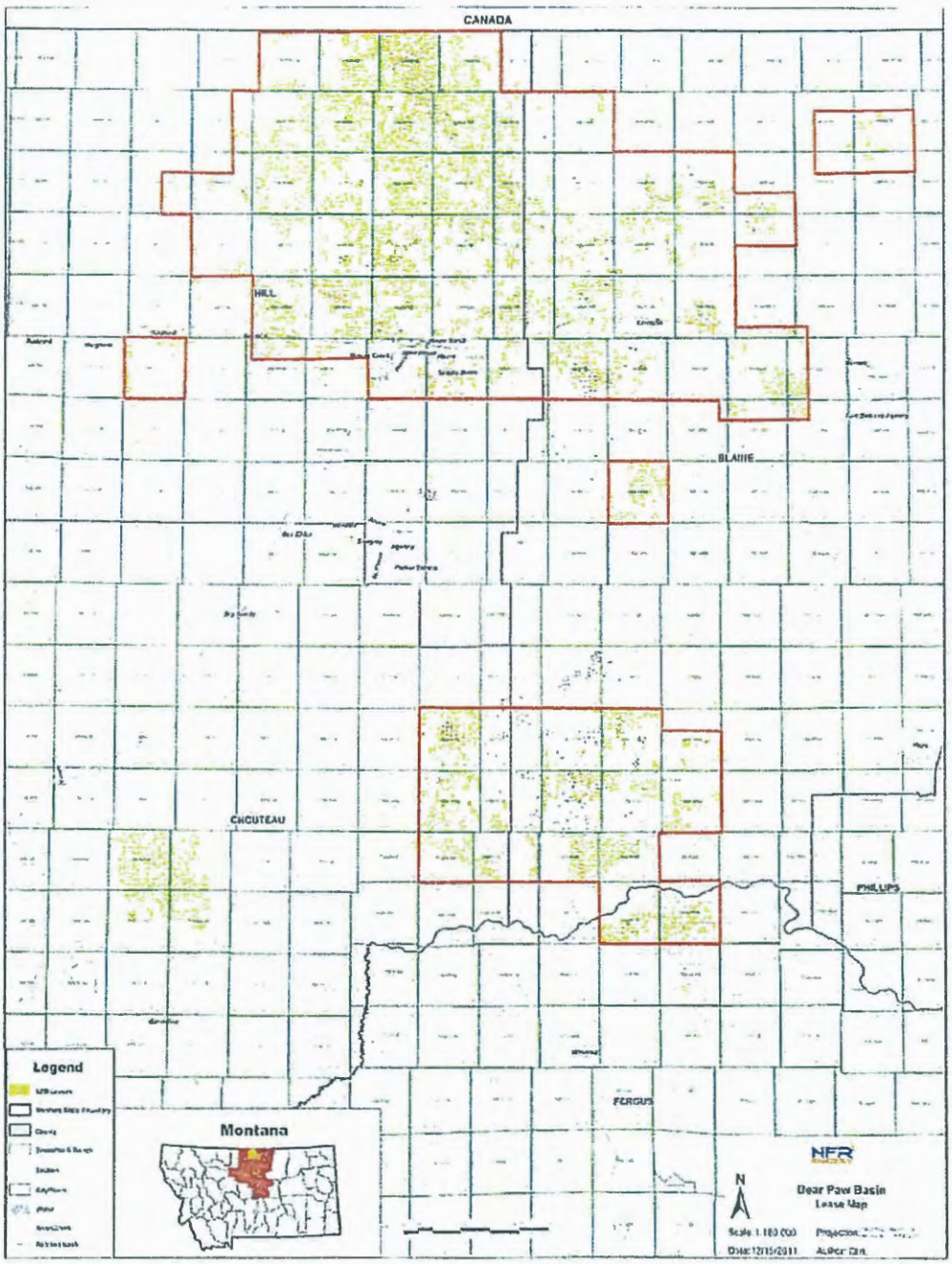
NFR Bear Paw Basin LLC
By: NFR Energy LLC, its sole member

By:_____
Name:
Title:

[Company] Northwestern Energy

By: _____
Name: Bleau J. LaFave
Title: Director - Long Term Growth

Exhibit A - Area of Confidentiality and Exclusion



ASSET REVIEW

Executive Summary

The Oil & Gas Asset Clearinghouse (The Clearinghouse) has prepared an evaluation of the interests owned by NFR ENERGY, LLC (NFR) in the Bearpaw Arch area located in Blaine, Chouteau, Fergus and Hill Counties, Montana. NFR owns over 550,000 net acres and 830,000 gross acres. Approximately 77% of the acreage (426,000 net acres) is operated and only 43% is developed. Proved net reserves are estimated to be 25.6 BCF and 705.5 MBO.

The primary productive reservoirs in the area include the Eagle, Niobrara, Medicine Hat, Judith River and the Sawtooth. Some of the 475 active wells are comingled in two or more of these reservoirs. Also being offered is NFR's 100% WI in the Redrock Drilling Company, their 75% WI in the Willow Creek and Lodge Creek Gathering Systems, and an operations field office in Havre, Montana. Combined with the reserves, these assets have a PV10 of $84.9 MM.

The Clearinghouse evaluation was prepared using Landmark's ARIES reserve evaluation software and the database is included in the Electronic Data Room (EDR). Copies of the EDR material are also available in DVD format upon request.

NFR is offering these assets in a single package. The following table is a summary of the evaluation prepared by The Clearinghouse showing the net reserves with an effective date of January 1, 2012. A NYMEX five year strip price deck for oil and gas with a settle date of December 1, 2011 was used in the evaluation.

NET RESERVE SUMMARY & PRESENT VALUE AT 10%				
CATEGORIES	Oil (MBO)	Gas (MMCF)	Total (MMCFE) (6:1)	PV10 ($M)
PRODUCTION	1,491	51,157	60,103	61,704
REDROCK DRILLING COMPANY				6,619
WILLOW CREEK AND LODGE CREEK GATHERING SYSTEMS				11,977
OPERATIONS EQUIPMENT				4,589
TOTAL ALL CATEGORIES	1,491	51,157	60,103	84,889
Effective Date: January 1, 2012		Pricing: NYMEX Settle December 1, 2011		

Asset Descriptions

Redrock Drilling Company

Redrock Drilling Company is a single rig drilling operation that is extremely well suited to drill all of the major reservoirs in the area. NFR owns 100% of Redrock Drilling Company. A typical well takes three days from spud to spud including moves making it capable of adding 90 to 100 wells per year at 100% utilization. Since 2009, Redrock has drilled approximately 56 wells for both NFR and other operators in the basin. Historically, Redrock has averaged $26.7K per well net income.

Based on the projected PUD, PRB and POS cases, Redrock is expected to drill 219 wells over the next 5 years and receive $5.84MM in net income. That income has a PV10 of $4.89MM. NFR estimates the current value of the material assets associated with Redrock to be $2.40MM. Assuming the rig could be sold at the end of the drilling program, the material assets have a PV10 of $1.73MM. Together, Redrock Drilling has a PV10 of $6.62MM.

With limited drilling service companies in the area, Redrock Drilling Company is a commodity among other basin operators. For example, Redrock Drilling Company drilled approximately 21 non-NFR wells in 2010 and produced net income of approximately $1MM. No 3rd party drilling income is assumed in the Clearinghouse representation; however it can certainly be viewed as an upside.

DRILLING OPPORTUNITIES BY RESERVE CATEGORY						
	DRILLING OPPORTUNITIES				NET INCOME	PV10
YEAR	PUD	PRB	POS	TOTAL	(MM$)	(MM$)
2012	64	0	0	64	$1.71	$1.56
2013	27	46	0	73	$1.95	$1.65
2014	0	27	46	73	$1.95	$1.50
2015	0	0	9	9	$0.24	$0.18
TOTAL	91	73	55	219	$5.84	$4.89
2016				Sale of Rig		$1.73
TOTAL	91	73	55	219	$5.84	$6.62

Willow Creek and Lodge Creek Gathering Systems

NFR is selling its 75% interest in Willow Creek and Lodge Creek Gathering Systems. The Lodge Creek Gathering System primarily connects production from St. Joe Road field to the Willow Creek system while providing gathering for other producers in the area on a limited basis. The Willow Creek Gathering System connects Lodge Creek system to Havre Pipeline, the main transmission pipeline that transports gas to the US-Canadian border. Ultimately, the gas is delivered to the Many Islands system in Saskatchewan Canada. Key features of the gathering systems include:

- Over 350 miles of steel and poly gathering lines
- 15 miles of 10" gathering line to the BC No. 4 compressor station, 15 years old
- All compressors are owned and less than 8 years old
- 99% run rate
- Current system has excess takeaway capacity
- System does provide gathering services to other producers on limited basis
- Lodge Creek owns the only gathering line that crosses the Missouri River. With this segment recently established as a national monument, it is unlikely that another system will ever be approved to transport gas from the South across the river.

Between July 2010 and June 2011, the two gathering systems transported approximately 3.0 BCF and netted almost $700K. Based on the projected PDP, PDNP, PUD, PRB and POS cases, the Willow Creek and Lodge Creek Gathering Systems is projected to transport 94.7 BCF yielding an estimated $21.5MM in net income over the next 44 years. That net income has a PV10 of $12.0MM.

GATHERING SYSTEM ECONOMICS						
	PDP	PDNP	PUD	PRB	POS	TOTAL
GROSS VOLUME (BCF)	21.1	1.1	21.1	25.0	26.4	94.7
NET INCOME ($MM)	$4.79	$0.25	$4.79	$5.68	$5.98	$21.50
PV10 ($MM)	$2.49	$0.12	$3.27	$3.17	$2.93	$11.98

Operations Equipment

The offering also includes an operations field office in Havre, Montana. The field office consists of a 10,000 square foot building constructed in 1994 with 5,600 sq ft of finished office space, including a large conference room, 4,400 sq ft of shop space and a 5.25 acre yard. The SCADA system in place allows for real time monitoring of well performance. The operations equipment, land and office building have a PV10 of $4.59MM. **The field staff is interested in remaining with the buyer.**

Production

The producing assets are located in the Bearpaw Arch located in Blaine, Chouteau, Fergus and Hill Counties in north central Montana. 75% of the PDP value (287 wells) represented are operated by NFR, while the remaining 188 wells are operated by Abraxas Petroleum Corporation, Behm Energy Incorporated, J. Burns Brown Operating, Devon Energy Production, Montana Land and Exploration and Omimex Canada LTD. Working interests range from 0.2% to 100.0% and average 47.6% while the net revenue interests range from 0.1% to 87.5% and averages 40.3%.

There are a total of 475 Proved Developed Producing wells in the package and 5 Proved Developed Non-Producing wells. The gross production for January 2012 is estimated at 393.8 MMCF (151.9 MMCF net) and 2,308 BO (1,055 BO net). Net production for December 2011 was estimated 155.4 MMCF and 1,063 BO. The "Master Well List" showing the divestment wells can be found in the Electronic Data Room (EDR).

NET RESERVE SUMMARY & PRESENT VALUE AT 10%				
RESERVE CATEGORIES	Oil (MBO)	Gas (MMCF)	Total (MMCFE) (6:1)	PV10 ($M)
PRODUCTION				
PDP	139	13,767	14,599	16,077
PDNP	0	600	600	676
PUD	567	11,188	14,589	13,276
TOTAL PROVED	**706**	**25,555**	**29,788**	**30,029**
PROB	588	12,660	16,190	17,974
POSS	197	12,942	14,125	13,701
TOTAL UNPROVED	785	25,602	30,315	31,675
TOTAL	**1,491**	**51,157**	**60,103**	**61,704**
Effective Date: January 1, 2012		Pricing: NYMEX Settle December 1, 2011		

NFR ENERGY

NFR Energy, LLC
2012 BEARPAW ARCH ASSET ACQUISITION OPPORTUNITY
NORTH-CENTRAL MONTANA

The most prolific reservoir is the Eagle. With 247 economic PDP wells and 88 projected completions it represents 68% of the active economic PDP wells, 39% of the forecast completions and 48% of the total forecast value. The average Eagle completion has a PV10 value of $233K.

With only 7 economic PDP wells and 24 projected completions, the oil bearing Sawtooth reservoir represents 37% of the total forecast value. The average Sawtooth completion has a PV10 value of $835K.

ECONOMICS BY RESERVOIR										
RESERVOIR	RESERVOIR CATEGORY	WELL COUNT	NET CAPITAL INVESTMENT (M$)	GROSS RESERVES OIL (MBO)	GROSS RESERVES GAS (MMCF)	NET RESERVES OIL (MBO)	NET RESERVES GAS (MMCF)	FUTURE NET REVENUE DISC. @ 10% (M$)	PERCENT OF TOTAL (%)	FORMATION PERCENT OF TOTAL (%)
EAGLE										
	PDP	329	0	0	28,452	0	9,061	8,969	30.40%	
	PDNP	1	4	0	568	0	119	177	0.60%	
	PUD	11	842	0	5,972	0	2,209	2,082	7.06%	
	PRB	32	3,199	0	17,625	0	8,423	7,865	26.66%	
	POS	44	4,384	0	24,188	0	11,944	10,409	35.28%	
	TOTAL	417	8,429	0	76,805	0	31,756	29,501	100%	47.81%
SAWTOOTH										
	PDP	9	0	320	0	139	0	2,919	12.71%	
	PDNP	0	0	0	0	0	0	0	0.00%	
	PUD	12	3,762	1,440	0	567	0	8,815	38.39%	
	PRB	9	3,896	1,080	0	580	0	8,385	36.52%	
	POS	3	1,225	360	0	197	0	2,844	12.38%	
	TOTAL	33	8,883	3,200	0	1,491	0	22,962	100%	37.21%
NIOBRARA										
	PDP	115	0	0	5,966	0	3,582	3,015	43.61%	
	PDNP	0	0	0	0	0	0	0	0.00%	
	PUD	68	11,258	0	15,121	0	8,978	2,379	34.42%	
	PRB	30	4,571	0	6,708	0	3,693	1,335	19.31%	
	POS	4	691	0	865	0	534	184	2.66%	
	TOTAL	217	16,520	0	28,660	0	16,787	6,913	100%	11.20%
JUDITH RIVER										
	PDP	15	0	0	1,169	0	608	755	41.56%	
	PDNP	2	16	0	750	0	340	407	22.40%	
	PUD	0	0	0	0	0	0	0	0.00%	
	PRB	2	271	0	704	0	544	390	21.46%	
	POS	4	253	0	1,312	0	465	265	14.58%	
	TOTAL	23	541	0	3,935	0	1,956	1,816	100%	2.94%
MEDICINE HAT										
	PDP	7	0	0	921	0	516	420	81.87%	
	PDNP	2	14	0	357	0	142	93	18.13%	
	PUD	0	0	0	0	0	0	0	0.00%	
	PRB	0	0	0	0	0	0	0	0.00%	
	POS	0	0	0	0	0	0	0	0.00%	
	TOTAL	9	14	0	1,278	0	658	512	100%	0.83%
	Total	699	34,387	3,200	110,677	1,491	51,157	61,704		100.00%

The Oil & Gas Asset CLEARINGHOUSE

Leases

Leasing in the Bearpaws is driven by the quest for gas reserves from the Judith River, Niobrara and Eagle formations. Sawtooth oil is another potential zone to exploit, however, over the years gas exploration has been the dominant driver for drilling.

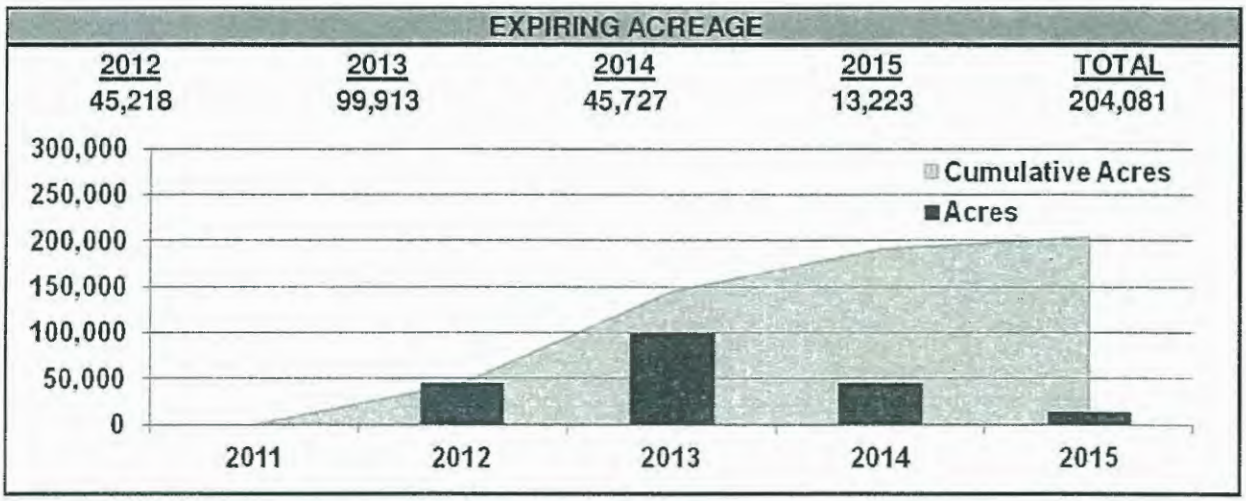
NFR's ownership of the pipelines and associated gas gathering systems in the Bearpaws has reduced competition for acreage within NFR's core area. A direct benefit of this control has kept lease prices reasonable and competition at a minimum.

Additionally, the State of Montana has promulgated rules that allows for forced pooling. The ability afforded an operator to force pool an interest rather than be forced to accept onerous farm-in terms provide the operator leverage that is often lacking in other plays. NFR has found that the ability to force pool has served to reduce competition.

Given the control NFR possesses in the core area of the Bearpaws, through the ownership of the pipelines and gathering systems, its vast land base and extensive title library, a purchaser of NFR's assets should have very little difficulty in augmenting and adding to NFR's significant acreage position.

NFR's Havre office possesses a vast title library that can be easily updated. The in-house Havre land staff can efficiently handle a moderate leasing effort involving the acquisition of between 15,000 to 20,000 acres per year. If a more aggressive leasing effort were desired, more man power would be needed.

When NFR acquired the Bearpaw asset from Klabzuba NFR continued the aggressive leasing program Klabzuba initiated prior to their sale of the asset. NFR employed a staff of land brokers consisting of two buyers and six contract landmen. These individuals were employed to acquire leases and update NFR's title library. During that effort, NFR was able to purchase acreage at an all in cost (the term "all in" is meant to include lease bonus and associated brokerage costs) approximating $50.00 per acre at a pace equaling between 50,000 to 80,000 acres per year.



Evaluation Pricing

FUTURE PRODUCT PRICES							
YEAR	2012	2013	2014	2015	2016	2017	THEREAFTER
NYMEX Oil ($/BBL)	$99.81	$96.10	$92.89	$91.52	$91.26	$91.54	Held Flat For The Economic Life
NYMEX Gas ($/MCF)	$3.84	$4.43	$4.76	$5.00	$5.23	$5.48	Held Flat For The Economic Life
Table is based on NYMEX forward curve as of December 1, 2011							

The NYMEX forward average gas price for 2013 is $4.43/MCF and increases to $5.48/MCF in 2017. The price is held flat for the remainder of the well life.

The NYMEX forward average oil price for 2013 is $96.10/BBL and decreases to $91.54/Bbl in 2017. The price is held flat for the remainder of the well life.

Economic Inputs and Assumptions

The average historical price differentials to NYMEX were calculated from LOS/LOE data on a per well basis. The Clearinghouse's Commercial Analysis, as well as the raw data provided by NFR, is included in the Electronic Data Room (EDR).

The oil price adjustment differentials varied by lease from -$22.04/BBL to -$22.44/BBL. These adjustments to the future product prices were used in the ARIES economic evaluation.

The Shrink Ratio used in ARIES is the sold gas volumes divided by the produced gas volumes for the January 2011 through July 2011 time period by lease. These ranged by lease from 98.9% to 100.0% and were applied to the future gas volumes in ARIES.

The average gas differential to NYMEX was also calculated for each well's gas sales revenue streams using sales volumes. A ratio of the gas price received to the historical NYMEX pricing provided the BTU estimate used in ARIES. These averaged 57.9% and were applied to the gas price as a future price adjustment in ARIES.

NFR Energy, LLC
2012 BEARPAW ARCH ASSET ACQUISITION OPPORTUNITY
NORTH-CENTRAL MONTANA

PARAMETER	*ASSUMPTION*
Effective Date	January 1, 2012
Discount Rate	10%
Gas & Oil Price Forecasts	Based on a NYMEX forward price deck as of December 1, 2011.
Pricing Adjustments	Oil Price adjustment differential calculated as difference in historical prices received compared to NYMEX historical oil prices and includes deducts per oil purchase agreements. Gas shrinkage is calculated as a fraction of gas sold to gas produced, accounting for fuel and gas plant volume reductions. Gas price adjustment is calculated as a fraction of historical prices received compared to NYMEX historical gas prices (Henry Hub) and is input as a Gas Price differential. This differential also includes marketing and transportations deducts per the gas purchase contract.
Operating Costs	A Commercial Analysis (CA) was prepared from LOS data provided for January 2011 through July 2011 for the operated and non-operated wells. The average monthly operating expense was calculated for each well and used in the economics as a fixed cost. Overhead was removed from the operated wells.
Capital Costs	Capital costs are based upon cost data and cost estimates provided by the NFR operations personnel and recent AFEs.
Salvage/Abandonment	Neither salvage nor abandonment costs have been projected.
Severance Tax	For any well drilled after January 1, 1999, the first 12 months of production are taxed at 0.76%. Afterward, the severance tax rate increases to 9.26%. For gas wells drilled before January 1, 1999 that are producing more than 60 MCFD, the gas severance tax rate is 15.06%. When gas production falls below 60 MCFD, the gas severance tax rate falls to 11.26%. For oil wells drilled before January 1, 1999 that are producing more than 15 BOPD, the oil severance tax rate is 12.76%. When oil production falls below 15 BOPD, the oil severance tax rate falls to 9.26%. When oil production falls below 3 BOPD, the oil severance tax rate falls to 0.76%.

The Oil & Gas Asset
CLEARINGHOUSE

Regional Geology

The Bearpaw Mountains are located in north-central Montana in Hill, Blaine and Chouteau counties. Regionally, they run east-west for 40 miles and are generally on trend with the towns of Havre and Chinook. This uplift is an excellent example of gravity-induced decollement faulting within an Upper Cretaceous marine sandstone and shale section. These mountains were formed by basement uplifts during the Laramide time. Concurrently, they were accompanied by an extensive outpouring of lava flows and the emplacement of a variety of intrusive bodies. The mountains were also the site for the mining of gold, silver, copper and iron during the late 1800's. These deposits were only marginally economic, and most of the mines were closed by 1910.

Seismic exploration has yielded high quality 2D and 3D data-sets. Investigation reveals a complex pattern of faulting beneath the glacial veneer present north of the Bearpaw Mountains. This pattern is similar to that found south of the Bearpaws, except for the occasional surface exposure of the Eagle Formation.

The aforementioned thrust sheets moved down-dip off the flanks of the uplift and were detached along organic-rich shale decollements in the shales of the Colorado Group (First and Second White Speckled Shales). Rocks beneath the decollement are relatively undeformed and have dips of approximately 3 degrees away from the uplift. The updip portions of the thrust sheets are dominated by a chaotic array of normal faults and grabens while the basinward down-dip portions are characterized by compressional thrust-faulted structures. In general, the zone of demarcation between compressional and extensional structures is located along the course of the Milk River between T32N and T33N. Typical drilling depths are usually less than 2,500 feet.

Formations of Interest

Eagle

The sandstones of the Cretaceous Eagle Formation are the primary targets for shallow gas production. These sandstones are high quality reservoirs deposited in near-shore marine and deltaic environments. To date, they have produced over 400 BCF of biogenic gas from numerous fault-traps, generally less than 640 acres in size. These gas-bearing fault-blocks are the result of gravity-induced movement down the basinward slope of the flanks of the Bearpaw Uplift.

Many one well Eagle gas fields have produced 1-2 BCF from high quality sandstone reservoirs. Porosity of approximately 30% and permeability in the darcy range are the norm. Individual sandstones can be in excess of 100 feet in thickness and stacked multiple sandstones are common.

Niobrara and Medicine Hat

The Niobrara and Medicine Hat sandstones are closely related in depositional histories as lower shoreface and shallow marine shelf deposits. Both are grey calcareous, silty sands generally exhibiting a coarsening upward morphology. The Niobrara is found approximately 500 feet below the Eagle Sand with the Medicine Hat just above the Niobrara. The sands are encased by the Colorado Group shales: First White Speckled Shale above and the Carlile Shale below. The Niobrara and Medicine Hat are both gas productive in the area and gas bearing zones are easily identified by neutron-sonic crossover on well logs. Productive zones are typically found in structural closures.

The Niobrara is productive at St. Joe Road and St. Joe Road South fields, along with various smaller fields. Sand thickness ranges from 30 to 60 feet with porosity averaging 18%. Permeability is generally low. Initial potentials range from 100 to 1000 MCFD after fracture stimulation. EUR's can reach 800 MMCF and produce for as long as 40 years.

The Medicine Hat produces gas at Fresno and Bald Prairie fields. Smaller Medicine Hat fields can also be found throughout the Bearpaws region. The sand can reach over 60 feet in thickness. As with the Niobrara, porosity is in the 15-18% range with low permeability. Initial potential reaches 550 MCFD after fracture stimulation and EUR's range from 100 to 400 MCF.

Judith River

The Judith River is located approximately 600 feet above the Eagle Formation, and was deposited for the most part in a near shore marine environment. The basal sandstone is an important gas productive interval in northern Montana and southern Saskatchewan. The sandstone is a basal marine bar which grades upward into interbedded alluvial sands and shales. The Judith River is a an excellent reservoir that ranges in thickness from 5 to 40 feet, has porosity up to 35% and permeability exceeding one darcy. This sandstone commonly traps gas in subtle structural closures which can be readily imaged with 3D seismic. Initial potentials range from 100 to 2,000 MCFD and EUR's are calculated up to 1.0 BCF. This productive sandstone is typically found at depths ranging between 500 and 1,000 feet in the area.

Sawtooth

In north-central Montana the Jurassic Sawtooth Formation unconformably overlies the Mississippian Madison Group. This unconformity represents approximately 150 million years of missing section. Regionally, the formation consists of three members; the Tampico, the Firemoon and the Bowes.

The Sawtooth is oil productive at a number of fields in Montana and Saskatchewan, including Rabbit Hills, Battlecreek and Bowes Fields. The primary oil reservoir is found as a stratigraphic high porosity coquina at the top of the formation. Thus the traps are commonly combination structural-stratigraphic in nature. The productive unit has thickness up to approximately 30 feet. Porosity can be as high as 27% with permeability ranging from 1 to 500 md. Initial Potentials are usually 10 to 250 BOPD with EUR's of 25 to 1,000 MBOE.

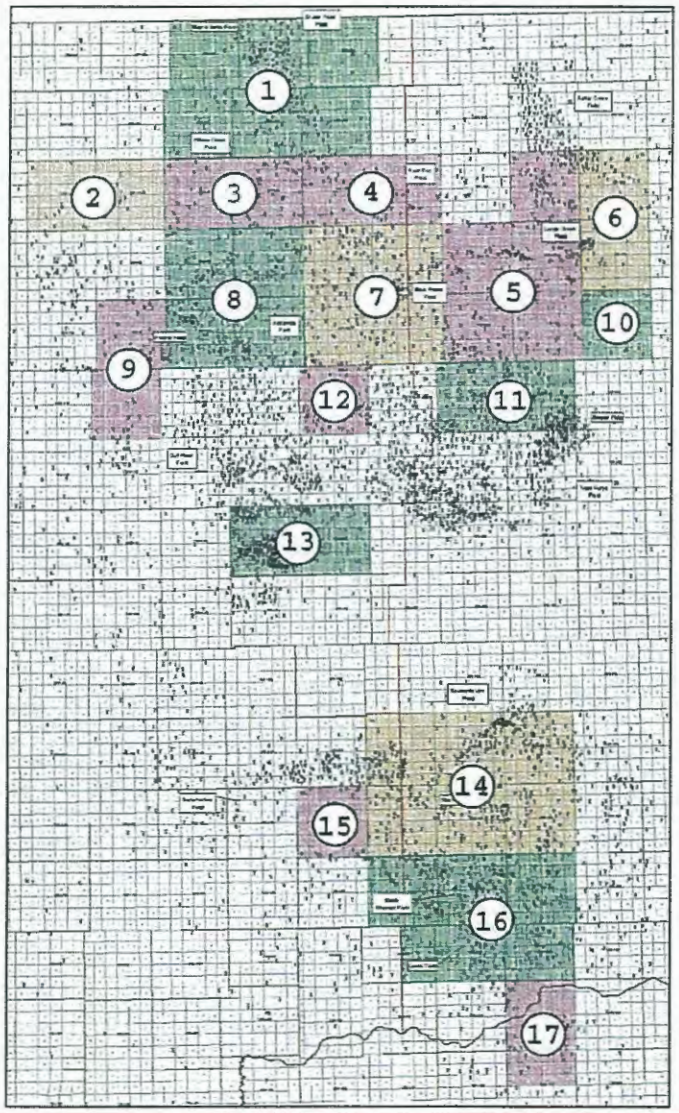
Reserve Presentation & Methodology

Reserve forecasting and economic determinations were conducted on an individual well basis. Reserves were determined by decline curve analysis for the producing (PDP) wells and by analogy for the Proved Developed Non-Producing (PDNP), Proved Undeveloped (PUD), Probable (PROB) and Possible (POS) cases.

The historical monthly production in The Clearinghouse ARIES database was obtained from a commercial data source (LASSER) with production data available through July 2011. All support production data, both public and NFR provided, are available in the EDR.

Given the vast area included in the Bearpaw divestiture, the asset was broken into 17 geographic areas.

Area 1	Area 2	Area 3
37N 14E	35N 12E	35N 14E
37N 15E	35N 13E	35N 15E
37N 16E		
36N 14E		
36N 15E		
36N 16E		
Area 4	**Area 5**	**Area 6**
35N 16E	35N 19E	35N 20E
35N 17E	34N 18E	34N 20E
Area 7	**Area 8**	**Area 9**
34N 16E	34N 14E	33N 13E
34N 17E	34N 15E	32N 13E
33N 16E	33N 14E	
33N 17E	33N 15E	
Area 10	**Area 11**	**Area 12**
33N 20E	32N 18E	32N 16E
	32N 19E	
Area 13	**Area 14**	**Area 15**
30N 15E	26N 17E	26N 16E
30N 16E	26N 18E	
	26N 19E	
	27N 17E	
	27N 18E	
	27N 19E	
Area 16	**Area 17**	
24N 17E	22N 19E	
24N 18E	23N 19E	
24N 19E		
25N 17E		
25N 18E		
25N 19E		

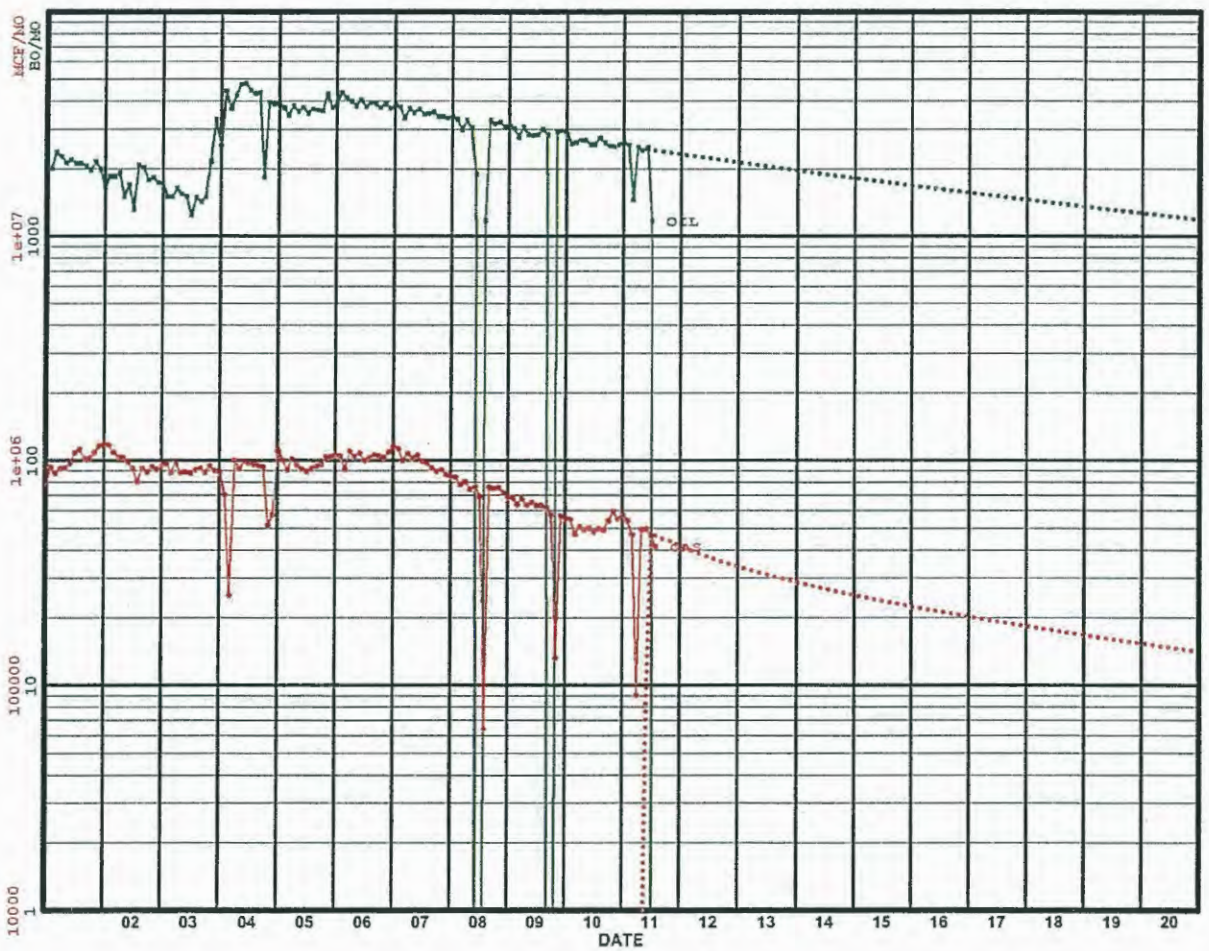


Proved Developed Producing Reserves (PDP)

The PDP reserves for each producing well were determined by decline curve analysis. There are a total of 475 active wells. However, 112 of those wells are uneconomic under the forecast parameters. The remaining 363 producing proved developed producing wells are forecast with gross reserves of 36.5 BCF and 320 MBO that have a Net PV10% of $16.1MM.

The cumulative production as of January 1, 2012 is estimated to be 181.4 BCF and 710.1 MBO. Gross January 2012 production from ARIES was estimated at 393.8 MMCF (12,703 MCFD) and 2,308 BO (75 BOPD). Net production for January was estimated at 151.9 MMCF (4,901 MCFD) and 1,055 BO (34 BOPD).

The following is a production plot for the PDP wells with The Clearinghouse's cumulative projection:



The total gas production is declining hyperbolically (n=1.1) at 20%. The total oil production is declining hyperbolically (n=0.25) at 8%.

The following table shows the PDP values of the Bearpaw Arch areas along with the reserves and EUR's for each area.

AREA	AVERAGE GWI (%)	AVERAGE NRI (%)	AVERAGE LIFE (yrs)	GROSS RESERVES OIL (MBO)	GROSS RESERVES GAS (MMCF)	GROSS EUR OIL (MBO)	GROSS EUR GAS (MMCF)	FUTURE NET REVENUE DISC. @ 10% (M$)	PERCENT OF TOTAL (%)
PROVED DEVELOPED PRODUCING									
01	73.673909	63.617175	9.7	0	6,200	0	29,035	3,631	14.59%
02	75.000000	64.148438	0.0	0	0	0	33	0	0.00%
03	70.345370	61.458399	17.0	0	352	0	6,636	168	0.68%
04	57.275619	50.167057	13.7	0	1,435	0	13,721	691	2.78%
05	51.398835	43.596954	19.9	251	1,370	672	12,874	2,726	10.95%
06	81.835938	54.315818	7.2	69	0	358	21	637	2.56%
07	57.718424	50.712624	14.7	0	1,607	0	6,837	889	3.57%
08	51.399779	44.559910	20.6	0	5,053	0	19,519	2,092	8.41%
09	56.304686	49.186797	14.9	0	340	0	1,066	131	0.53%
10	56.918340	47.804797	18.8	0	364	0	947	189	0.76%
11	28.462986	24.353013	17.3	0	4,679	0	35,977	1,364	5.48%
12	28.146992	24.001386	8.1	0	187	0	1,688	55	0.22%
13	19.486329	16.807183	12.4	0	2,146	0	20,104	436	1.75%
14	19.005568	15.178370	9.2	0	8,354	0	46,104	1,341	5.39%
15	86.404221	72.430685	10.2	0	594	0	2,800	371	1.49%
16	36.216756	28.687748	9.2	0	3,676	0	18,773	1,281	5.15%
17	71.093750	59.719231	8.1	0	150	0	1,770	75	0.30%
				320	36,508	1,031	217,906	16,077	64.60%
EQUIPMENT	100.000000	100.000000	0.4	0	0	0	0	4,589	18.44%
GATHERING	75.000000	75.000000	35.0	0	0	0	0	2,487	10.00%
REDROCK DRILLING	100.000000	100.000000	3.4	0	0	0	0	1,733	6.96%
			Total	320	36,508	1,031	217,906	24,885	100.00%

Almost 15% of the PDP value comes from the 96 wells located in Area 1. The majority of those wells (77 wells) produce from the Niobrara. Only 17 wells produce from the Eagle, and, only 2 produce from the Judith River. Understandably, more than half of the value is attributable to the Niobrara wells. However, the 19 Eagle wells represent 35% of the projected value for Area 1.

Also of note are Areas 5 and 6. Combined, those areas represent almost 14% of the PDP value despite having only 6% of the total well count. The majority of those wells (15 wells) produce from the Eagle. The remaining 7 wells produce from the Sawtooth.

Equipment, Gathering and Redrock Drilling account for 35% of the total PDP value. The PDP value attributed to Equipment includes the estimated fair market value of the land, office and other operations equipment building being offered. The PDP value attributed to Gathering includes the projected revenue expected from the operated PDP wells. The PDP value attributed to Redrock Drilling includes the estimated fair market value of the drilling equipment following the end of the projected drilling program.

Upside

NFR owns approximately 500,000 net acres and 800,000 gross acres. About ¾^{ths} of the acreage is operated and less than half of that is developed. The remaining 300,000 acres are undeveloped. More than 80% of the undeveloped acreage is operated.

The majority of the production in the area occurs from five reservoirs; the Eagle, Niobrara, Judith River, Medicine Hat and the Sawtooth. Seventeen wells are reported as being completed in two or more of these reservoirs. The projected reserves for a given reservoir were based on analogy to the average performance of the wells currently producing from that same reservoir. Consideration was given to the initial production rates and the initial decline rates of the PDP wells to model the decline curves.

Drilling and completion costs for the Eagle, Niobrara, Judith River and Medicine Hat reservoirs were estimated using the results from NFR & Klabzuba's 2008 & 2009 rig program in which 34 wells were drilled to various horizons. Because the wells are so shallow, it takes less than 2 days of drill time. As a result, the drilling expense for those 34 wells averaged $134,000. Generally, the Eagle and Judith River are the only reservoirs that don't require fracture stimulation. Therefore, their completion costs ranged from $10,000 to $15,000 per well. Completion costs for the Niobrara and Medicine Hat wells averaged $70,000 per well since, in most cases, those reservoirs usually required fracture stimulation. Lastly, the hookup for the wells averaged $24,000 per well.

The Eagle reservoir is the most prolific of the reservoirs producing in 329 of the 475 active wells. The typical Eagle well comes online at 14,800 MCF/Month and declines hyperbolically (n=0.7) at 45% initially with a terminal decline of 6%. On average, these wells produce 570 MMCF over a 35 year life. NFR estimates the capital cost associated with drilling and completing an Eagle well to be $175,000.

The Niobrara reservoir is the next most prolific of the reservoirs producing from 119 wells. The typical Niobrara well comes online at 25,800 MCF/Month and declines hyperbolically (n=0.8) at 85% initially with a terminal decline of 6%. On average, these wells produce 215 MMCF over a 19 year life. NFR estimates the capital cost associated with drilling and completing a Niobrara well to be $240,000.

The Judith River reservoir is currently producing from 27 wells. The typical Judith River well comes online at 19,130 MCFM and declines hyperbolically (n=1.8) at 75% initially with a terminal decline of 14%. On average, these wells produce 375 MMCF over a 21 year life. NFR estimates the capital cost associated with drilling and completing a Judith River well to be $155,000.

The Medicine Hat reservoir is currently producing from 7 active wells. The typical Medicine Hat well comes online at 4,070 MCFM and declines hyperbolically (n=1.8) at 60% initially with a terminal decline of 6%. On average, these wells produce 189 MMCF over a 4 year life. NFR estimates the capital cost associated with drilling and completing a Medicine Hat well to be $225,000.

The Sawtooth reservoir is the only oil reservoir in the area. Lasser reports 94 wells have been completed in the Sawtooth with first production occurring in 1986. These wells have cumulative production of 5.7 MMBO and 18.4 MMBW over the past 25 years. There are currently 52 active wells located in 5 fields; Weygand Field, Rabbit Hills Field, Battle Creek Field, Thirty Mile Field and Bowes Field.

Field Name	Cumulative Production Oil, BBL	Cumulative Production Water, BBL	Well Count Total	Well Count Active	First Production
Thirty Mile	14,246	5,214	2	2	1986
Battle Creek	139,943	7,628	2	2	2003
Weygand	297,908	43,183	4	3	1986
Rabbit Hills	2,539,481	4,630,175	17	15	1986
Bowes	2,686,562	13,723,201	69	30	1986
TOTAL	**5,678,140**	**18,409,401**	**94**	**52**	

NFR has ownership in 9 active wells located in Weygand Field (3), Rabbit Hills Field (2), Battle Creek Field (2) and Thirty Mile Field (2). The typical Sawtooth well comes online at 615 BOPM, and declines exponentially at 5%. On average, the projected EUR for these wells is 120 MBO over a 35 year life. NFR estimates the capital cost associated with drilling and completing a Sawtooth well to be $700,000.

Proved Developed Non-Producing Reserves (PDNP)

The Clearinghouse has identified 5 PDNP opportunities; 1 in the Eagle, 2 in the Judith River and 2 in the Medicine Hat. As three of the wells are currently shut-in, their projections start in February 2012. The remaining two cases start following the economic limits of the currently producing zones. NFR estimates the gross capital cost associated with these recompletions is $15K per well. The projected PDNP cases have gross reserves of 1.7 BCF with a Net PV10% of $676K and a net capital investment of $35K.

AREA	AVERAGE GWI (%)	AVERAGE NRI (%)	AVERAGE LIFE (yrs)	GROSS EUR OIL (MBO)	GROSS EUR GAS (MMCF)	FUTURE NET REVENUE DISC. @ 10% (M$)	PERCENT OF TOTAL (%)
PROVED DEVELOPED NON-PRODUCING							
01	75.000000	65.625025	21.2	0	375	303	38.21%
04	33.125000	28.984375	43.1	0	172	8	1.06%
08	62.500000	50.000000	32.2	0	185	85	10.67%
16	29.839930	22.938590	30.0	0	943	280	35.41%
				0	1,675	676	85.35%
GATHERING	75.000000	75.000000	44.0	0	0	116	14.65%
			Total	0	1,675	792	100.00%

Proved Un-Developed Reserves (PUD)

The Clearinghouse has identified 138 PUD opportunities; 11 in the Eagle, 70 in the Niobrara, 45 in the Medicine Hat and 12 in the Sawtooth reservoir. The first PUD case is projected to come online in June 2012. There are 45 Medicine Hat locations and 2 Niobrara locations that are uneconomic under the forecast conditions. The remaining 91 PUD cases are projected to have gross reserves of 21 BCF and 1,440 MBO with a Net PV10% of $13.3MM and a net capital investment of $15.9MM.

AREA	AVERAGE GWI (%)	AVERAGE NRI (%)	AVERAGE LIFE (yrs)	GROSS EUR OIL (MBO)	GROSS EUR GAS (MMCF)	FUTURE NET REVENUE DISC. @ 10% (M$)	PERCENT OF TOTAL (%)
PROVED UNDEVELOPED							
01	70.797665	60.846251	16.6	0	11,485	1,866	9.96%
03	73.404557	64.229703	14.0	0	941	454	2.43%
04	63.334167	55.417661	19.8	0	3,408	466	2.49%
05	36.717916	32.455302	34.0	840	1,368	3,872	20.67%
06	70.750000	61.660333	35.5	360	0	3,421	18.26%
09	14.285713	12.500569	14.2	0	471	43	0.23%
13	35.485711	30.121595	35.5	0	2,850	892	4.76%
16	53.392788	44.496959	35.5	240	570	2.261	12.07%
				1,440	21,093	13,276	70.87%
GATHERING	75.000000	75.000000	36.0	0	0	3,268	17.45%
REDROCK DRILLING	100.000000	100.000000	1.5	0	0	2,188	11.68%
			Total	1,440	21,093	18,733	100.00%

Areas 5, 6 and 16 have a combined PUD value of $9.6MM (51% of Total) despite having only 17% of the total well count. Twelve of those wells are projected to produce from the Sawtooth. The remaining 4 wells are projected to produce from either the Eagle or the Niobrara.

Probable Reserves (PROB)

The Clearinghouse has identified 208 PROB opportunities; 32 in the Eagle, 32 in the Niobrara, 2 in the Judith River, 133 in the Medicine Hat and 9 in the Sawtooth reservoir. The first PROB case is projected to come online in July 2013. There are 133 Medicine Hat locations and 2 Niobrara locations that are uneconomic under the forecast conditions. The remaining 73 PROB cases are projected to have gross reserves of 25 BCF and 1,080 MBO with a Net PV10% of $18MM with a net capital investment of $12MM.

AREA	AVERAGE GWI (%)	AVERAGE NRI (%)	AVERAGE LIFE (yrs)	GROSS EUR OIL (MBO)	GROSS EUR GAS (MMCF)	FUTURE NET REVENUE DISC. @ 10% (M$)	PERCENT OF TOTAL (%)
PROBABLE							
01	74.339116	64.984257	26.0	0	5,565	2,408	10.59%
02	74.999988	65.038848	10.1	0	394	62	0.27%
03	72.507419	62.662560	15.0	0	1,877	889	3.91%
04	59.679420	52.021923	25.5	0	8,306	2,601	11.44%
06	47.420000	45.052490	36.6	360	0	2,612	11.49%
07	69.648561	57.589138	36.7	0	1,140	602	2.65%
08	66.069453	56.669924	36.6	480	0	3,688	16.22%
09	74.999988	65.625137	13.3	0	329	123	0.54%
10	77.231605	67.412177	18.8	0	1,499	1,223	5.38%
11	87.500554	76.562268	36.9	0	570	486	2.14%
16	34.768852	27.281486	35.6	240	5,357	3,279	14.42%
				1,080	25,036	17,974	79.06%
GATHERING	75.000000	75.000000	37.0	0	0	3,172	13.95%
REDROCK DRILLING	100.000000	100.000000	2.5	0	0	1,589	6.99%
			Total	1,080	25,036	22,735	100.00%

Areas 6, 8 and 16 have a combined PROB value of $9.6MM (42% of Total) despite having only 26% of the total well count. Nine of the wells are projected to produce from the Sawtooth. Another 9 are projected to produce from the Eagle, and 1 is projected to produce from the Niobrara.

Possible Reserves (POS)

The Clearinghouse has identified 181 POS opportunities; 44 in the Eagle, 4 in the Niobrara, 4 in the Judith River, 126 in the Medicine Hat and 3 in the Sawtooth reservoir. The first POS case is projected to come online in July 2014. There are 126 Medicine Hat locations that are uneconomic under the forecast conditions. The remaining 55 POS cases are projected to have gross reserves of 26.4 BCF and 360 MBO with a Net PV10% of $13.7MM with a net capital investment of $6.6MM.

AREA	AVERAGE GWI (%)	AVERAGE NRI (%)	AVERAGE LIFE (yrs)	GROSS EUR OIL (MBO)	GROSS EUR GAS (MMCF)	FUTURE NET REVENUE DISC. @ 10% (M$)	PERCENT OF TOTAL (%)
POSSIBLE							
01	73.928672	63.862390	30.1	0	2,151	982	5.53%
02	62.500179	54.562659	20.3	0	1,253	449	2.53%
03	56.408013	48.668227	15.6	0	4,737	1,634	9.21%
04	57.866248	50.488341	36.6	0	7,067	2,843	16.02%
05	39.611425	34.657137	37.8	0	1,140	363	2.05%
06	62.937820	57.570738	37.6	240	1,710	2,914	16.42%
07	52.510275	44.905709	37.6	0	1,140	455	2.56%
08	52.519175	45.447339	37.7	0	3,990	1,723	9.71%
09	14.285713	12.500569	14.3	0	329	23	0.13%
14	16.449907	13.159927	37.9	0	1,140	153	0.86%
16	71.886295	63.685787	37.7	120	1,710	2,162	12.18%
				360	26,365	13,701	77.22%
GATHERING	75.000000	75.000000	38.0	0	0	2,934	16.53%
REDROCK DRILLING	100.000000	100.000000	3.0	0	0	1,109	6.25%
			Total	360	26,365	17,744	100.00%

Areas 6 and 16 have a combined POS value of $5.1MM (29% of Total) despite having only 16% of the total well count. Three of the wells are projected to produce from the Sawtooth. Another 6 are projected to produce from the Eagle.

Area 4 accounts for 16% of the total POS value. One well is projected to produce from the Niobrara and 12 wells are projected to produce from the Eagle.

Unquantified Upside

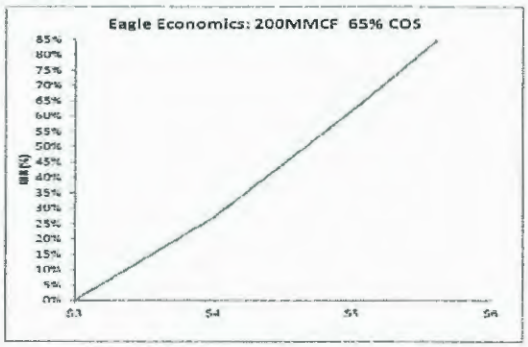
The Clearinghouse noted 12 Sawtooth locations on acreage that has expired. Assuming 100% WI and 87.5% NRI, the average Sawtooth well is estimated to have a PV10 of $1.6MM with a $700K capital investment. Leasing the acreage associated with these locations could add considerable value to this package.

There were 304 Medicine Hat locations and 4 Niobrara locations that were uneconomic under the forecast economic conditions. However, at $7.50/MCF those opportunities are economic.

Most of the Eagle, Niobrara, Judith River and Medicine Hat reservoir upside cases are based on 160 acre spacing. Volumetric analysis of the reservoirs suggests multiple opportunities for down spacing. The Clearinghouse estimates approximately 1,500 cases could be added via down spacing.

VOLUMETRIC ANALISIS BY RESERVOIR											
FORMATION	GAS/OIL	k, md	ϕ, %	Sw, %	h, ft	Pres, psig	Depth, ft	Est. Rec. / ac ft, BO/MCF	Recovery Factor, %	EUR*, MMF / MBO	Estimated Drainage, Acres
JUDITH RIVER	GAS	2000	35	45	30	350	750	202	65	375	95
EAGLE	GAS	1000	20	40	40	900	1850	314	65	570	70
MEDICINE HAT	GAS	<10	15	45	40	700	1800	168	65	189	43
NIOBRARA	GAS	100	18	45	40	700	1900	201	65	215	41
SAWTOOTH	OIL	250	25	45	20	1700	4200	875	25	120	27

*based on PDP projected reserves



Historically, NFR has had much success in identifying prospects. In the Eagle, success rates could be as high as 80%. Only half of the acreage being offered has 3-D seismic and only a limited portion of that data has been utilized to produce prospects. Already, NFR has identified prospects in the Eagle, Judith River, Niobrara, Medicine Hat, Carlile, First White Speckled Shale and Second White Speckled Shale reservoirs from existing seismic. An inventory of 191 prospects has been identified and each prospect is well documented. Further analysis of the current 3-D seismic data could uncover more prospects. Additionally, because 3-D seismic is very successful in the area the raw acreage can also be viewed as prospective. Historical seismic evaluation delivering the identification of between 0.5 - 1.5 Eagle prospects per square mile and the chance of success for the wells drilled off seismic has been 65-80% depending on the proximity to the Bearpaw uplift. While NFR only shot one 3D survey since 2009, they identified 13 additional seismic shoots that would cover over 1,000 square miles yielding an additional +500 prospects on NFR acreage alone. Because of their low F&D cost and minimal increase in base LOE, these projects can be very accretive upside. Breakeven gas price for a risked eagle exploration program is between $2/MCF and $3/MCF depending on the risk factor. Risked returns in a $4/MCF environment yield an attractive 27% - 44% IRR.

ATTACHMENT 1

Definitions of Oil & Gas Reserves

Reserves

Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability.

The intent of the SPE and WPC in approving additional classifications beyond proved reserves is to facilitate consistency among professionals using such terms. In presenting these definitions, neither organization is recommending public disclosure of reserves classified as unproved. Public disclosure of the quantities classified as unproved reserves is left to the discretion of the countries or companies involved.

Estimation of reserves is done under conditions of uncertainty. The method of estimation is called deterministic if a single best estimate of reserves is made based on known geological, engineering and economic data. The method of estimation is called probabilistic when the known geological, engineering and economic data are used to generate a range of estimates and their associated probabilities. Identifying reserves as proved, probable and possible has been the most frequent classification method and gives an indication of the probability of recovery. Because of potential differences in uncertainty, caution should be exercised when aggregating reserves of different classifications.

Reserve estimates will generally be revised as additional geologic or engineering data becomes available or as economic conditions change. Reserves do not include quantities of petroleum being held in inventory and may be reduced for usage or processing losses if required for financial reporting.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Proved Reserves

Proved Reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods and government regulations. Proved Reserves can be categorized as developed or undeveloped.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least 90% probability that the quantities actually recovered will equal or exceed the estimate.

Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve an averaging period that is consistent with the purpose of the reserve estimate, appropriate contract obligations, corporate procedures, and government regulations involved in reporting these reserves.

In general, reserves are considered proved if the commercial producibility of the reservoir is supported by actual production or formation tests. In this context, the term proved refers to the actual quantities of petroleum reserves and not just the productivity of the well or reservoir. In certain cases, proved reserves may be assigned on the basis of the well logs and/or core analysis that indicate the subject reservoir is hydrocarbon bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

The area of the reservoir considered as proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) the undrilled portions of the reservoir that can reasonable be judged as commercially productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive geological, engineering or performance data.

Reserves may be classified as proved if facilities to process and transport those reserves to market are operational at the time of the estimate or there is a reasonable expectation that such facilities will be installed. Reserves in undeveloped locations may be classified as proved undeveloped provided (1) the locations are direct offsets to wells that have indicated commercial production in the objective formation, (2) it is reasonably certain such locations are within the known proved productive limits of the objective formation, (3) the locations conform to existing well spacing regulations where applicable, and (4) it is reasonably certain the locations will be developed. Reserves from other locations are categorized as proved undeveloped only where interpretations of geological and engineering data from wells indicate with reasonable certainty that the objective formation is laterally continuous and contains commercially recoverable petroleum at locations beyond direct offsets.

Reserves which are to be produced through the application of established improved recovery methods are included in the proved classification when (1) successful testing by a pilot project or favorable response of an installed program in the same or analogous reservoir with similar rock and fluid properties provide support for the analysis on which the project was based and (2) it is reasonably certain that the project will proceed. Reserves to be recovered by improved recovery methods that have yet to be established through commercially successful applications are included in the proved classification only (1) after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program where the response provides support for the analysis on which the project is based and (2) it is reasonable certain the project will proceed.

Unproved Reserves

Unproved reserves are based on geological and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

Unproved reserves may be estimated assuming future economic conditions different from those prevailing at the time of the estimate. The effect of possible future improvements in economic conditions and technological developments can be expressed by allocating appropriate quantities of reserves to the probable and possible classifications.

Probable Reserves

Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are most likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

In general, probable reserves may include (1) reserves anticipated to be proved by normal step-out drilling where sub-surface control is inadequate to classify these reserves as proved, (2) reserves in formations that appear to be productive based on well log characteristics but lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area, (3) incremental reserves attributable to infill drilling that could have been classified as proved if closer statutory spacing had been approved at the time of the estimate, (4) reserves attributable to improved recovery methods that have been established by repeated commercially successful applications when (a) a project or pilot is planned but not in operation and (b) rock, fluid and reservoir characteristics appear favorable for commercial application, (5) reserves in an area of a formation that appear to be separated from the proved area by faulting and the geologic interpretation indicates the subject area is structurally higher than the proved area, (6) reserves attributable to a future workover, treatment, re-treatment, change of equipment, or other mechanical procedures, where such procedure has not been proved successful in

wells which exhibit similar behavior in analogous reservoirs, and (7) incremental reserves in proved reservoirs where an alternative interpretation of performance or volumetric data indicates significantly more reserves can be classified as proved.

Possible Reserves

Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.

In general, possible reserves may include (1) reserves which, based on geological interpretations, could possibly exist beyond areas classified as probable, (2) reserves in formation that appear to be petroleum bearing based on logs or core analysis but that may not be productive at commercial rates, (3) incremental reserves attributed to infill drilling that are subject to technical uncertainty, (4) reserves attributed to improved recovery methods when (a) a project or pilot is planned but not in operation and (b) rock, fluid and reservoir characteristics are such that a reasonable doubt exists that the project will be commercial, and (5) reserves in an area of a formation that appear to be separated from the proved area by faulting and geological interpretation indicates the subject area is structurally lower than the proved area.

Reserve Status Categories

Reserve status categories define the development and producing status of wells and reservoirs.

Developed

Developed reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered developed only after the necessary equipment has been installed or when the costs to do so are relatively minor. Developed reserves may be sub-categorized as producing or non-producing.

Producing

Reserves subcategorized as producing are expected to be recovered from completion intervals which are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Non-Producing

Reserves subcategorized as non-producing include shut-in and behind pipe reserves.

Shut-in reserves are expected to be recovered from (1) completion intervals open at the time of the estimate but which had not started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not cable of production for mechanical reasons. Behind pipe reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production.

Undeveloped

Undeveloped reserves are expected to be recovered (1) from new wells on undrilled acreage, (2) from deepening existing wells to a different reservoir, or (3) where a relatively large expenditure is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

STEPHAN R SMITH - PE

Date: 1/26/2012 CONSULTING PETROLEUM ENGINEER Time: 9:15 AM

ANNUAL CashFlow & PLOT - Oil/NGL/Gas

Summary Lease Report

Date	| <<<<< GROSS PRODUCTION>| Oil (Bbl)	ACRES	Gas (Mcf)	|<<<< NET PRODUCTION>| Oil (Bbl)	ACRES	Gas (Mcf)	|<AVERAGE PRICES >>| OIL ($/Bbl)	ACRES ($/Acre)	GAS ($/Mcf)
12/2012	26,639	0	4,112,369	12,164	0	1,600,716	76.91	0.00	1.61
12/2013	24,510	0	3,414,196	11,175	0	1,326,473	73.20	0.00	1.96
12/2014	22,618	0	2,915,576	10,297	0	1,132,187	69.99	0.00	2.19
12/2015	20,930	0	2,523,814	9,515	0	980,113	68.62	0.00	2.34
12/2016	19,416	0	2,222,625	8,815	0	862,419	68.36	0.00	2.48
12/2017	17,359	0	1,991,244	7,762	0	768,613	68.64	0.00	2.66
12/2018	15,822	0	1,776,930	7,008	0	680,427	68.64	0.00	2.66
12/2019	14,753	0	1,592,154	6,523	0	607,572	68.64	0.00	2.66
Remainder:	156,163	0	14,062,442	63,260	0	5,445,395	68.64	0.00	2.68
Grand Total:	318,209	0	34,611,350	136,519	0	13,403,916	69.83	0.00	2.40

Date	Well Count	WI LOE Expenses ($)	Taxes ($)	Operating Income ($)	Capital Costs ($)	Periodic Cashflow ($)	Cumulative Cash Flow ($)	Discounted Cashflow ($)	Cumulative 10% Disc CF ($)
12/2012	320	807,301	318,583	2,392,083	0	2,392,083	2,392,083	2,273,957	2,273,957
12/2013	316	807,819	323,655	2,281,876	0	2,281,876	4,673,958	1,972,344	4,246,300
12/2014	305	804,938	305,826	2,090,707	0	2,090,707	6,764,665	1,643,222	5,889,522
12/2015	289	788,645	282,639	1,873,163	0	1,873,163	8,637,829	1,338,432	7,227,954
12/2016	274	779,100	264,201	1,698,100	0	1,698,100	10,335,929	1,103,091	8,331,046
12/2017	262	740,360	249,299	1,585,659	0	1,585,659	11,921,587	936,393	9,267,438
12/2018	246	681,973	222,223	1,387,001	0	1,387,001	13,308,588	744,579	10,012,017
12/2019	231	645,848	200,795	1,219,158	0	1,219,158	14,527,746	594,962	10,606,979
Remainder:		7,979,497	1,871,797	9,062,717	0	9,062,717	23,590,464	2,431,070	13,038,049
Grand Total:		14,035,481	4,039,017	23,590,464	0	23,590,464	23,590,464	13,038,049	13,038,049

Economics Summary:

	Bbl Oil	Mcf Gas
Ultimate Gross	1,028,295	216,243,711
Historic Gross	694,799	179,371,246
Gross at Eff Date	710,086	181,632,360
Remaining Gross	318,209	34,611,350
Remaining Net	136,519	13,403,916

Economics Information:

Net Payout Date:	01/2012
Rate of Return:	>100 %
Return on Investment:	0.00
Disc Return on Invest:	0.00

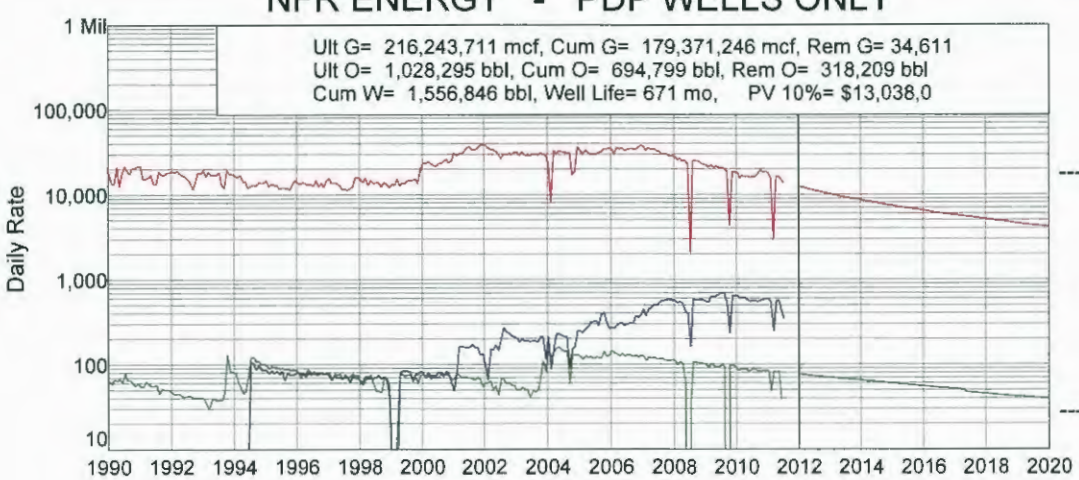
Economic Dates:

Effective Date	01/2012
Calculated Limit	11/2067
Economic Life	671 Months
	55 Years 11 Months

Discount Present Worth:

0.00 %	23,590,464
10.00 %	13,038,049
20.00 %	9,124,936
30.00 %	7,109,486
40.00 %	5,883,466
50.00 %	5,059,296
60.00 %	4,467,002
70.00 %	4,020,478
80.00 %	3,671,503
90.00 %	3,390,999
100.00 %	3,160,400

NFR ENERGY - PDP WELLS ONLY



NORTHWESTERN ENERGY
ACQUISITION OF

NFR ENERGY, MONTANA
PDP - WELLS ONLY

AECO GAS PRICE DECK

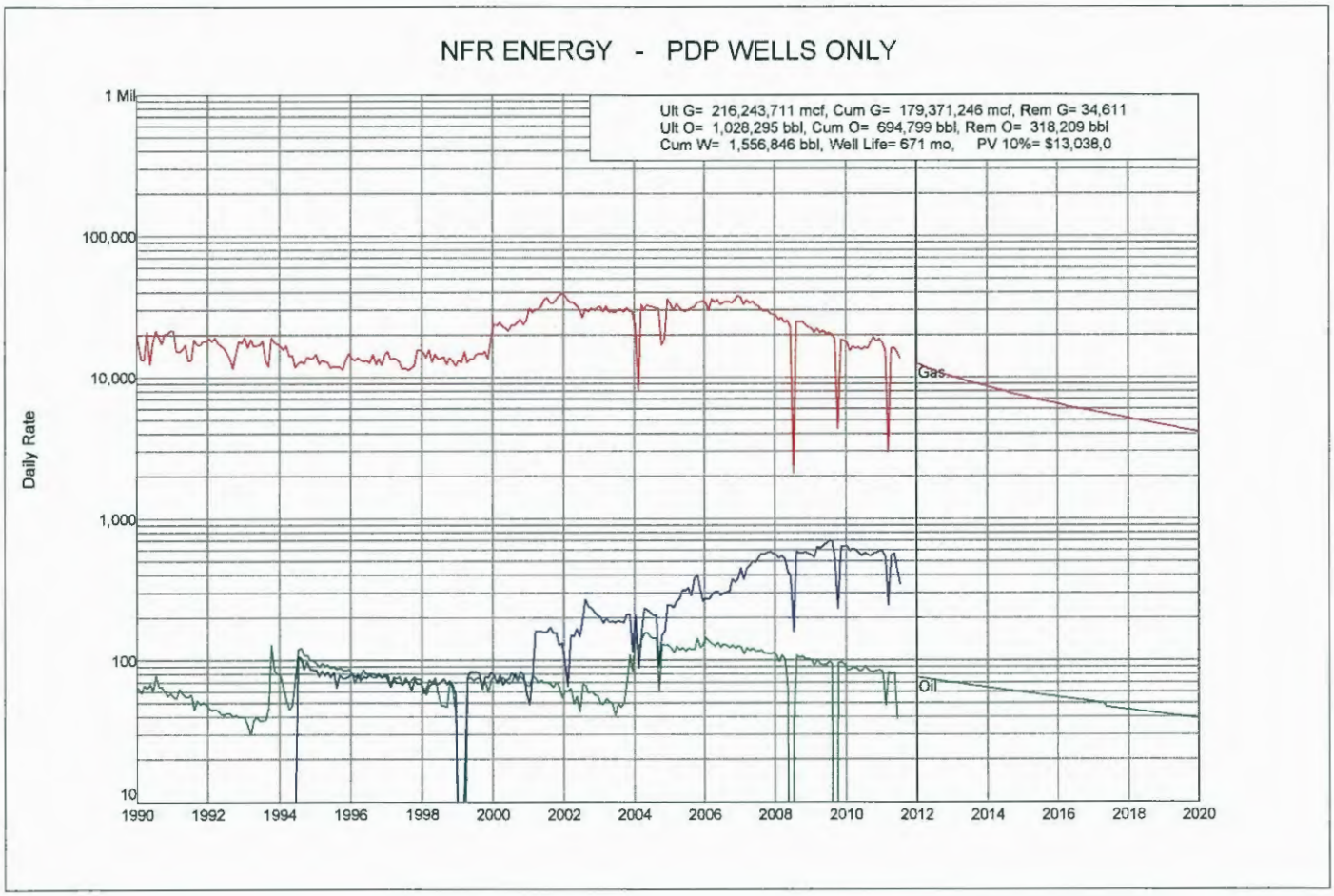
Project: c:\users\stephan r smith\documents\ihs\powertools\projects v9.1\northwest 1-24-12.mdb

Rate/Time Graph

Project: c:\users\stephan r smith\documents\ihs\powertools\projects v9.1\northwest 1-24-12.mdb

Date: 1/26/2012
Time: 9:16 AM

Summary Lease Report



STEPHAN R SMITH - PE

Date: 1/26/2012 CONSULTING PETROLEUM ENGINEER Time: 9:21 AM

ANNUAL CashFlow & PLOT - Oil/NGL/Gas

Summary Lease Report

Date	| <<<<< GROSS PRODUCTION>| Oil (Bbl)	ACRES	Gas (Mcf)	|<<<< NET PRODUCTION>| Oil (Bbl)	ACRES	Gas (Mcf)	|<AVERAGE PRICES >>| OIL ($/Bbl)	ACRES ($/Acre)	GAS ($/Mcf)
12/2012	26,639	0	4,158,101	12,164	0	1,617,154	76.91	0.00	1.79
12/2013	24,510	0	3,460,099	11,175	0	1,339,559	73.20	0.00	2.18
12/2014	22,618	0	2,968,850	10,297	0	1,146,178	69.99	0.00	2.42
12/2015	20,930	0	2,576,308	9,515	0	994,641	68.62	0.00	2.57
12/2016	19,416	0	2,272,741	8,815	0	872,726	68.36	0.00	2.72
12/2017	17,359	0	2,021,763	7,762	0	776,993	68.64	0.00	2.89
12/2018	15,822	0	1,812,988	7,008	0	694,732	68.64	0.00	2.90
12/2019	14,753	0	1,629,548	6,523	0	619,977	68.64	0.00	2.90
Remainder:	156,163	0	14,758,066	63,260	0	5,686,854	68.64	0.00	2.91
Grand Total:	318,209	0	35,658,464	136,519	0	13,748,813	69.83	0.00	2.63

Date	Well Count	WI LOE Expenses ($)	Taxes ($)	Operating Income ($)	Capital Costs ($)	Periodic Cashflow ($)	Cumulative Cash Flow ($)	Discounted Cashflow ($)	Cumulative 10% Disc CF ($)
12/2012	333	835,703	348,468	2,648,093	0	2,648,093	2,648,093	2,515,914	2,515,914
12/2013	328	834,185	356,313	2,550,562	0	2,550,562	5,198,655	2,204,866	4,720,780
12/2014	318	835,820	334,894	2,322,568	0	2,322,568	7,521,223	1,825,566	6,546,347
12/2015	307	822,119	309,534	2,081,878	0	2,081,878	9,603,101	1,487,702	8,034,048
12/2016	289	803,772	288,065	1,887,895	0	1,887,895	11,490,996	1,226,362	9,260,410
12/2017	273	761,208	269,984	1,749,776	0	1,749,776	13,240,772	1,033,292	10,293,702
12/2018	259	717,476	242,562	1,533,097	0	1,533,097	14,773,869	822,999	11,116,701
12/2019	244	676,690	218,840	1,349,844	0	1,349,844	16,123,714	658,727	11,775,428
Remainder:		8,583,354	2,076,585	10,251,135	0	10,251,135	26,374,849	2,727,184	14,502,613
Grand Total:		14,870,326	4,445,246	26,374,849	0	26,374,849	26,374,849	14,502,613	14,502,613

Economics Summary:

	Bbl Oil	Mcf Gas
Ultimate Gross	1,028,295	217,290,824
Historic Gross	694,799	179,371,246
Gross at Eff Date	710,086	181,632,360
Remaining Gross	318,209	35,658,464
Remaining Net	136,519	13,748,813

Economics Information:

Net Payout Date:	01/2012
Rate of Return:	>100 %
Return on Investment:	0.00
Disc Return on Invest:	0.00

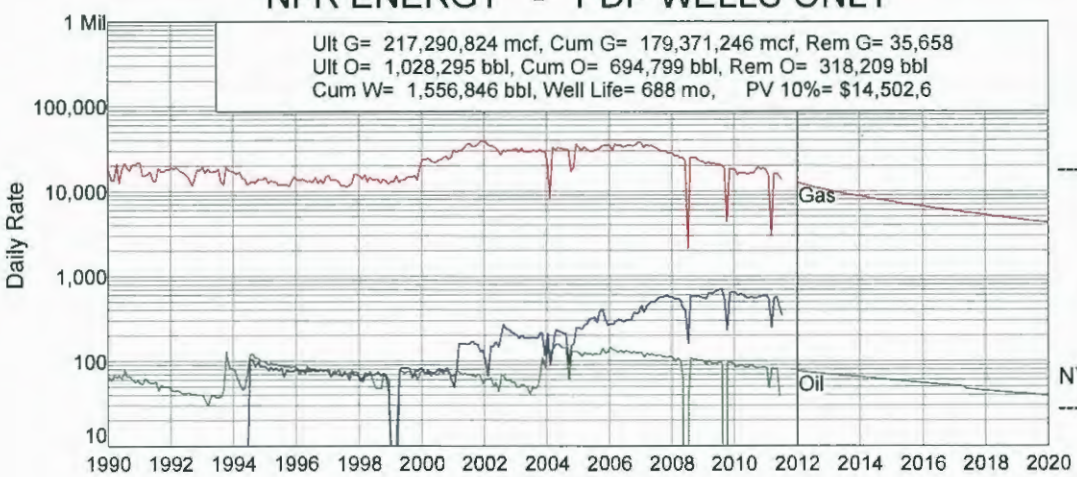
Economic Dates:

Effective Date	01/2012
Calculated Limit	04/2069
Economic Life	688 Months
	57 Years 4 Months

Discount Present Worth:

0.00 %	26,374,849
10.00 %	14,502,613
20.00 %	10,138,100
30.00 %	7,895,562
40.00 %	6,532,212
50.00 %	5,615,688
60.00 %	4,956,843
70.00 %	4,459,972
80.00 %	4,071,508
90.00 %	3,759,156
100.00 %	3,502,293

NFR ENERGY - PDP WELLS ONLY



NORTHWESTERN ENERGY
ACQUISITION OF

NFR ENERGY, MONTANA
PDP - WELLS ONLY

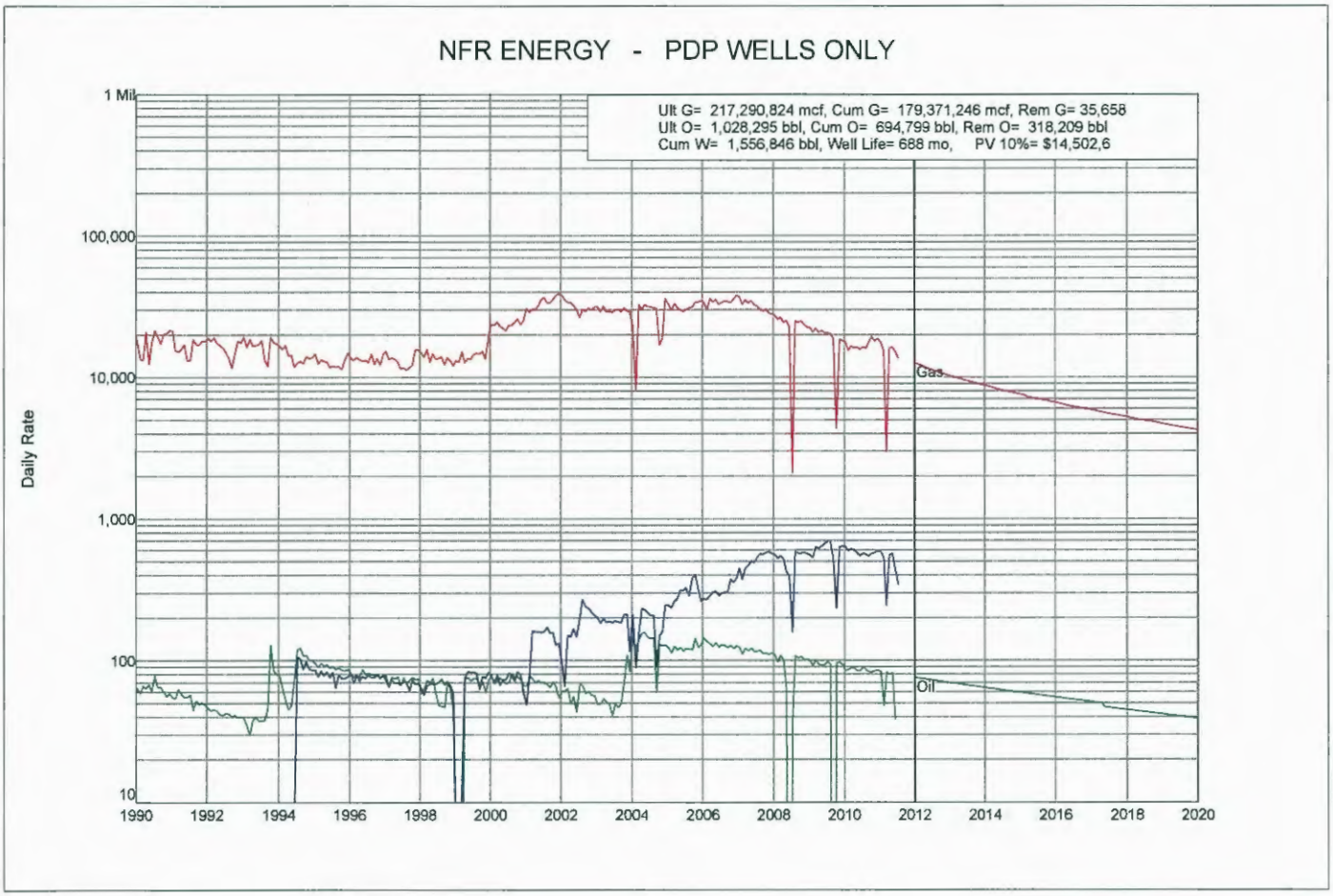
NYMEX HENRY HUB GAS PRICE DECK

Rate/Time Graph

Project: c:\users\stephan r smith\documents\ihs\powertools\projects v9.1\northwest 1-24-12.mdb

Date: 1/26/2012
Time: 9:21 AM

Summary Lease Report



NorthWestern Energy
Preliminary natural gas acquisition analysis
Confidential and for management discussion only
February 7, 2012

NFR PDP Combined + G&C

Scenario:	Total PDP (Nat Gas and Oil)
Bid (assuming price adjustment below)	$19,000
Estimated purchase price adjustment (4 months)	$0
Estimated Value of Probables	$0
Estimated strategic value of pipeline	$0
GST estimate (5% of $1M tangible non-petroleum assets)	$0
Total rate base estimate	$19,000
NPV (10%) of pre-tax cash flows ($000's)	$15,957
Earned ROE	10.25%
Cost of Debt	5.76%
Equity % of Cap Structure	48.00%
Weighted Average Cost of Capital (WACC)	7.92%

Purchase of Reserves	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2046
Average Rate Base ($000's)	18,028	16,213	14,642	13,272	12,062	10,983	10,015	9,136	8,330	7,585	6,894	6,252	5,653	5,095	56
Production (Bcf)	1.64	1.35	1.15	1.00	0.88	0.78	0.70	0.63	0.57	0.51	0.47	0.42	0.39	0.35	0.04
Estimated Revenue Requirement ($000's)	$5,030	$4,456	$4,045	$3,700	$3,393	$3,111	$2,837	$2,617	$2,430	$2,253	$2,102	$1,947	$1,809	$1,665	$312
Resulting Forward Prices ($/DKT)	$3.07	$3.31	$3.51	$3.68	$3.84	$3.97	$4.07	$4.19	$4.30	$4.39	$4.49	$4.58	$4.65	$4.72	$8.32
35 Year NPV of revenue requirement ($000's)	**$30,349**														
20 Yr Levelized Price	**$4.12**														
35 Yr Levelized Price	**$4.44**														

Procure at Forward Curve															
AECO - 5 Strip	$ 2.46	$ 3.25	$ 3.63	$ 3.89	$ 4.13	$ 4.25	$ 4.33	$ 4.43	$ 4.51	$ 4.60	$ 4.70	$ 4.79	$ 4.89	$ 4.99	$ 5.62
Revenue Requirement ($000's)	$ 4,029	$ 4,377	$ 4,186	$ 3,907	$ 3,654	$ 3,330	$ 3,019	$ 2,768	$ 2,552	$ 2,362	$ 2,200	$ 2,035	$ 1,900	$ 1,760	$ 211
35 Year NPV of revenue requirement ($000's)	**$30,358**	*Or*	*0.0%*	*greater than purchase option*											
20 Yr Levelized Price	**$4.22**														
35 Yr Levelized Price	**$4.44**														

Proved Producing

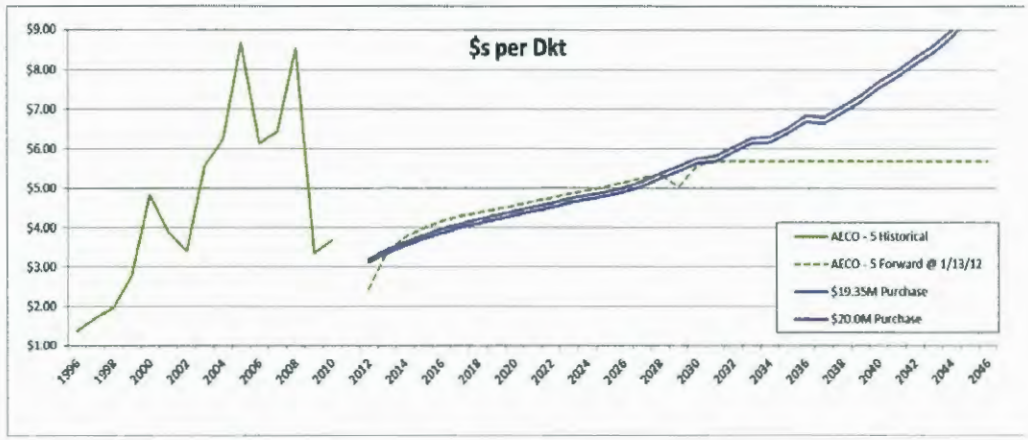
	Mdkt/yr (as provided)	Mdkt/yr	$/dkt Wellhead	$/dkt Wellhead	Gas Revenues $	G&C plus Oil Revenues	Operating Expense	Abandonment Costs	Royalties & Taxes (as provided)	Royalties & Taxes (calculated)	Net Revenues
2012	1,636	1,636	$1.65	$1.65	$2,700,129	$1,207,792.56	$684,961	$ -	$277,033	$277,033	$2,945,928
2013	1,348	1,348	$2.07	$2.07	$2,786,547	$1,009,122.56	$667,722	$ -	$285,900	$285,900	$2,842,048
2014	1,153	1,153	$2.28	$2.28	$2,631,726	$852,917.55	$661,309	$92,000	$270,015	$270,015	$2,461,319
2015	1,005	1,005	$2.43	$2.43	$2,441,030	$736,917.90	$653,096	$44,000	$250,450	$250,450	$2,230,402
2016	884	884	$2.56	$2.56	$2,264,492	$647,037.34	$636,346	$44,000	$232,337	$232,337	$1,998,846
2017	784	784	$2.71	$2.71	$2,120,512	$576,288.96	$607,844	$60,000	$217,564	$217,564	$1,811,392
2018	697	697	$2.86	$2.86	$1,994,178	$512,338.65	$556,841	$72,000	$204,603	$204,603	$1,673,073
2019	625	625	$3.03	$3.03	$1,892,893	$456,775.52	$525,148	$72,000	$194,211	$194,211	$1,558,310
2020	566	566	$3.21	$3.21	$1,814,929	$407,684.12	$500,800	$52,000	$186,212	$186,212	$1,483,602
2021	513	513	$3.38	$3.38	$1,735,111	$369,147.34	$476,284	$40,000	$178,022	$178,022	$1,409,952
2022	469	469	$3.54	$3.54	$1,658,060	$333,429.74	$459,916	$40,000	$170,117	$170,117	$1,321,457
2023	425	425	$3.69	$3.69	$1,568,797	$296,188.64	$431,588	$28,000	$160,959	$160,959	$1,244,440
2024	389	389	$3.85	$3.85	$1,495,003	$273,498.71	$414,000	$44,000	$153,387	$153,387	$1,157,114
2025	353	353	$3.85	$3.85	$1,357,629	$245,595.42	$386,860	$28,000	$139,293	$139,293	$1,049,072
2026	319	319	$3.85	$3.85	$1,227,073	$217,151.03	$365,370	$96,000	$125,898	$125,898	$856,956
2027	288	288	$3.85	$3.85	$1,109,233	$191,747.22	$353,850	$24,000	$113,807	$113,807	$809,322
2028	261	261	$3.85	$3.85	$1,002,850	$165,136.24	$323,610	$48,000	$102,892	$102,892	$693,483
2029	236	236	$3.85	$3.85	$906,790	$140,526.38	$323,610	$ -	$93,037	$93,037	$630,670
2030	213	213	$3.85	$3.85	$820,037	$117,778.10	$323,610	$ -	$84,136	$84,136	$530,069
2031	193	193	$3.85	$3.85	$741,673	$61,508.86	$260,490	$124,000	$76,096	$76,096	$342,596
2032	174	174	$3.85	$3.85	$670,877	$106,247.97	$258,330	$4,000	$68,832	$68,832	$445,962
2033	158	158	$3.85	$3.85	$606,906	$89,219.47	$258,330	$ -	$62,269	$62,269	$375,526
2034	143	143	$3.85	$3.85	$549,094	$102,586.48	$210,330	$100,000	$56,337	$56,337	$285,013
2035	129	129	$3.85	$3.85	$496,840	$87,521.99	$185,696	$40,000	$50,976	$50,976	$307,690
2036	117	117	$3.85	$3.85	$448,796	$73,981.25	$183,536	$4,000	$46,046	$46,046	$289,195
2037	104	104	$3.85	$3.85	$400,567	$90,997.70	$133,376	$104,000	$41,098	$41,098	$213,091
2038	94	94	$3.85	$3.85	$362,892	$79,811.03	$176,576	$24,000	$37,233	$37,233	$204,895
2039	85	85	$3.85	$3.85	$328,771	$68,967.35	$118,256	$ -	$33,732	$33,732	$245,751
2040	77	77	$3.85	$3.85	$297,868	$59,814.67	$79,856	$ -	$30,561	$30,561	$247,265
2041	70	70	$3.85	$3.85	$269,877	$50,855.80	$79,856	$80,000	$27,689	$27,689	$133,188
2042	64	64	$3.85	$3.85	$244,525	$43,568.67	$79,856	$4,000	$25,088	$25,088	$179,149
2043	58	58	$3.85	$3.85	$221,560	$37,084.81	$67,419	$24,000	$22,732	$22,732	$144,495
2044	52	52	$3.85	$3.85	$200,759	$30,876.34	$67,419	$ -	$20,598	$20,598	$143,619
2045	47	47	$3.85	$3.85	$181,916	$23,894.30	$67,419	$ -	$18,665	$18,665	$119,727
2046	37	37	$3.85	$3.85	$144,187	$2,260.42	$62,379	$132,000	$14,794	$14,794	($62,725)
2047					$ -	$ -				$ -	$ -
2048					$ -	$ -				$ -	$ -
2049					$ -	$ -				$ -	$ -
2050					$ -	$ -				$ -	$ -
2051					$ -	$ -				$ -	$ -
2052					$ -	$ -				$ -	$ -
2053					$ -	$ -				$ -	$ -
2054					$ -	$ -				$ -	$ -
2055					$ -	$ -				$ -	$ -
2056					$ -	$ -				$ -	$ -
2057					$ -	$ -				$ -	$ -
2058					$ -	$ -				$ -	$ -
	13,766.70	13,766.70			$39,694,129	$9,766,271	$11,641,891	$1,424,000	$4,072,618	$4,072,618	$32,321,891

NorthWestern Energy
Preliminary natural gas acquisition analysis
Confidential and for management discussion only

15-Feb-12

NFR PDP Combined - + oil G&C - Smith 10% ROE

Scenario:	Total PDP (Nat Gas and Oil)
Bid (assuming price adjustment below)	$19,350
Estimated purchase price adjustment (4 months)	$0
Estimated Value of Probables	$0
Estimated strategic value of pipeline	$0
GST estimate (5% of $1M tangible non-petroleum assets)	$0
Total rate base estimate	$19,350
NPV (10%) of pre-tax cash flows ($000's)	$15,928
Earned ROE	10.00%
Cost of Debt	5.76%
Equity % of Cap Structure	48.00%
Weighted Average Cost of Capital (WACC)	7.80%



Purchase of Reserves	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2046
Average Rate Base ($000's)	18,351	16,483	14,862	13,455	12,215	11,108	10,114	9,214	8,392	7,637	6,943	6,303	5,711	5,163	322
Production (Bcf)	1.6	1.33	1.13	0.98	0.86	0.77	0.68	0.61	0.55	0.49	0.44	0.4	0.36	0.32	0.04
Estimated Revenue Requirement ($000's)	$4,981	$4,431	$4,009	$3,633	$3,325	$3,064	$2,789	$2,557	$2,358	$2,168	$1,995	$1,841	$1,687	$1,549	$358
Resulting Forward Prices ($/DKT)	$3.11	$3.34	$3.54	$3.71	$3.86	$3.99	$4.10	$4.21	$4.31	$4.41	$4.50	$4.61	$4.70	$4.79	$10.23
47 Year NPV of revenue requirement ($000's)	$29,891														
20 Yr Levelized Price	$4.15														
35 Yr Levelized Price	$4.64														
Procure at Forward Curve															
AECO - 5 Strip	$2.44	$3.39	$3.76	$3.97	$4.17	$4.29	$4.38	$4.47	$4.56	$4.65	$4.74	$4.84	$4.94	$5.04	$5.68
Revenue Requirement ($000's)	$3,901	$4,494	$4,255	$3,887	$3,595	$3,297	$2,978	$2,717	$2,493	$2,288	$2,102	$1,931	$1,773	$1,627	$199
47 Year NPV of revenue requirement ($000's)	$29,897	Or	0.00% greater than purchase option												
20 Yr Levelized Price	$4.27														
35 Yr Levelized Price	$4.50														

Proved Producing

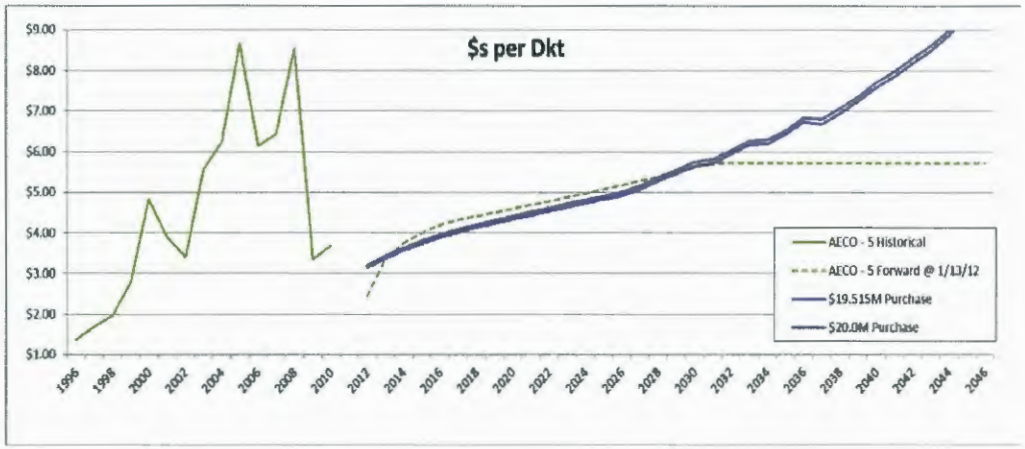
	Mdkt/yr (as provided)	Mdkt/yr	$/dkt Wellhead	$/dkt Wellhead	Gas Revenues $	G&C Oil Revenues	Operating Expense	Abandonment Costs	Royalties & Taxes (as provided)	Royalties & Taxes (calculated)	Net Revenues
2012	1,636	1,601	$1.65	$1.65	$2,641,650	$1,208,978.75	$618,703	$ -	$271,033	$271,033	$2,960,892
2013	1,348	1,326	$2.07	$2.07	$2,740,709	$1,010,133.56	$617,070	$ -	$281,197	$281,197	$2,852,576
2014	1,153	1,132	$2.28	$2.28	$2,584,130	$853,788.70	$609,420	$92,000	$265,132	$265,132	$2,471,367
2015	1,005	980	$2.43	$2.43	$2,381,400	$737,678.92	$588,239	$44,000	$244,332	$244,332	$2,242,508
2016	884	862	$2.56	$2.56	$2,208,530	$647,709.38	$573,684	$44,000	$226,595	$226,595	$2,011,960
2017	784	768	$2.71	$2.71	$2,077,670	$576,885.77	$558,955	$60,000	$213,169	$213,169	$1,822,432
2018	697	680	$2.86	$2.86	$1,946,908	$512,872.90	$513,953	$72,000	$199,753	$199,753	$1,674,075
2019	625	608	$3.03	$3.03	$1,840,720	$457,255.96	$477,827	$72,000	$188,858	$188,858	$1,559,291
2020	566	547	$3.21	$3.21	$1,755,214	$408,119.69	$447,485	$52,000	$180,085	$180,085	$1,483,763
2021	513	492	$3.38	$3.38	$1,663,108	$369,544.03	$419,070	$40,000	$170,635	$170,635	$1,402,947
2022	469	443	$3.54	$3.54	$1,567,777	$333,790.67	$392,459	$40,000	$160,854	$160,854	$1,308,255
2023	425	399	$3.69	$3.69	$1,473,587	$296,516.85	$367,538	$28,000	$151,190	$151,190	$1,223,376
2024	389	359	$3.85	$3.85	$1,380,463	$273,799.71	$344,199	$44,000	$141,635	$141,635	$1,124,428
2025	353	323	$3.85	$3.85	$1,242,032	$245,868.83	$322,342	$28,000	$127,432	$127,432	$1,010,126
2026	319	291	$3.85	$3.85	$1,118,982	$217,398.12	$301,874	$96,000	$114,808	$114,808	$823,699
2027	288	262	$3.85	$3.85	$1,007,469	$191,973.63	$282,705	$24,000	$103,366	$103,366	$789,371
2028	261	235	$3.85	$3.85	$903,646	$165,344.33	$264,753	$48,000	$92,714	$92,714	$663,523
2029	236	212	$3.85	$3.85	$815,204	$140,716.05	$247,941	$ -	$83,640	$83,640	$624,339
2030	213	191	$3.85	$3.85	$734,452	$117,951.71	$232,197	$ -	$75,355	$75,355	$544,852
2031	193	172	$3.85	$3.85	$661,392	$125,809.03	$217,452	$124,000	$67,859	$67,859	$377,890
2032	174	154	$3.85	$3.85	$592,176	$106,390.43	$203,644	$4,000	$60,757	$60,757	$430,165
2033	158	139	$3.85	$3.85	$534,497	$89,348.97	$190,713	$ -	$54,839	$54,839	$378,294
2034	143	125	$3.85	$3.85	$480,663	$102,705.39	$178,602	$100,000	$49,316	$49,316	$255,449
2035	129	113	$3.85	$3.85	$434,519	$87,628.28	$167,261	$40,000	$44,582	$44,582	$270,304
2036	117	101	$3.85	$3.85	$388,375	$74,076.28	$156,640	$4,000	$39,847	$39,847	$261,964
2037	104	91	$3.85	$3.85	$349,922	$91,084.35	$146,693	$104,000	$35,902	$35,902	$154,411
2038	94	82	$3.85	$3.85	$315,315	$79,889.14	$137,378	$24,000	$32,351	$32,351	$201,474
2039	85	74	$3.85	$3.85	$284,552	$69,035.36	$128,655	$ -	$29,195	$29,195	$195,738
2040	77	66	$3.85	$3.85	$253,790	$59,876.28	$120,485	$ -	$26,039	$26,039	$167,142
2041	70	60	$3.85	$3.85	$230,718	$50,909.23	$112,834	$80,000	$23,672	$23,672	$65,121
2042	64	54	$3.85	$3.85	$207,646	$43,617.12	$105,670	$4,000	$21,305	$21,305	$120,289
2043	58	48	$3.85	$3.85	$184,574	$37,129.05	$98,959	$24,000	$18,937	$19,332	$79,412
2044	52	44	$3.85	$3.85	$169,193	$30,915.96	$92,676	$ -	$17,359	$17,359	$90,074
2045	47	39	$3.85	$3.85	$149,967	$23,926.24	$86,791	$ -	$15,387	$15,387	$71,716
2046	37	35	$3.85	$3.85	$134,586	$2,278.76	$81,279	$132,000	$13,808	$13,808	($90,224)
2047		32	$3.85	$3.85	$123,050	$ -	$76,118		$12,625	$12,625	$34,306
2048		29	$3.85	$3.85	$111,514	$ -	$71,285		$11,441	$11,441	$28,788
2049		26	$3.85	$3.85	$99,978	$ -	$66,758		$10,258	$10,258	$22,962
2050		23	$3.85	$3.85	$88,442	$ -	$62,519		$9,074	$9,074	$16,849
2051		21	$3.85	$3.85	$80,751	$ -	$58,549		$8,285	$8,285	$13,917
2052		19	$3.85	$3.85	$73,061	$ -	$54,831		$7,496	$7,496	$10,734
2053		17	$3.85	$3.85	$65,370	$ -	$51,349		$6,707	$6,707	$7,314
2054		15	$3.85	$3.85	$57,680	$ -	$48,089		$5,918	$5,918	$3,673
2055		14	$3.85	$3.85	$53,834	$ -	$45,035		$5,523	$5,523	$3,276
2056		12	$3.85	$3.85	$46,144	$ -	$42,175		$4,734	$4,734	($766)
2057		11	$3.85	$3.85	$42,298	$ -	$39,497		$4,340	$4,340	($1,539)
2058		10	$3.85	$3.85	$38,453	$ -	$36,989		$3,945	$3,945	($2,481)
	13,766.70	13,337.00			$38,336,107	$9,840,947	$11,059,342	$1,424,000	$3,933,285	$3,933,679	$31,760,034

NorthWestern Energy
Preliminary natural gas acquisition analysis
Confidential and for management discussion only

23-Feb-12

NFR PDP Combined - + oil G&C - Smith 10% ROE

Scenario:	Total PDP (Nat Gas and Oil)
Bid (assuming price adjustment below)	$19,515
Estimated purchase price adjustment (4 months)	$0
Estimated Value of Probables	$0
Estimated strategic value of pipeline	$0
GST estimate (5% of $1M tangible non-petroleum assets)	$0
Total rate base estimate	$19,515
NPV (10%) of pre-tax cash flows ($000's)	$15,928
Earned ROE	10.00%
Cost of Debt	5.76%
Equity % of Cap Structure	48.00%
Weighted Average Cost of Capital (WACC)	7.80%



Purchase of Reserves	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2046
Average Rate Base ($000's)	18,508	16,623	14,989	13,569	12,319	11,203	10,200	9,293	8,464	7,703	7,002	6,356	5,760	5,207	325
Production (Bcf)	1.6	1.33	1.13	0.98	0.86	0.77	0.68	0.61	0.55	0.49	0.44	0.4	0.36	0.32	0.04
Estimated Revenue Requirement ($000's)	$5,015	$4,461	$4,034	$3,656	$3,346	$3,083	$2,806	$2,573	$2,372	$2,181	$2,006	$1,852	$1,697	$1,557	$360
Resulting Forward Prices ($/DKT)	$3.13	$3.36	$3.56	$3.73	$3.88	$4.01	$4.13	$4.23	$4.34	$4.43	$4.53	$4.64	$4.73	$4.82	$10.28
47 Year NPV of revenue requirement ($000's)	$30,078														
20 Yr Levelized Price	$4.18														
35 Yr Levelized Price	$4.66														
Procure at Forward Curve															
AECO - 5 Strip	$2.43	$3.37	$3.75	$3.98	$4.20	$4.33	$4.41	$4.50	$4.59	$4.69	$4.78	$4.88	$4.98	$5.08	$5.72
Revenue Requirement ($000's)	$3,892	$4,468	$4,242	$3,903	$3,616	$3,322	$3,001	$2,737	$2,513	$2,306	$2,118	$1,946	$1,786	$1,640	$200
47 Year NPV of revenue requirement ($000's)	$30,078	Or	0.00%	less than purchase option											
20 Yr Levelized Price	$4.30														
35 Yr Levelized Price	$4.53														

Proved Producing

	Mdkt/yr (as provided)	Mdkt/yr	$/dkt Wellhead	$/dkt Wellhead	Gas Revenues $	G&C Oil Revenues	Operating Expense	Abandonment Costs	Royalties & Taxes (as provided)	Royalties & Taxes (calculated)	Net Revenues
2012	1,636	1,601	$1.65	$1.65	$2,641,650	$1,208,978.75	$618,703	$ -	$271,033	$271,033	$2,960,892
2013	1,348	1,326	$2.07	$2.07	$2,740,709	$1,010,133.56	$617,070	$ -	$281,197	$281,197	$2,852,576
2014	1,153	1,132	$2.28	$2.28	$2,584,130	$853,788.70	$609,420	$92,000	$265,132	$265,132	$2,471,367
2015	1,005	980	$2.43	$2.43	$2,381,400	$737,678.92	$588,239	$44,000	$244,332	$244,332	$2,242,508
2016	884	862	$2.56	$2.56	$2,208,530	$647,709.38	$573,684	$44,000	$226,595	$226,595	$2,011,960
2017	784	768	$2.71	$2.71	$2,077,670	$576,885.77	$558,955	$60,000	$213,169	$213,169	$1,822,432
2018	697	680	$2.86	$2.86	$1,946,908	$512,872.90	$513,953	$72,000	$199,753	$199,753	$1,674,075
2019	625	608	$3.03	$3.03	$1,840,720	$457,255.96	$477,827	$72,000	$188,858	$188,858	$1,559,291
2020	566	547	$3.21	$3.21	$1,755,214	$408,119.69	$447,485	$52,000	$180,085	$180,085	$1,483,763
2021	513	492	$3.38	$3.38	$1,663,108	$369,544.03	$419,070	$40,000	$170,635	$170,635	$1,402,947
2022	469	443	$3.54	$3.54	$1,567,777	$333,790.67	$392,459	$40,000	$160,854	$160,854	$1,308,255
2023	425	399	$3.69	$3.69	$1,473,587	$296,516.85	$367,538	$28,000	$151,190	$151,190	$1,223,376
2024	389	359	$3.85	$3.85	$1,380,463	$273,799.71	$344,199	$44,000	$141,635	$141,635	$1,124,428
2025	353	323	$3.85	$3.85	$1,242,032	$245,868.83	$322,342	$28,000	$127,432	$127,432	$1,010,126
2026	319	291	$3.85	$3.85	$1,118,982	$217,398.12	$301,874	$96,000	$114,808	$114,808	$823,699
2027	288	262	$3.85	$3.85	$1,007,469	$191,973.63	$282,705	$24,000	$103,366	$103,366	$789,371
2028	261	235	$3.85	$3.85	$903,646	$165,344.33	$264,753	$48,000	$92,714	$92,714	$663,523
2029	236	212	$3.85	$3.85	$815,204	$140,716.05	$247,941	$ -	$83,640	$83,640	$624,339
2030	213	191	$3.85	$3.85	$734,452	$117,951.71	$232,197	$ -	$75,355	$75,355	$544,852
2031	193	172	$3.85	$3.85	$661,392	$125,809.03	$217,452	$124,000	$67,859	$67,859	$377,890
2032	174	154	$3.85	$3.85	$592,176	$106,390.43	$203,644	$4,000	$60,757	$60,757	$430,165
2033	158	139	$3.85	$3.85	$534,497	$89,348.97	$190,713	$ -	$54,839	$54,839	$378,294
2034	143	125	$3.85	$3.85	$480,663	$102,705.39	$178,602	$100,000	$49,316	$49,316	$255,449
2035	129	113	$3.85	$3.85	$434,519	$87,628.28	$167,261	$40,000	$44,582	$44,582	$270,304
2036	117	101	$3.85	$3.85	$388,375	$74,076.28	$156,640	$4,000	$39,847	$39,847	$261,964
2037	104	91	$3.85	$3.85	$349,922	$91,084.35	$146,693	$104,000	$35,902	$35,902	$154,411
2038	94	82	$3.85	$3.85	$315,315	$79,889.14	$137,378	$24,000	$32,351	$32,351	$201,474
2039	85	74	$3.85	$3.85	$284,552	$69,035.36	$128,655	$ -	$29,195	$29,195	$195,738
2040	77	66	$3.85	$3.85	$253,790	$59,876.28	$120,485	$ -	$26,039	$26,039	$167,142
2041	70	60	$3.85	$3.85	$230,718	$50,909.23	$112,834	$80,000	$23,672	$23,672	$65,121
2042	64	54	$3.85	$3.85	$207,646	$43,617.12	$105,670	$4,000	$21,305	$21,305	$120,289
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2044	52	44	$3.85	$3.85	$169,193	$30,915.96	$92,676	$ -	$17,359	$17,359	$90,074
2045	47	39	$3.85	$3.85	$149,967	$23,926.24	$86,791	$ -	$15,387	$15,387	$71,716
2046	37	35	$3.85	$3.85	$134,586	$2,278.76	$81,279	$132,000	$13,808	$13,808	($90,224)
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2049		26	$3.85	$3.85	$99,978	$ -	$66,758		$10,258	$10,258	$22,962
2050		23	$3.85	$3.85	$88,442	$ -	$62,519		$9,074	$9,074	$16,849
2051		21	$3.85	$3.85	$80,751	$ -	$58,549		$8,285	$8,285	$13,917
2052		19	$3.85	$3.85	$73,061	$ -	$54,831		$7,496	$7,496	$10,734
2053		17	$3.85	$3.85	$65,370	$ -	$51,349		$6,707	$6,707	$7,314
2054		15	$3.85	$3.85	$57,680	$ -	$48,089		$5,918	$5,918	$3,673
2055		14	$3.85	$3.85	$53,834	$ -	$45,035		$5,523	$5,523	$3,276
2056		12	$3.85	$3.85	$46,144	$ -	$42,175		$4,734	$4,734	($766)
2057		11	$3.85	$3.85	$42,298	$ -	$39,497		$4,340	$4,340	($1,539)
2058		10	$3.85	$3.85	$38,453	$ -	$36,989		$3,945	$3,945	($2,481)
	13,766.70	13,337.00			$38,336,107	$9,840,947	$11,059,342	$1,424,000	$3,933,285	$3,933,679	$31,760,034

NorthWestern Energy

NorthWestern Corporation
d/b/a NorthWestern Energy
40 East Broadway Street
Butte, MT 59701
Telephone: (406) 497-3000
Facsimile: (406) 497-2535
www.northwesternenergy.com

April 9, 2012

Michael M. Hinze
Vice President Land
NFR Bear Paw Basin LLC
1415 Louisiana
Suite 1600
Houston, TX 77002

Re: Confidential Non-Binding Acquisition Proposal Regarding the 2012 NFR Energy LLC – Bear Paw Field Divestment Package – 3rd round bid

Dear Mr. Hinze:

NorthWestern Corporation d/b/a NorthWestern Energy ("**NorthWestern**") is pleased to submit this **3rd round** confidential, non-binding acquisition proposal on the terms hereof (the "**Proposal**") to acquire the Bear Paw Assets described in the January 2012 NFR Asset Review. It is NorthWestern's understanding that the Bear Paw Assets include 100 percent of NFR's membership and/ownership interest in: (1) the Willow Creek and Lodge Creek Gathering Systems; (2) certain operations equipment; (3) leasehold interests; and (4) the specified oil and gas reserves (collectively, but excluding the assets specifically listed in this Proposal as excluded assets, the "Bear Paw Assets").

Background to the Proposal

NorthWestern believes that its history of operating in the Bear Paw Field area will facilitate a straightforward sale process and seamless integration of the assets into our existing utility infrastructure and long standing natural gas market. A summary of NorthWestern's preliminary analysis and initial valuation of the Bear Paw Assets is set forth below.

To determine an initial valuation for the Bear Paw Assets, NorthWestern used preliminary information supplied by The Oil & Gas Asset Clearinghouse ("**O&GC**"), on behalf of **NFR Energy LLC** ("**NFR**") covering leasehold ownership information, lease operating expenses, royalty obligations, production decline curves, production taxes, property taxes and other related information. NorthWestern did not independently verify the information provided by O&GC as part of NorthWestern's preparation of the initial valuation nor does the initial valuation necessarily represent a complete valuation. With the preliminary information provided by O&GC in hand, NorthWestern performed an analysis of the Bear Paw Assets using a February 22, 2012 price forecast and estimated reserves as of January 1, 2012.

Based upon the foregoing analysis and other factors, NorthWestern's initial valuation for the Bear Paw Assets is $19,500,000.00.

NorthWestern and NFR have agreed to exclude from this 3rd round proposal certain assets that were previously included in the Bear Paw Assets described in the January 2012 NFR Asset Review provided by O&GC on behalf of NFR. The assets excluded are:

Red Rock Drilling Company
Casing inventory described by NFR and listed on the attached Exhibit A

NorthWestern's analysis and initial valuation of the Bear Paw Assets are based on the information available to date and reasonable assumptions relating to such information. Thus, NorthWestern may revise, modify, or amend its valuation and analysis as additional information becomes available and as NorthWestern conducts confirmatory due diligence concerning the Bear Paw Assets. NorthWestern is hopeful that as discussions progress, O&GC/NFR will provide NorthWestern with access to additional information so that NorthWestern may further refine its interpretations of the information and data provided to date and identify any assets or liabilities that may not have been included as part of its initial analysis.

Terms of Proposal

1. Cash Consideration: Based on the information received to date, including the Asset Review, and subject to the terms and conditions contained herein, NorthWestern is prepared to purchase the Bear Paw Assets for a cash price of $19,500,000.00. As requested by O&GC/NFR the price is divided as such:

Oil & Gas Reserves	$17,080,000
Pipeline Assets	2,420,000
Red Rock Drilling	0
Total	$19,500,000

2. **Effective Date:** NorthWestern's valuation of the Bear Paw Assets and the corresponding proposed cash consideration for such assets is based on a January 1, 2012 effective date.

3. **Structure:** NorthWestern's proposal is based on an acquisition of the Bear Paw Assets as follows: (a) oil and gas properties, leasehold interests and oil and gas reserves, pursuant to an asset sale transaction, and (b) gathering systems and operations equipment, pursuant to an acquisition of membership interests ("Gathering System Membership Interests").

4. Acquiring Entity: The proposed acquiring entity will be NorthWestern Corporation d/b/a NorthWestern Energy or a wholly owned subsidiary thereof.

5. Sources of Financing: NorthWestern intends to finance the transaction by using availability under its existing corporate revolving credit facility.

6. **Due Diligence:** NorthWestern will perform customary confirmatory due diligence concerning the Bear Paw Assets subsequent to the execution of a definitive agreement Such confirmatory due diligence will include, but not be limited to, the following areas:

   (a) legal and regulatory, including corporate, title, property and contracts;

   (b) operational, technical and environmental, including site inspections; and

   (c) financial (including access to the applicable O&GC reserve evaluation in hard copy and disc form) and tax.

   During negotiation of and promptly following the execution of the definitive agreement by NFR and NorthWestern, for the purpose of permitting NorthWestern to conduct its due diligence review of the Bear Paw Assets, NFR will permit NorthWestern and its agents and representatives to have access during normal business hours to the premises related to the operations of the Bear Paw Assets and to all of the books, records, personnel and suppliers related to such operations, and NFR will furnish NorthWestern such financial data, operating data and other information related to such operations as NorthWestern may reasonably request. Any field visit prior to the execution of a definitive agreement will require execution of a mutually agreeable indemnity in favor of NFR.

7. **Definitive Agreement**: Consummation of the transaction will be subject to the negotiation and execution of a definitive agreement with terms satisfactory to NFR and NorthWestern and which reflect the provisions summarized above and below. This letter does not set forth all of the matters upon which agreement must be reached in order for the proposed transaction to be consummated.

   a. **Representations and warranties**: The definitive agreement will contain representations, warranties and covenants customary in transactions of this type.

   b. **Employees**: NorthWestern may be interested in offering employment to those current NFR employees who are integral to the ongoing operation of the Bear Paw Assets. NFR will agree to co-operate in scheduling interviews with employees as requested by Northwestern, but the definitive agreement will provide no terms upon which NorthWestern will hire such employees, if any.

   c. **Conditions to Closing**: The transaction shall have been approved by the respective Boards of Directors of NFR and NorthWestern, by the later of the execution of the definitive agreement or April 24, 2012. The definitive agreement shall provide that the closing of the transaction contemplated thereby will be subject to appropriate conditions, including, without limitation, the following:

      i. All required approvals, consents and authorizations of state and Federal regulatory authorities, if any, shall have been received.

      ii. In the event a member exercises its "tag along" rights to NorthWestern's acquisition of the Gathering System Membership Interests, NorthWestern will

acquire the other member's offered membership interest with respect to the gathering system and operations equipment.

8. **Exclusivity:** During the period ("**Exclusivity Period**") commencing on the date that both parties have executed this letter of intent (the "Execution Date") and ending on the earlier of (i) the 45th day following the Execution Date, (ii) the execution of the definitive agreement by NFR and NorthWestern concerning the transaction described in this letter agreement or (iii) the date of written termination of discussions or negotiations by NFR or NorthWestern, neither NFR nor its representatives or agents will solicit offers from, negotiate with or provide financial or operating information to, any other party for the purpose of determining any interest in acquiring the Bear Paw Assets. NFR will immediately cease all discussions with any third parties concerning an acquisition transaction of the Bear Paw Assets, and during the Exclusivity Period, NFR shall negotiate exclusively with NorthWestern concerning the sale of the Bear Paw Assets.

9. **Expenses:** Each of the parties will bear its own expenses relating to the proposed transaction, whether or not a definitive agreement is signed and whether or not the closing of the transaction occurs.

10. **Public Disclosure:** Except as required by law, the timing and content of any public disclosure shall be made only upon the mutual approval of NFR and NorthWestern. Both parties recognize the date of execution of definitive agreement currently represents the most appropriate date for an announcement.

11. **Enforceability:** This letter is an expression of intent only and is not legally binding upon either of the parties hereto, except that the provisions of Paragraphs 6, 7, 8, 9, 10, 11, 12, 13 and 14 of this letter shall be legally binding upon and enforceable against each of the parties hereto; provided, however, upon termination, only the provisions of Paragraphs 9, 10, 11 and 14 shall survive. Neither party shall have any obligation to continue discussions or negotiations if such party determines such termination is in such party's best interests. Accordingly, either party may, in its sole discretion, abandon or terminate these discussions or any negotiations at any time or for any reason, without liability to the other party for costs or expenses of any sort incurred by the other party in pursuing the transactions contemplated hereby.

12. **Counterparts:** This letter of intent may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. Electronic copies of signatures shall be treated as originals for all purposes.

13. **Headings:** The heading references herein are for convenience only, do not constitute a part of this letter of intent, and shall not limit or affect any provision hereof.

14. **Prior Agreements:** This letter of intent contains the entire agreement by and among the parties to date with respect to the subject matter hereof and supersedes any and all prior agreements and understandings, oral or written, with respect to such matters.

If the foregoing meets with your approval, please indicate your acceptance and, with respect to paragraphs 6, 7, 8, 9, 10, 11, 12, 13 and 14 only, your agreement, by signing and returning the accompanying copy of this letter.

Contact Information

NorthWestern representatives to be contacted by O&GC/NFR in respect of this Proposal are:

Bleau LaFave
Director Long Term Growth
NorthWestern Energy
3010 West 69th St.
Sioux Falls, SD 57108
Office: (605) 978-2897
Fax: (605) 782-5404
Bleau.LaFave@northwestern.com

Pat Callahan
Director, Gas Growth
NorthWestern Energy
40 E. Broadway
Butte, MT 59701
Office: (406) 497 - 2137
Fax: (406) 497-3480
pat.callahan@northwestern.com

Confidentiality

This Proposal is being communicated by NorthWestern to O&GC, on behalf of NFR, solely for the purpose of determining whether to proceed toward a mutually agreeable transaction. O&GC and NFR shall keep the fact that this Proposal has been made and its terms strictly confidential and further shall not disclose any of this information to any other person, either directly or indirectly, including without limitation, through communication of a range of price level, general terms, timing or otherwise, with a view to inducing that person to make an offer or to improve any offer previously made.

Miscellaneous

This Proposal is intended as a non-binding statement of NorthWestern's intention to proceed in good faith as outlined above and is not intended to, and does not create binding or enforceable legal obligations or duties between NorthWestern and NFR, except as set forth in Paragraph 11.

NorthWestern looks forward to continuing to work closely with you to effect a mutually beneficial transaction.

Very truly yours,

NORTHWESTERN CORPORATION
d/b/a NORTHWESTERN ENERGY

By:
Name: Robert C. Rowe
Title: President and CEO

ACCEPTED AND, WITH RESPECT
TO PARAGRAPHS 6, 7, 8, 9, 10, 11, 12, 13 AND 14,
AGREED TO, THIS ___ DAY OF APRIL, 2012

NFR ENERGY LLC

By: _____
Name: Michael Rinze
Title: Vice President Land

Exhibit A

Item ID	Item Description	Amount	Joints
29539	2008 4 ½" Production Casing	46285.88	1062

Exhibit__(PEC-10) and Exhibit__(PEC-11)

have been provided only on the attached CD.

CONFIDENTIALITY AGREEMENT

This Confidentiality Agreement (this "Agreement") is made and entered into effective August 14, 2012, by and between Devon Energy Production Company, L.P. ("Devon"), an Oklahoma limited partnership, and NorthWestern Corporation d/b/a NorthWestern Energy ("Recipient"). Devon and Recipient are sometimes referred to in this Agreement individually as a "Party" and collectively as the "Parties".

Recitals

A. Recipient has requested permission to examine certain information (the "Evaluation Material") in the possession of Devon relating to the oil and gas properties and midstream assets located in the geographic areas described in Exhibit "A" attached hereto and made a part hereof (the "Properties") for the sole purpose (the "Purpose") of enabling Recipient to evaluate such Properties and the related rights and interests of Devon in the Properties (as applicable) in order to determine whether Recipient wants to make an offer to acquire such Properties and the related rights and interests of Devon (the "Potential Transaction").

B. Devon has agreed to allow Recipient access to the Evaluation Material, but only for the Purpose and only in connection with the Potential Transaction, subject to the terms and conditions set forth below.

Agreement

As a condition to, and in consideration of Recipient receiving access to the Evaluation Material and any other Confidential Information (defined below), the Parties agree as follows:

1. The Evaluation Material, any other information obtained by Recipient directly or indirectly from Devon or its Affiliates (defined below) or any of their employees, consultants, agents, or representatives, and any analyses, notes, compilations, reports, studies, interpretations, or other documentation prepared by Recipient or its directors, officers, employees, attorneys, consultants, agents, or other representatives (collectively, "Representatives") based upon, in whole or in part, any Evaluation Material or other information provided by Devon or its Affiliates in connection with the Properties are herein collectively referred to as the "Confidential Information". Such Confidential Information includes, by way of illustration but not limitation, and irrespective of the form of communication (whether oral, written, or in electronic format), the following: (a) the Purpose; (b) that discussions or negotiations are taking place between the Parties as to the Potential Transaction; (c) any terms, conditions, or other facts regarding the Potential Transaction or its status; (d) geological and geophysical information; (e) well and log data; (f) maps, reports, interpretations, and charts; (g) production, engineering, and other technical data; (h) title, land, and right-of-way information; (i) know-how; (j) trade secrets; and (k) financial and budget information. Certain of the Evaluation Material may be licensed from one or more third parties ("Speculative Data") and/or is subject to certain confidentiality obligations between Devon and its Affiliates and one or more third parties ("Data Subject to Independent Confidentiality Obligations").

2. Notwithstanding anything to the contrary in Paragraph 1, the term "Confidential Information" will not include information that: (a) is or becomes generally

available to the public other than through the act or omission of Recipient or its Representatives; (b) is known to Recipient at the time of disclosure and is not subject to a prior confidentiality agreement with Devon; (c) is acquired at any time from a source other than Devon that was not prohibited from making such disclosure; or (d) is independently developed by or for Recipient prior to the date on which Devon delivers or otherwise makes such Confidential Information available to Recipient.

3. Recipient will use the Confidential Information solely for the Purpose and will not use, and will ensure that its Representatives do not use, any portion of the Confidential Information for any other purpose. Recipient will not disclose, and will ensure that its Representatives do not disclose, any Confidential Information. Recipient will take all necessary and appropriate measures to safeguard the Confidential Information from disclosure or use other than as permitted in this Agreement. In complying with the foregoing, Recipient will limit access to the Confidential Information to such of its Representatives who have a bona fide need to review such Confidential Information for the Purpose and who are informed by Recipient of the confidential nature of the Confidential Information. If requested by Devon, Recipient will provide a list of its Representatives who have received the Confidential Information. Recipient will be responsible for any disclosure or use of Confidential Information by its Representatives that would be a breach of this Agreement had such disclosure or use been made by Recipient, and any such disclosure or use by Recipient's Representatives will be deemed a breach by Recipient of its obligations hereunder.

4. Recipient is aware, and will ensure that its Representatives to whom any Confidential Information is disclosed are also aware, of the general nature of applicable securities laws, including, without limitation, all applicable securities laws that may prohibit a person who has material, non-public information concerning the matters that are the subject of this Agreement from: (a) trading in securities of a party to the Potential Transaction or their Affiliates; or (b) communicating such information to another person. For purposes of this Agreement, the term "Affiliates" includes, with respect to any person, any other person directly or indirectly controlling, controlled by, or under common control with, such person. As used in the foregoing sentence, the term "control" and variations thereof means the power to direct the management and policies of such other person, whether through ownership of voting securities, by contract, or otherwise. Additionally, the term "person" means any corporation, trust, partnership, limited liability company, unincorporated organization, association, joint venture, governmental body, or individual.

5. The obligations of Recipient contained in Paragraph 3 of this Agreement will continue for the longer of: (a) a period of two (2) years from the effective date of this Agreement; or (b) as to Speculative Data and Data Subject to Independent Confidentiality Obligations, until, as applicable, Recipient receives a license to use the Speculative Data, if ever, or the confidentiality obligations of Devon with respect to the Data Subject to Independent Confidentiality Obligations have terminated. Recipient agrees that its and its Representatives' access to and review of all Speculative Data and Data Subject to Independent Confidentiality Obligations will be further subject to and limited by all applicable licensing agreements and contracts.

6. Recipient will not reproduce or remove any Confidential Information from the Data Room, Devon's offices, or any other Devon facility without Devon's express permission. The Confidential Information will at all times remain the sole, absolute, and exclusive property of Devon. Devon does not grant to Recipient any right, title, or interest of any kind

in or relating to the Confidential Information, and Recipient agrees to make no claim to any such right, title, or interest.

7. Recipient understands and agrees that Devon is making no express warranty and disclaims all implied warranties as to: (a) the accuracy or completeness of the Confidential Information, including the Evaluation Material; (b) the presence of hydrocarbons on or under the Properties; and (c) the results that might be expected from any exploration, development, production, financing, and/or hydrocarbon marketing activities involving or associated with any or all of the Properties. Notwithstanding the foregoing in this Paragraph 7, in providing any Confidential Information to Recipient, Devon represents that it has the right and authority to do so (qualified, as to certain Confidential Information, by the requirement for Recipient to enter into this Agreement). The only specific representations and warranties that will have legal effect between the Parties are those contained in the immediately preceding sentence and those contained in a definitive agreement relating to the Potential Transaction (when and if a definitive agreement is fully executed and delivered).

8. Recipient agrees that: (a) it and its Representatives will use the Confidential Information at their sole risk; (b) it will rely solely on its own independent evaluation and examination of the Properties in making its determination whether to proceed with the Potential Transaction; and (c) Devon will have no liability whatsoever with respect to the use by Recipient or its Representatives of such Confidential Information, other than any liability arising pursuant to the terms of any definitive agreement relating to the Potential Transaction (when and if a definitive agreement is fully executed and delivered). Recipient hereby releases Devon, its Affiliates, and their respective directors, officers, employees, consultants, agents, and representatives (the "Indemnified Parties") from, and agrees to defend, indemnify, and hold harmless all Indemnified Parties from and against, any and all claims, liabilities, losses, or damages resulting in any way from or attributable to such use by Recipient.

9. In the event any of Recipient's Representatives is permitted at any time to visit any of the Properties, such visit will be conducted at the sole cost and expense of Recipient. Recipient hereby agrees to defend, indemnify, and hold harmless all Indemnified Parties from and against any and all claims for injury, death, property damage, or other loss resulting from or attributable to any such visit, unless caused by the gross negligence or willful misconduct of the Indemnified Parties.

10. Recipient agrees that, for a period of one (1) year from the effective date of this Agreement, neither Recipient nor any of its Affiliates will solicit for employment any Devon employee whose job requirements include responsibility for any or all of the Properties so long as they are employed by Devon, without obtaining the prior written consent of Devon; provided, however, that the foregoing will not apply to public solicitations for or general advertising of employment opportunities with Recipient.

11. Recipient acknowledges that Devon, in its sole and absolute discretion: (a) is free to explore other potential opportunities that may lead to a possible transaction with another party with respect to the Properties; (b) may change the procedures relating to its consideration of a transaction involving the Properties at any time without prior notice; (c) may reject any and all proposals made by Recipient with respect to the Potential Transaction; (d) may terminate discussions with Recipient at any time and for any reason; and (e) will have no obligation or liability to Recipient with regard to the Potential Transaction by virtue of this

Agreement or otherwise, unless and until, and only in the event that, a definitive agreement is executed with respect to the Potential Transaction. Accordingly, Devon may elect at any time to terminate further access to and review of the Confidential Information, at which time the obligations of Recipient contained in Paragraph 12 below will be applicable.

12. If Recipient decides that it does not wish to proceed in connection with the Potential Transaction, it will promptly inform Devon of such decision. In that case, or at any time upon the request of Devon for any reason, Recipient, at its option, will either: (a) promptly deliver to Devon all Confidential Information (and all copies thereof); or (b) promptly destroy all Confidential Information without retaining any copies, summaries, or extracts thereof, including, without limitation, electronic copies or copies stored on any recordable media, and confirm in a writing by a duly authorized officer of Recipient that the Confidential Information has been destroyed, provided that such obligation to destroy will not require Recipient to identify and remove any Confidential Information that may exist in data form on Recipient's back-up media so long as Recipient agrees not to, and does not, access such data for any purpose. Notwithstanding the return or destruction of the Confidential Information, Recipient and its Representatives will continue to be bound by the obligations of confidentiality and other obligations set forth in this Agreement.

13. Recipient acknowledges and agrees that money damages may be inadequate to protect Devon against any actual or threatened breach of this Agreement by Recipient or its Representatives, and, accordingly, Recipient agrees that Devon will be entitled to seek specific performance and injunctive relief in its favor without proof of immediate, irreparable, and/or actual damages. Such remedies will not be deemed to be the exclusive remedies for a breach of this Agreement by Recipient or any of its Representatives but will be in addition to all other remedies available to Devon at law or in equity. Recipient further agrees to waive, and use its best efforts to cause its Representatives to waive, any requirement for securing or posting any bond in connection with the pursuit of any such remedy. In the event of litigation relating to this Agreement, if a court of competent jurisdiction determines in a final, non-appealable order that this Agreement has been breached by Recipient or its Representatives, then Recipient will reimburse Devon for its costs and expenses (including, without limitation, legal fees and expenses) incurred in connection with any such litigation as concerns such breach, including, without limitation, in connection with any appeal therefrom.

14. If Recipient or any of its Representatives is required by any court or legislative or administrative body (by oral questions, interrogatories, requests for information or documents, subpoena, or similar process) to disclose any Confidential Information, Recipient will promptly provide Devon with written notice of such requirement so that Devon may have an opportunity to seek an appropriate protective order. Recipient and its Representatives agree to cooperate with any reasonable request of Devon in its efforts to secure such protective order or other appropriate remedy. If Devon is unable to obtain such protective order or other appropriate remedy, Recipient or its Representatives will furnish only that portion of the Confidential Information that Recipient or its Representatives are advised by counsel is required by law to be furnished and will exercise their reasonable efforts to obtain assurance that confidential treatment will be accorded such Confidential Information.

15. No failure or delay by Devon in exercising any right, power, or privilege hereunder will be deemed a waiver thereof or preclude exercise of any other or further right, power, or privilege hereunder. No amendments, changes, or modifications to this Agreement

will be valid unless in writing and signed by a duly authorized representative of the Parties. This Agreement comprises the full and complete agreement of the Parties with respect to the subject matter hereof, and supersedes and replaces any oral or written communications, understandings, and agreements heretofore made between the Parties with respect to such subject matter. This Agreement will inure to the benefit of Devon and its successors and assigns, and will be binding upon Recipient and its Representatives and their respective heirs, representatives, successors, and assigns, provided that Recipient may not assign any of its rights or obligations hereunder to any third party without the prior written consent of Devon. Any attempted assignment without such consent will be null and void. This Agreement will be governed by and construed in accordance with the substantive laws of the State of Oklahoma. This Agreement may be executed in multiple counterparts, each of which will be deemed an original, but all of which together will constitute a single agreement. This Agreement may be validly executed and delivered by facsimile or other electronic transmission.

16. Notices to either Party with regard to any matter covered by this Agreement will be made in writing and will be deemed to have been duly given or made if: (a) delivered personally; (b) transmitted by first class registered or certified mail, posted prepaid, return receipt requested; (c) sent by recognized prepaid overnight courier service (which provides a receipt); or (d) sent by facsimile or electronic mail transmission (followed by delivery under one of the methods provided for in (a), (b), or (c) above) with receipt confirmation, to the Parties at the addresses set forth below:

Devon:	Recipient:
333 West Sheridan Avenue Oklahoma City, Oklahoma 73102-5015	9 W. Granite Street Butte, MT 59701
Attention: Aaron Ketter Facsimile: 405.552.7613 Email: aaron.ketter@dvn.com	Attention: Patrick Callahan Facsimile: 406.497.3480 Email: patrick.callahan@northwestern.com

Such notice will be effective only upon actual receipt.

The remainder of this page is intentionally blank
Signature page follows

In Witness Whereof, the duly authorized representatives of the Parties have executed this Agreement, effective as of the day and year first above written.

Devon Energy Production Company, L.P.

By: _____
Name: Tom Hooper
Title: VP, Acquisitions + Divestitures

NorthWestern Energy

By: _____
Name: Bleau LaFave
Title: Director Long Term Resources

Exhibit A

Bear Paw

Devon's Bear Paw properties and assets located in Blaine, Chouteau, and Hill Counties, Montana, including leases, gathering systems, pipelines, equipment, facilities, and other interests relating thereto.

UA_API		UA_OPERATOR	UA_PROPERTY_NAME	WI_OPERATING_FINAL	NRI_GAS_FINAL	NRI_OIL_FINAL
X	OP	DEVON	2012 BEAR PAW P&A WELLS	100	100	100
25005220980000	OP	DEVON	AARSTAD 14-16-26-18	53.6439	43.9033	43.9033
25041231310000	OP	DEVON	ANDERSON 30-01-31-16	93.1935	77.8471	77.8471
25041226270000	OP	DEVON	ANDERSON 30-10-31-16 BHU	93.1935	77.8471	77.8471
25041210070000	OP	DEVON	ANDERSON 30-11-31-16	93.1935	77.8471	77.8471
25041222780000	OP	DEVON	ARMSTRONG 19-02-31-16	93.1935	77.8471	77.8471
25041225930000	OP	DEVON	ARMSTRONG 19-15-31-16	93.1935	77.8471	77.8471
25041225390000	OP	DEVON	BERGER 24-16-31-14 BHU	93.1935	77.8471	77.8471
25041226730000	OP	DEVON	BERGER 25-01-31-14	93.1935	77.8471	77.8471
25005218790000	OP	DEVON	BIEBINGER 05-17-26-18	53.6439	43.7532	43.7532
25005237420000	OP	DEVON	BIEBINGER 07-07-25-18	53.6439	43.7582	43.7582
25005221650000	OP	DEVON	BIEBINGER 13-16-26-17 (NC)	53.7088	42.9799	42.9799
25005227850000	OP	DEVON	BIEBINGER 18-02-26-18	53.6439	43.7532	43.7532
25005214570000	OBO	NFR BEAR PAW BASIN, LLC	BIEBINGER 72-2	9.3889	7.1334	7.1334
25005222090000	OP	DEVON	BJORNSON 12-34 (34-12-32-19)	100	87.802	87.802
25005226840000	OP	DEVON	BJORNSON 15-27 (27-15-32-19)	100	87.8021	87.8021
25005051370000	OP	DEVON	BJORNSON 2 (34-03-32-19)	100	87.802	87.802
25005223600000	OP	DEVON	BLACKWOOD 02-08-30-18	84.912	70.1643	70.1643
25005226680000	OP	DEVON	BLACKWOOD 02-13-30-17	84.912	70.1643	70.1643
25005227090000	OP	DEVON	BLACKWOOD 03-10-30-17	84.912	70.1643	70.1643
25005223960000	OP	DEVON	BLACKWOOD 03-16-30-17	84.912	70.1643	70.1643
25005214340000	OP	DEVON	BLACKWOOD 04-10-30-18	84.912	70.1643	70.1643
25005228480000	OP	DEVON	BLACKWOOD 05-11-30-18	84.912	70.1643	70.1643
25005228540000	OP	DEVON	BLACKWOOD 05-13-30-18	84.912	70.1643	70.1643
25005226510000	OP	DEVON	BLACKWOOD 05-14-30-18	84.912	70.1643	70.1643
25005223950000	OP	DEVON	BLACKWOOD 05-15-30-18	84.912	70.1643	70.1643
25005221610000	OP	DEVON	BLACKWOOD 06-09-30-18	84.912	70.1643	70.1643
25005225130000	OP	DEVON	BLACKWOOD 01-13-30-17	84.912	70.1643	70.1643
25005211450000	OP	DEVON	BLACKWOOD 07-06-30-18	84.912	70.1643	70.1643
25005227960000	OP	DEVON	BLACKWOOD 07-15-30-18	84.912	70.1643	70.1643
25005229320000	OP	DEVON	BLACKWOOD 08-03-30-18	84.912	70.1643	70.1643
25005222770000	OP	DEVON	BLACKWOOD 08-05-30-18	84.912	70.1643	70.1643
25005228510000	OP	DEVON	BLACKWOOD 08-12-30-18	84.912	70.1643	70.1643
25005227680000	OP	DEVON	BLACKWOOD 11-03-30-17	84.912	70.1643	70.1643
25005227080000	OP	DEVON	BLACKWOOD 11-08-30-17	84.912	70.1643	70.1643
25005214050000	OP	DEVON	BLACKWOOD 12-01-30-17	84.912	70.1643	70.1643
25005219460000	OP	DEVON	BLACKWOOD 07-01-30-18	84.912	70.1643	70.1643
25005230410000	OP	DEVON	BLACKWOOD 12-04-30-17	84.912	70.1643	70.1643
25005223300000	OP	DEVON	BLACKWOOD 12-06-30-17	84.912	70.1643	70.1643
25005219180000	OP	DEVON	BLACKWOOD 34-09-31-18	84.912	70.1643	70.1643
25041213370000	OP	DEVON	BLAIR LARSON 10-22-32-15 (NWSE)	98.745	81.467	81.467
25005215150000	OP	DEVON	BLAKEWAY 15-3 (03-15-31-19)	100	45	45
25005228630000	OP	DEVON	BLACKWOOD 12-03-30-17	84.912	70.1643	70.1643
25041228320000	OP	DEVON	BOYCE 35-04A-30-15	94.2731	78.2785	78.2785
25041233190000	OP	DEVON	BOYCE-DIR 23-15-30-15	93.1935	77.8471	77.8471
25005232240000	OP	DEVON	BRAUN 35-01-32-19	100	87.5	87.5
25005231860000	OP	DEVON	BRAUN 35-12-32-19	100	87.5	87.5
25015212340000	OP	DEVON	BOYCE 2-24 (24-10-27-16)	100	86.4375	86.4375
25041225190000	OP	DEVON	BOYCE 21-08-30-15	93.1935	77.8471	77.8471
25041226130000	OP	DEVON	BOYCE 21-09-30-15 BHU	93.1935	77.8471	77.8471
25041224070000	OP	DEVON	BOYCE 21-14-30-15	93.1935	77.8471	77.8471
25041220100000	OP	DEVON	BOYCE 21-15-30-15	93.1935	77.8471	77.8471
25041214650000	OP	DEVON	BOYCE 22-15-30-15 BHU	93.1935	77.8471	77.8471
25005235150000	OP	DEVON	BRAUN 35-13-32-19	100	87.5	87.5
25005222470000	OP	DEVON	BRECK 13-10-25-17	51.9094	43.7119	43.7119
25041224080000	OP	DEVON	BOYCE 23-01-30-15	93.1935	77.8471	77.8471
25041227580000	OP	DEVON	BOYCE 24-03-30-15	85.746	72.6785	72.6785
25041224360000	OP	DEVON	BOYCE 24-04-30-15	85.746	72.6785	72.6785
25041224720000	OP	DEVON	BOYCE 26-13-30-15	68.6181	57.1122	57.1122
25041226150000	OP	DEVON	BOYCE 27-02-30-15 BHU	93.1935	77.8471	77.8471
25041227710000	OP	DEVON	BROWN 06-10-30-15	93.1935	77.8471	77.8471
25041223180000	OP	DEVON	BROWN 06-16-30-15	93.1935	77.8471	77.8471
25041229250000	OP	DEVON	BROWN 24-03-31-14	93.1935	77.8471	77.8471
25005222720000	OP	DEVON	BOGGESS 01-13-25-17	52.5572	42.9007	42.9007
25005225750000	OP	DEVON	BOGGESS 02-02-25-17	54.2684	44.3524	44.3524
25005222590000	OP	DEVON	BOGGESS 03-02-25-17	53.1538	44.0562	44.0562
25005237400000	OP	DEVON	BOGGESS-DIR 02-12-25-17	59.9363	49.6787	49.6787
25015211950000	OP	DEVON	BOYCE 1-22 (22-06-27-16)	100	86.375	86.375
25041233140000	OP	DEVON	BOYCE 13-12-30-15	93.6949	79.2422	79.2422
25041224340000	OP	DEVON	BOYCE 13-13-30-15	94.3374	78.534	78.534
25041225660000	OP	DEVON	BOYCE 13-14-30-15	77.1811	60.6101	60.6101
25041223190000	OP	DEVON	BOYCE 14-16-30-15	93.1935	77.8471	77.8471
25041225250000	OP	DEVON	BOYCE 27-03-30-15	93.1935	77.8471	77.8471
25041223200000	OP	DEVON	BOYCE 27-04-30-15	93.1935	77.8471	77.8471
25041224650000	OP	DEVON	BOYCE 27-05-30-15	93.1935	77.8471	77.8471
25041221040000	OP	DEVON	BOYCE 27-07-30-15	93.1935	77.8471	77.8471
25041227620000	OP	DEVON	BOYCE 27-13-30-15	93.1935	77.8471	77.8471
25041228880000	OP	DEVON	BOYCE 27-13B-30-15	93.1935	77.8471	77.8471
25041232250000	OP	DEVON	BOYCE 19-03-30-16	54.1838	45.9532	45.9532
25041224690000	OP	DEVON	BOYCE 19-04-30-16	76.6364	64.9106	64.9106

25041230580000	OP	DEVON	BOYCE 19-06-30-16	76.5987	64.9106	64.9106
25041229120000	OP	DEVON	BOYCE 19-10-30-16	77.4102	64.5038	64.5038
25041230510000	OP	DEVON	BOYCE 19-14A-30-16	76.5987	65.6091	65.6091
25041230480000	OP	DEVON	BOYCE 19-15-30-16	76.5987	64.5038	64.5038
25041227970000	OP	DEVON	BOYCE 27-14-30-15	93.1935	77.8471	77.8471
25041223870000	OP	DEVON	BOYCE 27-15-30-15	93.1935	77.8471	77.8471
25041225770000	OP	DEVON	BOYCE 27-3B-30-15	93.1935	77.8471	77.8471
25041224640000	OP	DEVON	BOYCE 28-03-30-15	93.1935	77.8471	77.8471
25041227980000	OP	DEVON	BOYCE 28-09-30-15	93.1935	77.8471	77.8471
25041224320000	OP	DEVON	BOYCE 28-11-30-15 (JR)	93.1935	77.8471	77.8471
25041229100000	OP	DEVON	BOYCE 33-02-30-15	94.6297	78.2901	78.2901
25041224370000	OP	DEVON	BOYCE 34-01-30-15	94.2731	78.2785	78.2785
25041224490000	OP	DEVON	BOYCE 34-03-30-15	94.2731	78.2785	78.2785
25041229110000	OP	DEVON	BOYCE 34-03B-30-15	93.6693	79.5799	79.5799
25041233060000	OP	DEVON	BOYCE 34-04-30-15	94.2731	78.2785	78.2785
25041224190000	OP	DEVON	BOYCE 35-04-30-15	94.2731	78.2785	78.2785
25005212720000	OP	DEVON	BARBER 1-33 (33-11-28-19)	90.625	78.2553	78.2553
X	OP	DEVON	BEAR PAW - AD VAL	100	100	100
X	OP	DEVON	BEAR PAW HEAVY EQUIPMENT 2012	100	100	100
X	OP	DEVON	BEAR PAW-BULLHOOK - P&A AND EQUIP U&R PROJECTION	90.2109	75.4271	75.4271
X	OP	DEVON	BEAR PAW-BULLWACKER - P&A AND EQUIP U&R PROJ	98.7092	85.1655	85.1655
X	OP	DEVON	BEAR PAW-SAWTOOTH - P&A AND EQUIP U&R PROJECTION	88.7328	75.6479	75.6479
X	OP	DEVON	BEAR PAW-SHERARD - P&A AND EQUIP U&R PROJECTION	53.4017	43.4534	43.0138
X	OP	DEVON	BEAR PAW-TIGER RIDGE- P&A AND EQUIP U&R PROJ	82.3958	69.0745	69.0745
25041225400000	OP	DEVON	BECK 10-05-31-15	93.1935	77.8471	77.8471
25041223650000	OP	DEVON	BECKER 24-01-31-14	93.1935	77.8471	77.8471
25041226160000	OP	DEVON	BECKER 24-07-31-14 BHU	93.1935	77.8471	77.8471
25041227280000	OP	DEVON	BECKER 30-03-31-15	93.1935	77.8471	77.8471
25005224950000	OBO	BROWN J BURNS OPERG CO	BENNETT 15-32-18	0.6738	0.5896	0.5896
25005227230000	OP	DEVON	BENSON 13-05-31-18	83.5466	68.9506	68.9506
25041215740000	OP	DEVON	BERG 08-7X-31-15	93.1935	77.8471	77.8471
25041227640000	OP	DEVON	BERG 32-12-32-14	95.7038	83.7408	83.7408
25041226820000	OP	DEVON	BERG 32-13-32-14	95.7038	83.7408	83.7408
25041226790000	OP	DEVON	BERGER 19-10-31-15	93.1935	77.8471	77.8471
25041211750000	OP	DEVON	BERGER 24-11-31-14 BHU	93.1935	77.8471	77.8471
25041226210000	OP	DEVON	BERGER 24-15-31-14 BHU	93.1935	77.8471	77.8471
X	OP	DEVON	2011 BEAR PAW EQUIP UPGRADE	100	100	100
X	OP	DEVON	2011 BEAR PAW FACILITIES	100	100	100
X	OP	DEVON	2011 BEAR PAW P&A WELLS	100	100	100
X	OP	DEVON	2012 BEAR PAW EQUIP UPGRADE	100	100	100
25005225850000	OP	DEVON	COLUMBIAN 14-10 (10-14-31-19)	100	87.5	87.5
25005216840000	OP	DEVON	COLUMBIAN 15-10 (10-15-31-19)	100	87.5	87.5
25005237010000	OP	DEVON	COURTNAGE-STATE 35-08-25-17	55.6858	45.9347	45.9347
25041229000000	OP	DEVON	CREMER 34-02-31-17	84.912	70.1643	70.1643
25041225160000	OP	DEVON	CREMER 34-14-31-17	84.912	70.1643	70.1643
25041224840000	OP	DEVON	CROWE 23-08-31-15 (WO)	93.1935	77.8471	77.8471
25041235360000	OP	DEVON	CROWE-DIR 14-11-31-15	93.1935	77.8471	77.8471
25041235460000	OP	DEVON	CROWE-DIR 15-16-31-15	93.1935	77.8471	77.8471
25041234470000	OP	DEVON	CROWE-DIR 23-01-31-15	91.6329	74.1164	74.1164
25041235390000	OP	DEVON	CROWE-DIR 23-04-31-15	93.1935	77.8471	77.8471
25041235220000	OP	DEVON	DAHLIN 20-01-31-15	93.1935	77.8471	77.8471
25041226170000	OP	DEVON	DAHLIN 20-04-31-15 BHU	93.1935	77.8471	77.8471
25041224590000	OP	DEVON	DAHLIN 20-12-31-15	93.1935	77.8471	77.8471
25041226860000	OP	DEVON	DANIEL 03-06-31-14	94.9878	78.0636	78.0636
25041226290000	OP	DEVON	DANIEL 28-16-32-14	94.9878	79.8725	79.8725
25041227590000	OP	DEVON	DANIEL 33-12-32-14	94.9878	78.1517	78.1517
25041226000000	OP	DEVON	DANIEL 33-15-32-14	94.9878	78.1517	78.1517
25041217780000	OP	DEVON	DANIEL 34-03-32-14	94.9878	77.0269	77.0269
25041225720000	OP	DEVON	DANIEL 34-13-32-14	94.9878	77.0269	77.0269
25041222280000	OBO	SECTOR RESOURCES	DAVEY 01-29 NE NE	35.2984	27.4552	27.4552
25005225090000	OP	DEVON	DAVEY 06-04-31-18	84.912	70.1643	70.1643
25041229220000	OP	DEVON	DAVEY 15-13-32-17	98.0652	85.4165	85.4165
25041224890000	OP	DEVON	CHIP CREE 08-04-30-15	93.1935	77.8471	77.8471
25041225150000	OP	DEVON	CHIP CREE 20-08-30-15	93.1935	77.8471	77.8471
25041224900000	OP	DEVON	CHIP CREE 21-04-30-15	93.1935	77.8471	77.8471
25041224670000	OP	DEVON	CHIP CREE 22-04-30-15	93.1935	77.8471	77.8471
25041224680000	OP	DEVON	CHIP CREE 22-14-30-15	93.1935	77.8471	77.8471
25041223380000	OP	DEVON	CITY OF HAVRE SENWNE	100	84	84
25041231060000	OP	DEVON	CLAYBORN 19-12-30-16	76.5987	65.6091	65.6091
25041231240000	OP	DEVON	CLAYBORN 19-13-30-16	76.5987	65.6091	65.6091
25041232740000	OP	DEVON	CLAYBORN-DIR 18-13-30-16	54.1838	45.9532	45.9532
25041232730000	OP	DEVON	CLAYBORN-DIR 18-14-30-16	54.1838	45.9532	45.9532
25041227730000	OP	DEVON	BUTTREY 14-08-32-15	100	84.5551	84.5551
25005212690000	OP	DEVON	CAMPBELL 08-06-27-19	100	86.7735	86.7735
25005229170000	OP	DEVON	CAMPBELL 09-14-27-19	100	87.2265	87.2265
25005210840000	OP	DEVON	CAMPBELL 2-4 (04-06-27-19)	73.0552	64.0845	64.0845

25005212700000	OP	DEVON	CAMPBELL 2-9 (09-15-27-19)	100	87.2265	87.2265
25005224020000	OP	DEVON	CAMPBELL 2A-9 (09-2-27-19)	100	87.2265	87.2265
25005223990000	OP	DEVON	CAMPBELL 9-4 (04-09-27-19)	73.0552	64.0845	64.0845
25005217380000	OP	DEVON	HILLER 04-01-31-18	84.912	70.1643	70.1643
25005224900000	OP	DEVON	HILLER 10-01-31-18	82.7634	68.7339	68.7339
25005221560000	OP	DEVON	HILLER 33-10-32-18	84.912	70.1643	70.1643
25005215940000	OP	DEVON	HILLER 34-12-32-18	73.0194	61.2395	61.2395
25005050430000	OP	DEVON	HOBSON 2 (09-01-31-19)	100	100	100
25041233970000	OP	DEVON	HOCKETT 01-06-31-14	93.1935	77.8471	77.8471
25041233020000	OP	DEVON	HOCKETT 26-05-32-14	93.1935	77.8471	77.8471
25041214770000	OP	DEVON	HOCKETT 35-10-32-14 BHU	93.1935	77.8471	77.8471
25005226690000	OP	DEVON	HOFELDT 02-13-30-18	84.912	70.1643	70.1643
25005236690000	OP	DEVON	HOFELDT 02-16-30-18	84.912	70.1643	70.1643
25005223280000	OP	DEVON	HOFELDT 03-16-30-18	84.912	70.1643	70.1643
25005232600000	OP	DEVON	KANE 11-09-26-17	49.4094	42.8068	42.8068
25015217790000	OP	DEVON	KANE 21-14-27-16	100	86.5	86.5
25015216880000	OP	DEVON	KANE 28-02-27-16	100	86.5	86.5
25015215960000	OP	DEVON	KANE 3-28 (28-03-27-16)	100	86.5	86.5
25005236850000	OP	DEVON	KANE 32-10A-31-18	84.912	70.1643	70.1643
25005222890000	OP	DEVON	KANE 32-15-31-18	84.912	70.1643	70.1643
25041225290000	OP	DEVON	KING 13-10-31-14	93.1935	77.8471	77.8471
25041211030000	OP	DEVON	KRAVIK 06-29 SE NW	96.875	85.1562	85.1562
25041229850000	OP	DEVON	KRAVIK 29-14-32-16	96.875	85.1563	85.1563
25005224230000	OBO	BROWN J BURNS OPERG CO	KREBS 22-32-18 NW SE SE	21.4328	19.0357	19.0357
25041221170000	OBO	BROWN J BURNS OPERG CO	KULBECK 03-32-15B	6.3119	4.8174	4.8174
25041213360000	OP	DEVON	LAMEY 01-21-32-15 NENE	97.5803	80.8897	80.8897
25005215960000	OP	DEVON	HOFELDT 07-13-30-19	83.5466	69.5783	69.5783
25041229800000	OP	DEVON	LEE 06-05-31-16	93.1935	77.8471	77.8471
25041235180000	OP	DEVON	LOTTON 11-09-31-14	93.1935	77.8471	77.8471
25005235060000	OP	DEVON	LOVELL 11-04-25-18	54.1696	47.2733	47.2733
25041210770000	OP	DEVON	LUMPKIN 23-01 NE SW	100	85.356	85.356
25005225420000	OBO	BROWN J BURNS OPERG CO	LUX 22-32-18 (AKA 22-13)	21.4328	19.0357	19.0357
25005235560000	OBO	NFR	LUX 24-05-32-18B	30.0412	25.3694	25.3694
25005225180000	OP	DEVON	LUX 27-01-32-18	71.4745	59.7056	59.7056
25041229890000	OP	DEVON	MAJERUS 01-06-31-15 (WO)	93.1935	77.8471	77.8471
25041227260000	OP	DEVON	MAJERUS 02-01-31-15	93.1935	77.8471	77.8471
25041223090000	OP	DEVON	MAJERUS 02-07-31-15	93.1935	77.8471	77.8471
25041234220000	OP	DEVON	MANUEL 12-15-31-15	91.6329	74.1164	74.1164
25041222820000	OP	DEVON	MANUEL 30-08-31-16	93.1935	77.8471	77.8471
25005224890000	OP	DEVON	MARSH 23-16-32-18	58.1762	48.4763	48.4763
25005225530000	OP	DEVON	MARSH 23-16B-32-18	50.8158	41.5734	41.5734
25005224850000	OP	DEVON	MARSH 35-03-32-18	72.6306	60.7057	60.7057
25005224880000	OP	DEVON	LUX 23-13-32-18	58.1762	48.4763	48.4763
25041222870000	OP	DEVON	MCINTOSH 08-16-31-15	93.1935	77.8471	77.8471
25005218530000	OP	DEVON	MCLEISH 01-20 (20-01-27-19)	88.4148	76.1811	76.1811
25005223980000	OP	DEVON	MCLEISH 10-17 (17-10-27-19)	100	86.0625	86.0625
25005234420000	OP	DEVON	MCLEISH 15-14-27-19	98.3008	85.7347	85.7347
25005220910000	OBO	BROWN J BURNS OPERG CO	MARSH 26-32-18 NE SW SW	31.7188	27.7539	27.7539
25015215100000	OP	DEVON	MCBRIDE 33-06-26-17	51.8029	41.5141	41.5141
25041224850000	OP	DEVON	NEUWERTH 18-14-31-15	93.1935	77.8471	77.8471
25005213080000	OP	DEVON	MOORE 33-14-27-18	75.0461	62.3654	62.3654
25005214520000	OP	DEVON	MOORE 74-21-27-18	78.8852	66.0015	66.0015
25005233610000	OP	DEVON	MOORE-DIR 01-13A-27-18	91.7224	78.7452	78.7452
25005233630000	OP	DEVON	MOORE-DIR 01-13C-27-18	91.7224	78.7452	78.7452
25041233080000	OP	DEVON	NEUWERTH 18-15-31-15	93.1935	77.8471	77.8471
25041233550000	OP	DEVON	NEUWERTH 18-16-31-15	93.1935	77.8471	77.8471
25041235230000	OP	DEVON	NEUWERTH 32-09-32-15	93.1935	77.8471	77.8471
25041235380000	OP	DEVON	NEUWERTH-DIR 17-09-31-15	93.1935	77.8471	77.8471
25015213230000	OP	DEVON	NORDEN 03-29 (29-04-27-17)	100	86.375	86.375
25041222450000	OP	DEVON	NYSTROM 14-05-30-15	93.1935	77.8471	77.8471
25005233550000	OP	DEVON	MOORE-DIR 12-04-27-18	86.6594	73.5945	73.5945
25005234660000	OP	DEVON	MOORE-DIR 14-15A-27-18	87.6123	70.0898	70.0898
25005236060000	OP	DEVON	MORGAN 33-12-25-18	55.3694	45.4649	45.4649
25005053100000	OP	DEVON	MORRISON 06-10-31-18	84.912	70.1643	70.1643
25005050290000	OP	DEVON	MPC FEE MILLER 08-16-31-19	100	93.25	93.25
25041220110000	OP	DEVON	NYSTROM 14-11-30-15	93.1935	77.8471	77.8471
25041221620000	OP	DEVON	NYSTROM 14-14-30-15	93.1935	77.8471	77.8471
25041222850000	OP	DEVON	NYSTROM 15-10-30-15	93.1935	77.8471	77.8471
25041215720000	OP	DEVON	NYSTROM 15-16X-30-15	93.1935	77.8471	77.8471
25041230830000	OP	DEVON	NYSTROM 22-02-30-15	93.1935	77.8471	77.8471
25005223830000	OP	DEVON	MIEWALD 23-04-32-18	58.1762	48.4763	48.4763
25005223930000	OP	DEVON	MONSON 20-09-31-18	84.912	70.1643	70.1643
25005224680000	OBO	BROWN J BURNS OPERG CO	MONTANA 25-32-18 SE NW NW	0.7812	0.6836	0.6836
25005222690000	OP	DEVON	MUELLER 07-16-31-19	85.2601	72.0906	72.0906
25005222700000	OP	DEVON	MUELLER 18-08-31-19	85.743	73.8252	73.8252
25041220410000	OP	DEVON	NYSTROM 22-08X-30-15	93.1935	77.8471	77.8471
25041226140000	OP	DEVON	NYSTROM 22-10-30-15 BHU	93.1935	77.8471	77.8471
25041229680000	OP	DEVON	NYSTROM 22-16-30-15	93.1935	77.8471	77.8471
25041230840000	OP	DEVON	NYSTROM 23-03-30-15	93.1935	77.8471	77.8471
25041223680000	OP	DEVON	NYSTROM 23-04-30-15	93.1935	77.8471	77.8471
25005224960000	OBO	BROWN J BURNS OPERG CO	MONTGOMERY 26-32-18 (SE NW NW)	31.7188	27.7539	27.7539

25005232270000	OP	DEVON	MOORE 01-13-27-18	94.485	81.4152	81.4152
25005233620000	OP	DEVON	MOORE 01-13B-27-18	91.7224	78.7452	78.7452
25005219780000	OP	DEVON	MOORE 06-24 (24-06-27-18)	100	85.3125	85.3125
25041224910000	OP	DEVON	NYSTROM 26-04-30-15	94.2731	78.2785	78.2785
25005229950000	OP	DEVON	MOORE 11-01-27-18	99.8523	85.8628	85.8628
25005228100000	OP	DEVON	MOORE 11-16-27-18	99.8523	85.8628	85.8628
25005232330000	OP	DEVON	MOORE 12-06-27-18	86.6594	73.5945	73.5945
25005229960000	OP	DEVON	MOORE 12-07-27-18	86.6594	73.5945	73.5945
25005228150000	OP	DEVON	MOORE 13-10-27-18	69.2875	56.9113	56.9113
25005228160000	OP	DEVON	MOORE 13-12-27-18	69.2875	56.9113	56.9113
25041220060000	OP	DEVON	NEUWERTH 04-13-31-15	93.1935	77.8471	77.8471
25041226770000	OP	DEVON	NEUWERTH 08-14-31-15	93.1935	77.8471	77.8471
25041225470000	OP	DEVON	NYSTROM 26-05-30-15	93.447	78.0917	78.0917
25041229840000	OP	DEVON	NYSTROM 27-01-30-15	93.1935	77.8471	77.8471
25041233790000	OP	DEVON	NYSTROM 35-01-30-15	94.2731	78.2785	78.2785
25041224920000	OP	DEVON	NYSTROM 35-02-30-15	94.2731	78.2785	78.2785
25041225700000	OP	DEVON	NYSTROM 35-06-30-15	94.2731	78.2785	78.2785
25041229700000	OP	DEVON	NYSTROM 35-07-30-15	94.2731	78.2785	78.2785
25041229690000	OP	DEVON	NYSTROM 35-2A-30-15	94.2731	78.2785	78.2785
25041231010000	OP	DEVON	NYSTROM-DIR 23-13-30-15	93.1935	77.8471	77.8471
25041233260000	OP	DEVON	NYSTROM-DIR 26-03-30-15	94.2731	78.2785	78.2785
25041233250000	OP	DEVON	NYSTROM-DIR 26-06-30-15	94.2731	78.2785	78.2785
25041231040000	OP	DEVON	NYSTROM-DIR 35-05-30-15	94.2731	78.2785	78.2785
25005231870000	OP	DEVON	MOORE 14-01-27-18	86.0427	73.103	73.103
25005228170000	OP	DEVON	MOORE 14-08-27-18	75.0461	62.3654	62.3654
25005226590000	OP	DEVON	MOORE 14-14-26-18	53.6439	43.9033	43.9033
25005230150000	OP	DEVON	MOORE 20-16-27-18	65.0688	52.9793	52.9793
25041225320000	OP	DEVON	NEUWERTH 17-01-31-15	93.1935	77.8471	77.8471
25041225300000	OP	DEVON	NEUWERTH 17-13-31-15	93.1935	77.8471	77.8471
25041227890000	OP	DEVON	NEUWERTH 18-05-31-15	93.1935	77.8471	77.8471
25041224330000	OP	DEVON	NEUWERTH 18-06-31-15	93.1935	77.8471	77.8471
25041211620000	OP	DEVON	NEUWERTH 18-10-31-15 BHU	93.1935	77.8471	77.8471
25005232890000	OP	DEVON	O CONNELL 11-09-25-18	53.6439	43.7532	43.7532
25005232500000	OP	DEVON	O CONNELL 34-03-26-19	53.6439	44.0227	44.0227
25005225740000	OP	DEVON	O CONNELL 34-15-26-19	53.6439	43.7782	43.7782
25005232070000	OP	DEVON	MOORE 21-06-27-18	79.0362	66.1307	66.1307
25005228210000	OP	DEVON	MOORE 21-09-27-18	78.8852	66.0015	66.0015
25005227830000	OP	DEVON	MOORE 23-03-26-18	53.6439	34.9585	34.9585
25005228220000	OP	DEVON	MOORE 28-11-27-18	86.5633	73.5106	73.5106
25005233860000	OP	DEVON	HOFELDT 07-15X-30-19	83.5466	69.5783	69.5783
25005232090000	OP	DEVON	HOFELDT 09-01-30-18	84.912	70.1643	70.1643
25005214550000	OP	DEVON	HOFELDT 09-02-30-18	84.912	70.1643	70.1643
25005236750000	OP	DEVON	HOFELDT 09-07-30-18	84.912	70.1643	70.1643
25005228660000	OP	DEVON	HOFELDT 09-08-30-18	84.912	70.1643	70.1643
25005227020000	OP	DEVON	HOFELDT 10-01-30-18	84.912	70.1643	70.1643
25005214030000	OP	DEVON	HOFELDT 10-02-30-18	84.912	70.1643	70.1643
25005237150000	OP	DEVON	HOFELDT 10-02A-30-18	84.912	70.1643	70.1643
25005236760000	OP	DEVON	HOFELDT 10-03-30-18	84.912	70.1643	70.1643
25005237160000	OP	DEVON	HOFELDT 10-03A-30-18	84.912	70.1643	70.1643
25005228520000	OP	DEVON	HOFELDT 10-08-30-18	84.912	70.1643	70.1643
25041222290000	OBO	SECTOR RESOURCES	HANSON 17-07 SW NE	36.25	28.1938	28.1938
25041232450000	OP	DEVON	HANSON 20-12-32-17	83.5466	69.5799	69.5799
25041230340000	OP	DEVON	HANSON 22-07-32-17	97.4512	85.1484	85.1484
25041233490000	OP	DEVON	HANSON-DIR 16-13-32-17	87.7079	74.2826	74.2826
25005226830000	OP	DEVON	HAYES 1-17 (17-01-31-19)	100	88.75	88.75
25005236150000	OP	DEVON	HAYES 17-15-31-19	100	83.9583	83.9583
25041211850000	OP	DEVON	HEGLE 01-07-30-15 BHU	93.1935	77.8471	77.8471
25041225370000	OP	DEVON	HEGLE 02-04-30-15	93.1935	77.8471	77.8471
25041232110000	OP	DEVON	HEGLE 03-13A-30-16	96.6722	82.8683	82.8683
25041229210000	OP	DEVON	HEGLE 22-01-31-15	93.1935	77.8471	77.8471
25005225080000	OP	DEVON	HOFELDT 11-04-30-18	84.912	70.1643	70.1643
25005210740000	OP	DEVON	HOFELDT 11-06-30-18	84.912	70.1643	70.1643
25005224740000	OP	DEVON	HOFELDT 12-16-30-18	84.912	70.1643	70.1643
25005227930000	OP	DEVON	HOFELDT 18-03-30-19 (TRU)	84.912	70.1643	70.1643
25005226540000	OP	DEVON	HOFELDT 18-04-30-19	84.912	70.1643	70.1643
25005237290000	OP	DEVON	HOFELDT-DIR 11-11-30-18 (EAGLE)	84.912	70.1643	70.1643
25015212640000	OP	DEVON	HOKANSON 02-35 (35-10-27-16)	100	86.4375	86.4375
25015212790000	OP	DEVON	HOKANSON 03-25 (25-08-27-16)	100	86.4375	86.4375
25015217020000	OP	DEVON	HOKANSON 30-12-27-17	100	86.3752	86.3752
25041226570000	OP	DEVON	HEGLE 22-04-31-15 BHU	93.1935	77.8471	77.8471
25041235440000	OP	DEVON	HEGLE 22-07-31-15	93.1935	77.8471	77.8471
25041229940000	OP	DEVON	HEGLE 23-09-31-15	93.1935	77.8471	77.8471
25041210530000	OP	DEVON	HEGLE 24-10-31-15	93.1935	77.8471	77.8471
25041221600000	OP	DEVON	HEGLE 24-10X-31-15	93.1935	77.8471	77.8471
25041229950000	OP	DEVON	HEGLE 24-11-31-15	93.1935	77.8471	77.8471
25041225910000	OP	DEVON	HEGLE 24-13-31-15	93.1935	77.8471	77.8471
25041231300000	OP	DEVON	HEGLE 24-15-31-15	93.1935	77.8471	77.8471
25041221610000	OP	DEVON	HEGLE 30-03-31-16	93.1935	77.8471	77.8471
25041227550000	OP	DEVON	HEGLE 35-16-31-15	93.1935	77.8471	77.8471
25041234600000	OP	DEVON	HEGLE-DIR 01-08-30-15	93.1935	77.8471	77.8471
25015217000000	OP	DEVON	HOKANSON 31-05-27-17	100	87.3259	87.3259

25015050260000	OP	DEVON	HUEBSCHWERLEN 01-17-25-17	47.9738	38.6701	38.6701
25015211420000	OP	DEVON	IX RANCH 01-28A (28-16-27-15)	100	84.5	84.5
25015211410000	OP	DEVON	IX RANCH 1-22 (22-15-27-15)	100	85.25	85.25
25015217540000	OP	DEVON	IX RANCH 22-15-27-15	100	85.25	85.25
25015216030000	OP	DEVON	IX RANCH 26-809-27-15	100	85.1875	85.1875
25015217550000	OP	DEVON	IX RANCH 27-04-27-15	100	85.625	85.625
25015215890000	OP	DEVON	IX RANCH A5-27 (27-05-27-15)	100	85.625	85.625
25015212300000	OP	DEVON	IX RANCH-B 04-26 (26-2-27-15	100	84.875	84.875
25015212830000	OP	DEVON	HENDERSON 03-19 (19-09-27-17)	100	86.125	86.125
25015212840000	OP	DEVON	HENDERSON 04-20 (20-13-27-17)	100	86.3125	86.3125
25005218540000	OP	DEVON	HENDERSON 05-27 (27-05-27-17)	100	86.5	86.5
25015213130000	OP	DEVON	HENDERSON 06-21 (21-06-27-17)	100	86.5	86.5
25015213910000	OP	DEVON	HENDERSON 07-21 (21-07-27-17)	100	86.375	86.375
25015214100000	OP	DEVON	HENDERSON 08-21 (21-08-27-16)	100	86.5	86.5
25015213930000	OP	DEVON	HENDERSON 08-30 (30-08-27-17)	100	86.3125	86.3125
25015213960000	OP	DEVON	HENDERSON 16-28 (28-09-27-17)	100	86.4437	86.4437
25015216860000	OP	DEVON	HENDERSON 19-12-27-17	100	86.125	86.125
25015217080000	OP	DEVON	HENDERSON 19-14-27-17	100	86.125	86.125
25015216840000	OP	DEVON	HENDERSON 20-02-27-17	100	86.3125	86.3125
25005220970000	OP	DEVON	JACOBSON 13-07-26-18	53.6439	43.9033	43.9033
25005226580000	OP	DEVON	JACOBSON 13-14-26-18	53.6439	43.9033	43.9033
25041218220000	OP	DEVON	JESS 25-01-32-14	93.1935	77.8471	77.8471
25041233030000	OP	DEVON	JOHNSON 26-16-32-14	93.1935	77.8471	77.8471
25015217160000	OP	DEVON	HENDERSON 21-02-27-17	100	86.375	86.375
25015217500000	OP	DEVON	HENDERSON 21-09-27-16	100	86.5	86.5
25015217360000	OP	DEVON	HENDERSON 21-16X-27-16	100	86.5	86.5
25015217370000	OP	DEVON	HENDERSON 22-04X-27-16	100	86.375	86.375
25005236600000	OP	DEVON	HENDERSON 27-04-27-17	100	86.5	86.5
25005236330000	OP	DEVON	HENDERSON 27-11A-27-17	75	64.8938	64.8938
25005232860000	OP	DEVON	HENDERSON 27-12-27-17	73.125	63.2531	63.2531
25015217380000	OP	DEVON	HENDERSON 28-08-27-17	100	86.4437	86.4437
25015217410000	OP	DEVON	HENDERSON 30-15-27-17	100	86.3125	86.3125
25005236340000	OP	DEVON	HENDERSON-DIR 27-03-27-17	100	86.5	86.5
25005224910000	OBO	BROWN J BURNS OPERG CO	HENKES 22-32-18 NW SE SE	21.4328	19.0357	19.0357
25041219580000	OBO	WESTERN NATURAL GAS INC	KAFKA 07-18 SE SW	50.801	42.6729	42.6729
25041214980000	OP	DEVON	KAFKA 30-02-32-15	93.1935	77.8471	77.8471
25041222460000	OP	DEVON	KAFKA 30-14-32-15	93.1935	77.8471	77.8471
25041233150000	OP	DEVON	KAFKA 32-08-32-14	97.4939	82.1822	82.1822
25041228210000	OP	DEVON	KAFKA 34-16X-32-14	94.9878	77.0269	77.0269
25005223610000	OP	DEVON	KANE 04-12-30-18	84.912	70.1643	70.1643
25005225070000	OP	DEVON	KANE 04-13-30-18	84.912	70.1643	70.1643
25005228470000	OP	DEVON	KANE 05-03-30-18	84.912	70.1643	70.1643
25005225570000	OP	DEVON	KANE 05-05-30-18	84.912	70.1643	70.1643
25005236840000	OP	DEVON	KANE 05-05A-30-18	84.912	70.1643	70.1643
25005230070000	OP	DEVON	HERDEGEN 33-10-28-19	90.625	78.2553	78.2553
25041225280000	OP	DEVON	HERRON 08-01-30-15	93.1935	77.8471	77.8471
25041218010000	OP	DEVON	HERRON 33-13-31-15	93.1935	77.8471	77.8471
25041222840000	OP	DEVON	HERRON 34-05-31-15	93.1935	77.8471	77.8471
25041224610000	OP	DEVON	HILLBRANT 03-06-30-15	93.1935	77.8471	77.8471
25041227220000	OP	DEVON	HILLBRANT 34-03-31-15	93.1935	77.8471	77.8471
25041214840000	OP	DEVON	HILLBRANT 34-06-31-15 BHU	93.1935	77.8471	77.8471
25041234450000	OP	DEVON	HILLBRANT 34-09-31-15	93.1935	77.8471	77.8471
25005220440000	OP	DEVON	HILLER 03-05-31-18	83.5466	69.5783	69.5783
25005224870000	OP	DEVON	HILLER 03-07-31-18	83.5466	69.5783	69.5783
25005232180000	OP	DEVON	KANE 05-07-30-18	84.912	70.1643	70.1643
25005222790000	OP	DEVON	KANE 05-08-30-18	84.912	70.1643	70.1643
25005236720000	OP	DEVON	KANE 05-15A-30-18	84.912	70.1643	70.1643
25005236730000	OP	DEVON	KANE 05-16-30-18	84.912	70.1643	70.1643
25005228490000	OP	DEVON	KANE 08-08-30-18	84.912	70.1643	70.1643
25005228500000	OP	DEVON	KANE 08-11-30-18	84.912	70.1643	70.1643
25005236740000	OP	DEVON	KANE 09-04-30-18	84.912	70.1643	70.1643
25005227670000	OP	DEVON	KANE 09-06-30-18 (TRU)	84.912	70.1643	70.1643
25015211540000	OP	DEVON	KANE 1-21X (21-10-27-16)	100	86.5	86.5
25005232580000	OP	DEVON	KANE 10-09-26-17	52.2219	44.1973	44.1973
25041210600000	OP	DEVON	ERHARD 27-06-32-15 BHU	93.1935	77.8471	77.8471
25041225200000	OP	DEVON	FABER 06-10-30-16	93.1935	77.8471	77.8471
25015211900000	OP	DEVON	FABER 2-30 (30-02-27-16)	100	86.5	86.5
25015217260000	OP	DEVON	FABER 25-10-27-15	100	86.5	86.5
25015217090000	OP	DEVON	FABER 25-14-27-15	100	86.5	86.5
25015217720000	OP	DEVON	FABER 25-15-27-15	100	86.5	86.5
25015212730000	OP	DEVON	DUMAS 1-32 (32-05-27-16)	100	86.3125	86.3125
25015217470000	OP	DEVON	FABER 30-04-27-16	100	86.5	86.5
25015216790000	OP	DEVON	FABER 30-10-27-16	100	86.5	86.5
25015213650000	OP	DEVON	FABER 5-30 (30-12-27-16)	100	86.5	86.5
25015213570000	OP	DEVON	FABER 6-25 (25-01-27-15)	100	86.5	86.5
25041218110000	OP	DEVON	FALK 03-01-31-14	94.9878	78.0636	78.0636
25041216800000	OP	DEVON	FALTRINO 10-20 NW SE	64.0625	53.8125	53.8125
25015217100000	OP	DEVON	FABER 25-16-27-15	100	86.5	86.5
25005223880000	OP	DEVON	FEDERAL 10-26-17	52.2219	44.1973	44.1973
25015210820000	OP	DEVON	FEDERAL 10-29-26-17	52.8469	43.0621	43.0621
25005221530000	OP	DEVON	FEDERAL 11-18 (18-11-31-19)	100	87.5	87.5

25005223510000	OP	DEVON	FEDERAL 14-25-18 (14-05-25-18)	53.6439	43.1762	0
25005223870000	OP	DEVON	FEDERAL 14-26-19	53.6439	39.6008	39.6008
25005223120000	OP	DEVON	FEDERAL 14-31 (31-14-28-19)	100	86.2171	86.2171
25005213630000	OP	DEVON	FEDERAL 14-6 (06-10-27-19)	68.9322	59.4697	59.4697
25005212350000	OP	DEVON	FEDERAL 01-05 (05-03-27-19)	69.6098	60.0836	60.0836
25005223500000	OP	DEVON	FEDERAL 19-26-19	53.6439	34.4325	34.4325
25005214150000	OP	DEVON	FEDERAL 22-31 (31-11-27-20)	100	86	86
25005223530000	OP	DEVON	FEDERAL 23-26-19	53.6439	44.1608	44.1608
25005212740000	OP	DEVON	FEDERAL 01-15 (15-08-27-18)	92.3219	78.8896	78.8896
25005213940000	OP	DEVON	FEDERAL 10-12 (12-12-27-18)	86.5633	73.5104	73.5104
25005223780000	OP	DEVON	FEE 13-8 (08-13-31-19)	100	93.25	93.25
25005213640000	OP	DEVON	FEDERAL 15-07-27-19	92.5931	79.045	79.045
25041223860000	OP	DEVON	FELTON 19-01-31-15	93.1935	77.8471	77.8471
25041223160000	OP	DEVON	FELTON 19-02-31-15	93.1935	77.8471	77.8471
25041215780000	OP	DEVON	FELTON 19-11-31-15	93.1935	77.8471	77.8471
25005224860000	OP	DEVON	FINCH 02-03-31-18	83.5466	69.5783	69.5783
25005227250000	OP	DEVON	FINCH 34-08-32-18	73.0194	66.7461	66.7461
25005216700000	OP	DEVON	FEDERAL 29-28 (28-03-27-18)	86.5633	73.5106	73.5106
25005221630000	OP	DEVON	FINCH 35-01-32-18	72.6306	60.7057	60.7057
25005226030000	OP	DEVON	FINCH 35-11-32-18	72.6306	60.7057	60.7057
25005215310000	OP	DEVON	FINCH 35-16-32-18	72.6306	60.7057	60.7057
25005225860000	OP	DEVON	FEE 2-15 (15-02-31-19)	100	100	100
25005226040000	OP	DEVON	FINCH 34-16-32-18	73.0194	61.2395	61.2395
25005228140000	OP	DEVON	G READ 01-11-27-18	91.6986	78.8715	78.8715
25005230170000	OP	DEVON	G READ 06-13-27-19	68.9322	59.4697	59.4697
25005229530000	OP	DEVON	G READ 11-06-27-18	99.8523	85.8628	85.8628
25005229380000	OP	DEVON	G REED 11-13-27-18	99.8523	85.8628	85.8628
25005232970000	OBO	NFR BEAR PAW BASIN, LLC	GASVODA FEDERAL 12-25-18D (2003 OBO D&C - P4)	54.4094	45.4787	45.4787
25005232710000	OBO	NFR BEAR PAW BASIN, LLC	GASVODA FEDERAL 12-25-18E	54.4094	45.4787	45.4787
25041223640000	OP	DEVON	GOLIE 09-04-30-15	93.1935	77.8471	77.8471
25041224800000	OBO	BROWN J BURNS OPERG CO	GOLIE 24-01 NE NE	30	25	25
25041233310000	OBO	KOG	GOLIE FEDERAL 24-08-30-15B	30	25	25
25041212220000	OP	DEVON	GOVERNMENT 05-10-30-15	93.1935	77.8471	77.8471
25041215790000	OP	DEVON	GOVERNMENT 06-06X-30-16	93.1935	77.8471	77.8471
25005051070000	OP	DEVON	GOVT 1 (33-16-32-19)	100	87.5	87.5
25005232230000	OP	DEVON	GOWEN 28-02-31-19	89.7008	76.0648	76.0648
25005232630000	OP	DEVON	GOWEN 28-07-31-19	89.7008	76.0648	76.0648
25041225980000	OP	DEVON	GREENEICH 27-12-32-14	92.0194	76.3399	76.3399
25041233530000	OP	DEVON	GREENWAY 19-03-31-15	93.1935	77.8471	77.8471
25041230300000	OP	DEVON	GREGOIRE 13-06A-31-15	93.1935	77.8471	77.8471
25041229080000	OP	DEVON	FRAKES 26-04-32-15	100	87.5	87.5
25041228890000	OP	DEVON	FRAKES 26-06-32-15	100	87.5	87.5
25041235370000	OP	DEVON	FREDRICKSON-DIR 21-03-31-15	93.1935	77.8471	77.8471
25041224290000	OP	DEVON	GREGOIRE 19-11-31-16	93.1935	77.8471	77.8471
25005226850000	OP	DEVON	GUERTZGEN 11-35 (35-11-32-19)	100	87.5	87.5
25005216100000	OP	DEVON	GUERTZGEN 14-35 (34-14-32-19)	100	87.5	87.5
25041229540000	OP	DEVON	GUSSENHOVEN 03-04-31-17	84.912	70.1643	70.1643
25041226910000	OP	DEVON	HAGLUND 12-16X-31-14	93.1935	77.8471	77.8471
25041215350000	OP	DEVON	DAVEY 20-16-32-17	83.5466	69.5799	69.5799
25041231390000	OP	DEVON	DAVEY 23-05-32-17	100	87.5	87.5
25041215120000	OP	DEVON	DAVEY 26-16-32-17	84.912	70.1643	70.1643
25041217530000	OP	DEVON	DAVEY 27-05-32-17	83.5466	69.6025	69.6025
25041224170000	OP	DEVON	DAVEY 27-07-32-17	83.5466	69.6025	69.6025
25041212290000	OP	DEVON	DAVEY 28-06-32-17	83.5466	69.6049	69.6049
25041233760000	OP	DEVON	DAVEY 29-13-32-17	40.8519	33.3661	33.3661
25041233590000	OP	DEVON	DAVEY 32-13-32-17	73.3373	62.3781	62.3781
25041223890000	OP	DEVON	DAVEY 35-06-32-17	84.912	70.1643	70.1643
25005237770000	OP	DEVON	DAVEY-DIR 06-12-31-18	84.912	70.1643	70.1643
25005222880000	OP	DEVON	DAVIES RANCH 17-05-30-18 (JR)	84.912	70.1643	70.1643
25015213120000	OP	DEVON	DUMAS 2-31 (31-7-27-16)	93.6762	80.761	80.761
25005232260000	OP	DEVON	DUNBAR 04-07-27-19	73.0552	64.0845	64.0845
25005235860000	OP	DEVON	DUNBAR 05-04-27-19	69.2711	55.4169	55.4169
25005235920000	OP	DEVON	DUNBAR 06-01-27-19	68.9322	59.4697	59.4697
25005234230000	OP	DEVON	DUNBAR 06-07-27-19	68.9322	59.4697	59.4697
25005228360000	OP	DEVON	DUNBAR 06-08-27-19	68.9322	59.4693	59.4693
25005224010000	OP	DEVON	DUNBAR 1-6 (06-01-27-19)	68.9322	59.4697	59.4697
25005214260000	OP	DEVON	DUNBAR 2-4 (04-02-27-19)	73.0552	64.0845	64.0845
25005236700000	OP	DEVON	DEHLBOM 03-01-30-18	84.912	70.1643	70.1643
25005219440000	OP	DEVON	DEHLBOM 03-03-30-18	84.912	70.1643	70.1643
25005210200000	OP	DEVON	DEHLBOM 03-11-30-18	84.912	70.1643	70.1643
25005221620000	OP	DEVON	DEHLBOM 04-01-30-18	84.912	70.1643	70.1643
25005227950000	OP	DEVON	DEHLBOM 04-16-30-18 (TRU)	84.912	70.1643	70.1643
25005211470000	OP	DEVON	DEHLBOM 31-07-31-18	84.912	70.1643	70.1643
25005232470000	OP	DEVON	DEHLBOM 31-07B-31-18	84.912	70.1643	70.1643
25005229510000	OP	DEVON	DEHLBOM 31-08-31-18	84.912	70.1643	70.1643
25005214740000	OP	DEVON	DEHLBOM 31-15-31-18	84.912	70.1643	70.1643
25005232130000	OP	DEVON	DEHLBOM 31-7A-31-18	84.912	70.1643	70.1643
25005237120000	OP	DEVON	DEHLBOM 32-07-31-18	84.912	70.1643	70.1643
25005227540000	OP	DEVON	DEHLBOM 32-10-31-18 (TRU)	84.912	70.1643	70.1643
25005236860000	OP	DEVON	DEHLBOM 32-13-31-18	84.912	70.1643	70.1643

25005237130000	OP	DEVON	DEHLBOM 32-14-31-18 (EAGLE)	84.912	70.1643	70.1643
25005232200000	OP	DEVON	DEHLBOM 33-16-31-18	84.912	70.1643	70.1643
25005232160000	OP	DEVON	DEHLBOM 34-14-31-18	84.912	70.1643	70.1643
25005228670000	OP	DEVON	DEHLBOM 34-7-31-18	84.912	70.1643	70.1643
25005210140000	OP	DEVON	DEHLBOM 5-6-30-18	84.912	70.1643	70.1643
25005237280000	OP	DEVON	DEHLBOM-DIR 32-14A-31-18	84.912	70.1643	70.1643
25041212100000	OBO	WESTERN NATURAL GAS INC	DELANEY 10-01	24	19.7231	19.7231
25041223130000	OP	DEVON	ERHARD 07-16-31-15	93.1935	77.8471	77.8471
25041235400000	OP	DEVON	ERHARD 26-13-32-15	100	84.6536	84.6536
25005217050000	OP	DEVON	DICKEY 12-25 (25-12-32-19)	100	87.5	87.5
25005051410000	OP	DEVON	DICKEY 2 (35-04-32-19)	100	87.5	87.5
25041229550000	OP	DEVON	DION 25-16-32-16	93.5077	78.2949	78.2949
25041222120000	OBO	SECTOR RESOURCES	DION 30-12 NW SW	18.125	12.4544	12.4544
25041233770000	OP	DEVON	DION-DIR 31-06-32-17	96.25	81.7532	81.7532
25041225050000	OBO	BROWN J BURNS OPERG CO	DOW 19-32-17B	19.1966	15.6923	15.6923
25005214700000	OP	DEVON	SPRINKLE 02-04-30-18	84.912	70.1643	70.1643
25005226610000	OP	DEVON	SPRINKLE 14-09 (09-14-31-19)	100	87.5	87.5
25005226600000	OP	DEVON	SPRINKLE 16-09 (09-16-31-19)	100	87.4997	87.4997
25005211620000	OP	DEVON	STAFF 05-10-31-18	84.912	70.1643	70.1643
25005225560000	OP	DEVON	STAFF 31-16-32-18	84.912	70.1643	70.1643
25005224250000	OP	DEVON	STAFF 32-16-32-18	84.912	70.1643	70.1643
25005237800000	OP	DEVON	STAFF-DIR 32-05A-32-18	84.912	70.1643	70.1643
25041222340000	OP	DEVON	STATE 01-36-32-16	100	87.5	87.5
25015214900000	OP	DEVON	STATE 03-16 (16-03-28-14)	100	87.5	87.5
25005226630000	OP	DEVON	STATE 03-16 (16-03-31-19)	100	87.5	87.5
25005212860000	OP	DEVON	STATE 03-16 (16-09-27-20)	100	86.5	86.5
25041222300000	OBO	BROWN J BURNS OPERG CO	STATE 04-32-15 SW NE	26.0781	21.9056	21.9056
25041226120000	OP	DEVON	STATE 05-15-30-15 BHU	93.1935	77.8471	77.8471
25005218770000	OP	DEVON	STATE 05-16-26-19	53.6439	43.7532	43.7532
25015216460000	OP	DEVON	STATE 05-20 (20-05-27-14)	100	87.5	87.5
25041233090000	OP	DEVON	STATE 06-07-30-15	93.1935	77.8471	77.8471
25015216130000	OP	DEVON	STATE 06-16 (16-06-28-14)	100	87.5	87.5
25005226370000	OP	DEVON	STATE 08-16 (16-08-31-19)	100	87.5	87.5
25041221910000	OP	DEVON	STATE 13-16 SW SW	100	84	84
25005228390000	OP	DEVON	STATE 13-16-27-19	98.9805	86.5228	86.5228
25005214630000	OP	DEVON	STATE 13-36 (36-10-27-17)	100	86.5	86.5
25005221260000	OP	DEVON	STATE 14-36 (36-14-32-18)	100	87.5	87.5
25005226380000	OP	DEVON	STATE 15-16 (16-15-31-19)	100	87.5	87.5
25015218170000	OP	DEVON	STATE 16-05-27-17	100	86.5	86.5
25005235620000	OP	DEVON	STATE 16-07-25-18	55.0128	47.299	47.299
25041226780000	OP	DEVON	STATE 16-07-31-15	93.1935	77.8471	77.8471
25041221190000	OP	DEVON	STATE 16-10-32-17	83.5466	69.7533	69.7533
25041215090000	OP	DEVON	STATE 16-11-31-17	84.912	70.1643	70.1643
25005211870000	OP	DEVON	STATE 16-11A-31-18	84.912	70.1643	70.1643
25005229190000	OP	DEVON	STATE 16-12-27-19	100	86.5	86.5
25015213300000	OP	DEVON	STATE 16-36 (36-09-27-16)	100	86.5	86.5
25015212080000	OP	DEVON	STATE 17-30 (30-06-27-17)	100	86.3752	86.3752
25005217010000	OP	DEVON	STATE 09-16 (16-09-31-19)	100	87.5	87.5
25015217820000	OP	DEVON	STATE 19-02-27-14	100	83.5	83.5
25015216170000	OP	DEVON	STATE 1X RANCH 02-15-27-14	100	87.5	87.5
25015215800000	OP	DEVON	STATE 1X RANCH 1 (16-27-14)	100	87.5	87.5
25015218160000	OP	DEVON	STATE 20-03-27-14	100	87.5	87.5
25041210420000	OP	DEVON	STATE 20-11-31-16 BHU	93.1935	77.8471	77.8471
25041234240000	OP	DEVON	STATE 20-15-31-16	91.6329	74.1164	74.1164
25005236590000	OP	DEVON	STATE 21-09-27-19	100	79.879	79.879
25005236430000	OP	DEVON	STATE 21-16-27-19	100	86.5	86.5
25005234670000	OP	DEVON	STATE 22-12-27-19	100	85.7188	85.7188
25041229820000	OP	DEVON	STATE 22-13-32-15	98.745	81.467	81.467
25015213430000	OP	DEVON	STATE 18-16 (16-12-27-17)	100	86.5	86.5
25015211250000	OP	DEVON	STATE 24-16-25-17	47.7514	37.9562	37.9562
25015212350000	OP	DEVON	STATE 24-36 (36-04-27-16)	100	86.5	86.5
25041222890000	OP	DEVON	STATE 28-08-32-15	93.1935	77.8471	77.8471
25041218420000	OP	DEVON	STATE 29-01-32-15	93.1935	77.8471	77.8471
25005213480000	OP	DEVON	STATE 21X-21 (NW)	86.81	65.6809	65.6809
25041234250000	OP	DEVON	STATE 29-03-31-16	91.6329	74.1164	74.1164
25005225580000	OP	DEVON	STATE 36-01-31-17	84.912	70.1643	70.1643
25015217040000	OP	DEVON	STATE 36-02-27-16	100	86.5	86.5
25005237220000	OP	DEVON	STATE 36-02-31-17	84.912	70.1643	70.1643
25005236010000	OP	DEVON	STATE 36-05-31-17	84.912	70.1643	70.1643
25041232940000	OP	DEVON	STATE 36-05-32-14	93.1935	77.8471	77.8471
25041229720000	OP	DEVON	STATE 36-06-30-15	93.5235	81.8331	81.8331
25015212320000	OP	DEVON	STATE 22-31 (31-10-27-15)	100	87.5	87.5
25005219430000	OP	DEVON	STATE 36-09-31-17	84.912	70.1643	70.1643
25041226010000	OP	DEVON	STATE 29-02X-31-16	93.1935	77.8471	77.8471
25041235170000	OP	DEVON	STATE 36-10A-32-14	93.1935	77.8471	77.8471
25041226420000	OP	DEVON	STATE 36-11-30-15	93.5235	81.8331	81.8331
25005211860000	OP	DEVON	STATE 36-11-31-17	84.912	70.1643	70.1643
25015217520000	OP	DEVON	STATE 36-12-27-16	100	86.5	86.5
25005235690000	OP	DEVON	STATE 36-12-31-17	84.912	70.1643	70.1643
25041227990000	OP	DEVON	STATE 36-13-31-14	93.1935	77.8471	77.8471
25041229840000	OP	DEVON	STATE 36-13-32-15	97.1362	83.332	83.332

25015217530000	OP	DEVON	STATE 36-14-27-16	100	86.5	86.5
25041051760000	OP	DEVON	STATE 36-06-32-17	84.912	70.1643	70.1643
25005227150000	OP	DEVON	STATE 36-10-32-17	84.912	70.1643	70.1643
25005226710000	OP	DEVON	STATE 36-15-32-17	84.912	70.1643	70.1643
25005232800000	OP	DEVON	STEVENS 14-07-25-18	53.6439	44.2494	44.2494
25005232810000	OP	DEVON	STEVENS 14-16A-25-18	50.4408	42.0452	42.0452
25005231880000	OP	DEVON	STATE 36-14-27-17	100	86.5	86.5
25005224270000	OP	DEVON	STATE 36-16-32-17	84.912	70.1643	70.1643
25041224730000	OP	DEVON	STIRLING 19-02-30-16	76.5987	64.7959	64.7959
25041230040000	OP	DEVON	STIRLING 19-16-30-16	76.5987	64.5038	64.5038
25041230850000	OP	DEVON	STIRLING 20-13-30-16	95.3069	81.1118	81.1118
25041230800000	OP	DEVON	STIRLING-DIR 19-01-30-16	76.5987	64.7959	64.7959
25041230470000	OP	DEVON	STIRLING-DIR 19-08-30-16	76.5987	64.7959	64.7959
25041230810000	OP	DEVON	STIRLING-DIR 30-01-30-16	95.3069	82.9408	82.9408
25041229980000	OP	DEVON	SUNDAY 03-8-31-15	93.1935	77.8471	77.8471
25041212070000	OBO	WESTERN NATURAL GAS INC	SWICK 23-07-32-14	9.783	7.9839	7.9839
25041224600000	OP	DEVON	TAUTGES 29-08-31-16	93.1935	77.8471	77.8471
25005226100000	OP	DEVON	THIES 14-08-26-18	53.6439	43.9033	43.9033
25041222110000	OBO	SECTOR RESOURCES	TURNER 04-31	18.125	12.4544	12.4544
25005229520000	OP	DEVON	TVEDTE 32-13-32-18	84.912	70.1643	70.1643
25005226720000	OP	DEVON	TVEDTE 32-14-32-18	84.912	70.1643	70.1643
25041234510000	OP	DEVON	STATE-DIR 06-03-30-15	93.1935	77.8471	77.8471
25005235630000	OP	DEVON	STATE-DIR 16-09-25-18	87.0867	71.3101	71.3101
25005236580000	OP	DEVON	STATE-DIR 16-09-27-19	100	86.5	86.5
25015218190000	OP	DEVON	STATE-DIR 16-14-27-17	100	86.5	86.5
25041235420000	OP	DEVON	STATE-DIR 16-15-31-15	93.1935	77.8471	77.8471
25005237260000	OP	DEVON	STATE-DIR 23-15-27-19	100	87.5	87.5
25005236610000	OP	DEVON	STATE-DIR 25-16-27-19	100	86.4409	86.4409
25005237320000	OP	DEVON	STATE-DIR 27-04-27-19	100	71.304	71.304
25041231370000	OP	DEVON	STATE-DIR 36-01A-32-16	100	87.5	87.5
25041233780000	OP	DEVON	STATE-DIR 36-02-30-15	93.5235	81.8331	81.8331
25041233730000	OP	DEVON	STATE-DIR 36-03-30-15	93.5235	81.8331	81.8331
25041233750000	OP	DEVON	STATE-DIR 36-05-30-15	93.5235	81.8331	81.8331
25041233740000	OP	DEVON	STATE-DIR 36-4A-30-15	93.5235	81.8331	81.8331
25041223170000	OP	DEVON	STERRETT 29-13-32-15	93.1935	77.8471	77.8471
25005235100000	OP	DEVON	STEVENS 09-01-25-18	55.5135	45.7329	45.7329
25015214910000	OP	DEVON	TRUNK 14-9 (09-14-28-14)	100	87.5	87.5
25015214890000	OP	DEVON	TRUNK 16-8 (08-16-28-14)	100	87.2394	87.2394
25041235210000	OP	DEVON	SIEBRASSE 07-04-31-15	93.1935	77.8471	77.8471
25041211990000	OP	DEVON	SIMMONS 14-07-30-15 BHU	93.1935	77.8471	77.8471
25005224770000	OP	DEVON	SIVERTSEN 13-03-26-18	53.6439	43.9033	43.9033
25041211460000	OP	DEVON	SJOVOLD 26-02-32-14 BHU	93.1935	77.8471	77.8471
25015214200000	OP	DEVON	SLEMAKER 16-05-26-17	35.8959	40	40
25041224160000	OP	DEVON	SOLOMON 19-12-31-17	83.5466	69.5783	69.5783
25041228470000	OP	DEVON	SOLOMON 19-14-31-17	83.5466	69.5783	69.5783
25041214320000	OP	DEVON	SOLOMON 19-15-31-17	83.5466	69.5783	69.5783
25041219830000	OP	DEVON	SOLOMON 27-10-31-16	93.5077	78.2949	78.2949
25041229560000	OP	DEVON	SOLOMON 34-06-32-16	90.3471	75.7716	75.7716
25005217790000	OP	DEVON	SORENSEN 07-14-31-19	87.2548	72.2779	72.2779
25015213780000	OP	DEVON	STATE 12-19 (19-12-27-14)	100	83.5	83.5
25005222710000	OP	DEVON	SORENSEN 12-15-31-18	83.5466	69.0035	69.0035
25005218450000	OP	DEVON	SORENSEN 13-07-31-18	83.5466	68.9506	68.9506
25005220450000	OP	DEVON	SORENSEN 18-06-31-19	85.743	71.5002	71.5002
25005231150000	OBO	BROWN J BURNS OPERG CO	SPENCE 22-32-18D	25.1981	18.7537	18.7537
25005229490000	OP	DEVON	SPENCER 17-13-31-18	84.912	70.1643	70.1643
25005214100000	OP	DEVON	SPENCER 20-02-31-18	84.912	70.1643	70.1643
25005226620000	OP	DEVON	STATE 01-16 (16-01-31-19)	100	87.5	87.5
25005212370000	OP	DEVON	STATE 01-16 (16-06-27-19)	100	86.5	86.5
25015214480000	OP	DEVON	STATE 01-33 (33-01-27-15)	100	87.5	87.5
25005215100000	OP	DEVON	STATE 01-36 (36-01-32-18)	100	87.5	87.5
25005210060000	OP	DEVON	RAMBERG 13-10-31-17	84.912	70.1643	70.1643
25005223220000	OP	DEVON	RAMBERG 19-05-31-18	84.912	70.1643	70.1643
25005214240000	OP	DEVON	RAMBERG 22-13-31-18	84.912	70.1643	70.1643
25005226560000	OP	DEVON	RAMBERG 24-16-31-17	84.912	70.1643	70.1643
25005211790000	OP	DEVON	RAMBERG 28-06-31-18	84.912	70.1643	70.1643
25005223630000	OP	DEVON	RAMBERG 29-13-31-18	84.912	70.1643	70.1643
25005233820000	OP	DEVON	READ 01-06-27-18	91.7224	78.7452	78.7452
25005233080000	OP	DEVON	READ 01-07A-27-18	91.778	78.7882	78.7882
25005234220000	OP	DEVON	READ 12-01-27-18	86.6594	73.5945	73.5945
25005233720000	OP	DEVON	READ-DIR 06-14-27-19	68.9322	59.4697	59.4697
25005233280000	OBO	NFR	REEVES 07-11-25-19B 2004 OBO	60.0626	52.1754	52.1754
25005234830000	OBO	KOGI	REEVES 10-12-25-18	54.6741	45.9837	45.9837
25005231060000/0001	OBO	NFR BEAR PAW BASIN, LLC	REEVES 12-25-18B	54.4094	45.4787	45.4787
25005231970000	OBO	NFR BEAR PAW BASIN, LLC	REEVES FEDERAL 12-25-18C	58.0368	45.4787	45.4787
25041231230000	OP	DEVON	REUM 29-04-30-16	95.713	83.7488	83.7488
25041225680000	OP	DEVON	RICHARDSON 27-10-32-14	92.0194	76.3399	76.3399
25005227690000	OP	DEVON	RISLEY 11-06B-31-18	83.5466	69.5212	69.5212
25005236420000	OP	DEVON	RISLEY 11-12-31-18	83.5466	69.5212	69.5212
25005233480000	OP	DEVON	READ-DIR 11-14-27-18	99.8523	85.8628	85.8628
25005223940000	OP	DEVON	ROBERTS 23-03-31-18	84.9096	70.4184	70.4184
25005225600000	OP	DEVON	ROBERTS 26-12-31-18	84.912	70.1643	70.1643

25005210120000	OP	DEVON	ROBERTS 27-10-31-18	84.912	70.1643	70.1643
25005215970000	OP	DEVON	ROBERTS 28-04-31-19	89.7008	74.4517	74.4517
25005225680000	OP	DEVON	ROBERTS 28-16-31-19	89.7008	74.4517	74.4517
25005220470000	OP	DEVON	ROBERTS 33-06-31-19	83.5466	69.3437	69.3437
25005225250000	OP	DEVON	ROBERTS 33-16-31-19	84.7288	70.0566	70.0566
25005212560000	OP	DEVON	ROBINSON 11-34C-26-19	53.6439	43.8032	43.8032
25005224640000	OP	DEVON	ROBINSON 34-05-26-19	53.6439	43.7782	43.7782
25005235910000	OBO	KOG	ROBINSON FEDERAL 03-12-25-18	54.4094	44.7537	44.7537
25005227860000	OBO	KOGI	ROBINSON FEDERAL 03-25-18	54.4094	44.7537	44.7537
25041213520000	OP	DEVON	ROCKY BOY 01-10-29-15	100	86.5	86.5
25041213840000	OP	DEVON	ROCKY BOY 01-15-29-15	100	86.5	86.5
25041229010000	OP	DEVON	ROCKY BOY 05-05-30-15	93.1935	77.8471	77.8471
25041229020000	OP	DEVON	ROCKY BOY 05-06-30-15	93.1935	77.8471	77.8471
25041225840000	OP	DEVON	ROCKY BOY 05-12-30-15	93.1935	77.8471	77.8471
25041227650000	OP	DEVON	ROCKY BOY 06-05-30-16	93.1935	77.8471	77.8471
25005217800000	OP	DEVON	ROBERTS 15-14-31-19	87.2548	72.2779	72.2779
25041229180000	OP	DEVON	ROCKY BOY 09-08-29-15	100	78.75	78.75
25041231970000	OP	DEVON	ROCKY BOY 09-15-29-15	100	78.75	78.75
25041232810000	OP	DEVON	ROCKY BOY 10-10-29-15	100	86.5	86.5
25041229770000	OP	DEVON	ROCKY BOY 10-15-29-15	100	86.5	86.5
DUAL25005212560000	OP	DEVON	ROBINSON 11-34T-26-19	53.6439	43.7782	43.7782
25015214690000	OBO	KOGI	ROCKY BOY 11-29-14	19.15	16.7562	16.7562
25041229640000	OP	DEVON	ROCKY BOY 15-02-29-15	100	86.5	86.5
25041229650000	OP	DEVON	ROCKY BOY 15-07-29-15	100	86.5	86.5
25041232820000	OP	DEVON	ROCKY BOY 17-06-29-15	100	78.75	78.75
25041231990000	OP	DEVON	ROCKY BOY 17-12-29-15	100	78.75	78.75
25041232000000	OP	DEVON	ROCKY BOY 18-05-29-15	100	78.75	78.75
25041228180000	OP	DEVON	ROCKY BOY 06-11-30-16	93.1935	77.8471	77.8471
25041229670000	OP	DEVON	ROCKY BOY 18-12-29-15	100	78.75	78.75
25041229480000	OP	DEVON	ROCKY BOY 19-09-30-15	100	86.5	86.5
25041226640000	OP	DEVON	ROCKY BOY 19-15-30-15	100	86.5	86.5
25041225650000	OP	DEVON	ROCKY BOY 19-16-30-15	100	86.5	86.5
25041216210000	OP	DEVON	ROCKY BOY 07-19-30-15	100	86.5	86.5
25041225800000	OP	DEVON	ROCKY BOY 20-10-30-15	93.1935	77.8471	77.8471
25041226200000	OP	DEVON	ROCKY BOY 20-11-30-15 BHU	93.1935	77.8471	77.8471
25041225950000	OP	DEVON	ROCKY BOY 20-13-30-15	93.1935	77.8471	77.8471
25041226670000	OP	DEVON	ROCKY BOY 20-14-30-15	93.1935	77.8471	77.8471
25041226680000	OP	DEVON	ROCKY BOY 20-15-30-15	93.1935	77.8471	77.8471
25041232010000	OP	DEVON	ROCKY BOY 18-09-29-15	100	78.75	78.75
25041229030000	OP	DEVON	ROCKY BOY 20-16B-30-15	93.1935	77.8471	77.8471
25041225810000	OP	DEVON	ROCKY BOY 21-05-30-15	93.1935	77.8471	77.8471
25041225820000	OP	DEVON	ROCKY BOY 21-12-30-15	93.1935	77.8471	77.8471
25041226330000	OP	DEVON	ROCKY BOY 21-13-30-15 BHU	93.1935	77.8471	77.8471
25041225830000	OP	DEVON	ROCKY BOY 22-04B-30-15	93.1935	77.8471	77.8471
25041224300000	OP	DEVON	ROCKY BOY 22-12-30-15 BHU	93.1935	77.8471	77.8471
25041228040000	OP	DEVON	ROCKY BOY 25-15-30-14	100	80	80
25041227950000	OP	DEVON	ROCKY BOY 29-03-30-15	100	80	80
25041229040000	OP	DEVON	ROCKY BOY 29-04A-30-15	100	80	80
25041227530000	OP	DEVON	ROCKY BOY 20-01-30-15 (2)	93.1935	77.8471	77.8471
25041228870000	OP	DEVON	ROCKY BOY 29-08-30-15	100	80	80
25041229450000	OP	DEVON	ROCKY BOY 29-09-30-15	100	80	80
25041229050000	OP	DEVON	ROCKY BOY 30-01B-30-15	100	80	80
25041226850000	OP	DEVON	ROCKY BOY 30-11-30-15	100	80	80
25041226440000	OP	DEVON	ROCKY BOY 35-11-30-15	100	80	80
25041226690000	OP	DEVON	ROCKY BOY 20-16-30-15	93.1935	77.8471	77.8471
25005215140000	OP	DEVON	SHEPARD 10-34 (34-10-32-19)	100	87.5	87.5
25041226700000	OP	DEVON	ROCKY BOY 29-07-30-15	100	80	80
25041232080000	OP	DEVON	ROCKY BOY-DIR 09-10-29-15	100	78.75	78.75
25041233340000	OP	DEVON	ROCKY BOY-DIR 23-07-30-15	93.1935	77.8471	77.8471
25041233350000	OP	DEVON	ROCKY BOY-DIR 23-08-30-15	93.1935	77.8471	77.8471
25041232030000	OP	DEVON	ROCKY BOY-DIR 24-09-30-15	60	50	50
25041232750000	OP	DEVON	ROCKY BOY-DIR 24-16-30-15	60	50	50
25005227710000	OP	DEVON	S B RANCH 28-12-31-19	89.7008	74.4517	74.4517
25005227720000	OP	DEVON	S B RANCH 33-02-31-19	83.5466	69.3437	69.3437
25005225700000	OP	DEVON	S B RANCH 34-04-31-19	85.2601	70.7659	70.7659
25005212100000	OP	DEVON	S B RANCH 34-06-31-18	84.912	70.1643	70.1643
25005227730000	OP	DEVON	S B RANCH 34-12-31-19	84.4055	70.0798	70.0798
25041228090000	OP	DEVON	ROCKY BOY 35-16-31-14	97.4939	80.9322	80.9322
25005050490000	OP	DEVON	SIAS 1 (04-14-31-19)	100	98	98
25005216720000	OP	DEVON	SIAS 11-15 (15-11-31-19)	100	100	100
25005225050000	OP	DEVON	SIAS 3-15 (15-03-31-19)	100	100	100
25005216780000	OP	DEVON	SIAS 7-15 (15-07-31-19)	100	100	100
25005210860000	OP	DEVON	ROSS 01-07-30-17	84.912	70.1643	70.1643
25005227590000	OP	DEVON	ROSS 01-12-30-17 (TRU)	84.912	70.1643	70.1643
25005219450000	OP	DEVON	ROSS 01-15-30-17	84.912	70.1643	70.1643
25005229470000	OP	DEVON	ROSS 02-02-30-17	84.912	70.1643	70.1643
25005230830000	OP	DEVON	ROSS 02-05-30-17	84.912	70.1643	70.1643
25005227600000	OP	DEVON	ROSS 02-07-30-17 (TRU)	84.912	70.1643	70.1643
25005229550000	OP	DEVON	S-B RANCH 02-05-30-18	84.912	70.1643	70.1643
25005236160000	OP	DEVON	S-B RANCH 25-04-31-19	87.7992	73.9033	73.9033
25005229560000	OP	DEVON	S-B RANCH 26-10-31-18	84.912	70.1643	70.1643

25005213990000	OP	DEVON	ROSS 02-09-30-17	84.912	70.1643	70.1643
25005214310000	OP	DEVON	ROSS 03-01-30-17	84.912	70.1643	70.1643
25005226010000	OP	DEVON	ROSS 06-05-30-18	84.912	70.1643	70.1643
25005214710000	OP	DEVON	ROSS 07-10-30-18	84.912	70.1643	70.1643
25005227910000	OP	DEVON	ROSS 08-01-30-18 (TRU)	84.912	70.1643	70.1643
25041210800000	OP	DEVON	SANDS 07-19 SW NE	100	86.5925	86.5925
25041213610000	OP	DEVON	SANDS 13-14 SW SW	100	84.5551	84.5551
25041210560000	OP	DEVON	SANDS 15-01 NE SW	100	84	84
25041223560000	OBO	WESTERN NATURAL GAS INC	SANDS 16-18-32-15 SESE	50.801	42.6729	42.6729
25005214190000	OP	DEVON	ROSS 35-02-31-17	84.912	70.1643	70.1643
25005228250000	OP	DEVON	ROSS 35-05-31-17	84.912	70.1643	70.1643
25005228260000	OP	DEVON	ROSS 35-08-31-17	84.912	70.1643	70.1643
25005237100000	OP	DEVON	ROSS 35-13-31-17 (EAGLE)	84.912	70.1643	70.1643
25005214690000	OP	DEVON	ROSS 35-14-31-17	84.912	70.1643	70.1643
25041211050000	OP	DEVON	SANDS 17-01 SW SE	100	84	84
25041223670000	OP	DEVON	SANDS 31-01-32-15	93.1935	77.8471	77.8471
25041235430000	OP	DEVON	SANDS 31-04A-32-15	93.1935	77.8471	77.8471
25005225970000	OP	DEVON	ROSS 35-16-31-17	84.912	70.1643	70.1643
25005214000000	OP	DEVON	S B RANCH 02-11-30-18	84.912	70.1643	70.1643
25005227000000	OP	DEVON	S B RANCH 02-12-30-18	84.912	70.1643	70.1643
25005221110000	OBO	BROWN J BURNS OPERG CO	S B RANCH 04-30-19 SE NE NW	40.9312	35.7019	35.7019
25005211430000	OP	DEVON	SHANKLE 21-11-31-18	84.912	70.1643	70.1643
25005226200000	OBO	BROWN J BURNS OPERG CO	S B RANCH 04-30-19B	40.9312	35.7019	35.7019
25005216610000	OP	DEVON	S B RANCH 22-05-31-19	38.6841	32.328	32.328
25005233740000	OP	DEVON	S B RANCH 26-05-31-18	84.912	70.1643	70.1643
25005227120000	OP	DEVON	S B RANCH 26-15-31-18 (PAULSON)	84.912	70.1643	70.1643
25005217810000	OP	DEVON	S B RANCH 27-05-31-19	87.1681	72.3495	72.3495
25005050930000	OP	DEVON	SHEPARD (03-02-31-19)	100	87.5	87.5
25005216860000	OP	DEVON	O CONNELL 83-11-25-18	53.6439	43.7532	43.7532
25005053140000	OP	DEVON	O NEIL 01-08-31-17 (SENE)	84.912	70.1643	70.1643
25041219620000	OP	DEVON	O NEIL 05-16-31-17	83.5466	69.5783	69.5783
25041225960000	OP	DEVON	O NEIL 34-02-32-17	83.9063	70.973	70.973
25041229630000	OP	DEVON	O NEIL 35-13-32-17	84.912	70.1643	70.1643
25041227820000	OP	DEVON	O NEIL 35-15-32-17	84.912	70.1643	70.1643
25005233730000	OP	DEVON	OCONNELL-DIR 11-08-25-18	53.6439	43.9977	43.9977
25015212800000	OP	DEVON	OLSON 02-33 (33-12-27-17)	93.6762	80.5111	80.5111
25015214520000	OP	DEVON	OLSON 09-32 (32-09-27-17)	100	86.4375	86.4375
25041210030000	OP	DEVON	OLSON 15-11-31-17	84.912	70.1643	70.1643
25041226370000	OP	DEVON	OLSON 15-15-31-17 (TRU)	84.912	70.1643	70.1643
25005211830000	OP	DEVON	OLSON 18-11-31-18	84.912	70.1643	70.1643
25041234370000	OP	DEVON	OLSON 21-05-31-17	84.912	70.1643	70.1643
25041227790000	OP	DEVON	OLSON 21-10-31-17	84.912	70.1643	70.1643
25041225440000	OP	DEVON	OLSON 22-02-31-17	84.912	70.1643	70.1643
25041224510000	OP	DEVON	OLSON 22-07-31-17	84.912	70.1643	70.1643
25041225740000	OP	DEVON	OLSON 22-09-31-17	84.912	70.1643	70.1643
25005237030000	OP	DEVON	OLSON 23-03-31-17	84.912	70.1643	70.1643
25005211440000	OP	DEVON	OLSON 23-07-31-17	84.912	70.1643	70.1643
25005237040000	OP	DEVON	OLSON 23-12-31-17	84.912	70.1643	70.1643
25005210010000	OP	DEVON	OLSON 25-03-31-17	84.912	70.1643	70.1643
25005227640000	OP	DEVON	OLSON 25-04-31-17 (TRU)	84.912	70.1643	70.1643
25005214680000	OP	DEVON	OLSON 25-10-31-17	84.912	70.1643	70.1643
25005226660000	OP	DEVON	OLSON 25-12-31-17	84.912	70.1643	70.1643
25005237190000	OP	DEVON	OLSON 25-14-31-17	84.912	70.1643	70.1643
25005237200000	OP	DEVON	OLSON 25-16-31-17	84.912	70.1643	70.1643
25005237210000	OP	DEVON	OLSON 25-16A-31-17	84.912	70.1643	70.1643
25005223650000	OP	DEVON	OLSON 26-09-31-17	84.912	70.1643	70.1643
25005237090000	OP	DEVON	OLSON 26-10-31-17	84.912	70.1643	70.1643
25005227650000	OP	DEVON	OLSON 26-15-31-17 (TRU)	84.912	70.1643	70.1643
25041224790000	OP	DEVON	OLSON 27-14-31-17	84.912	70.1643	70.1643
25041226890000	OP	DEVON	OLSON 27-16-31-17	84.912	70.1643	70.1643
25005217370000	OP	DEVON	OLSON 30-06-31-18	84.912	70.1643	70.1643
25005227580000	OP	DEVON	OLSON 30-10-31-18	84.912	70.1643	70.1643
25005232120000	OP	DEVON	OLSON 30-12-31-18	84.912	70.1643	70.1643
25015216850000	OP	DEVON	OLSON 32-08-27-17	100	87.375	87.375
25015218150000	OP	DEVON	OLSON 33-13-27-17	70.9191	59.2783	59.2783
25041227330000	OP	DEVON	OLSON 34-03-31-17	84.912	70.1643	70.1643
25041226450000	OP	DEVON	OLSON 34-04-31-17	84.912	70.1643	70.1643
25041227340000	OP	DEVON	OLSON 34-05-31-17	84.912	70.1643	70.1643
25041234390000	OP	DEVON	OLSON-DIR 22-10-31-17	84.912	70.1643	70.1643
25041233170000	OP	DEVON	ONEIL 33-12-32-17	68.3817	58.5849	58.5849
X	OP	DEVON	OTHER BEAR PAW - P&A PROJECTION	100	100	100
25041222180000	OBO	WESTERN NATURAL GAS INC	PARENT 10-06	24	19.7231	19.7231
25005223590000	OP	DEVON	PAULSEN 15-14-31-18	84.912	70.1643	70.1643
25005223620000	OP	DEVON	PAULSEN 21-01-31-18	84.912	70.1643	70.1643
25005222760000	OP	DEVON	PAULSEN 27-01-31-18	84.912	70.1643	70.1643
25005228460000	OP	DEVON	PAULSEN 27-08-31-18	84.912	70.1643	70.1643
25005227130000	OP	DEVON	PAULSEN 30-16-31-18	84.912	70.1643	70.1643
25005232940000	OP	DEVON	PAULSEN 31-02-31-18	84.912	70.1643	70.1643
25005223340000	OP	DEVON	PAULSEN 31-05-31-18	84.912	70.1643	70.1643
25005227610000	OP	DEVON	PAULSEN 32-02-31-18 (TRU)	84.912	70.1643	70.1643
25005235790000	OP	DEVON	PAULSEN-DIR 15-09-31-18	84.912	70.1643	70.1643

25005237110000	OP	DEVON	PAULSEN-DIR 31-01-31-18	84.912	70.1643	70.1643
25005212440000	OP	DEVON	REED 01-11 (11-11-27-18)	99.8523	85.8628	85.8628
25005216450000	OP	DEVON	REED 04-01 (01-16-27-18)	91.6986	78.8715	78.8715
25015215210000	OP	DEVON	PHILLIPS 04-04-26-17	53.5697	42.1879	42.1879
25005236620000	OP	DEVON	POWELL-DIR 35-10-27-20	100	85.3379	85.3379
25005050460000	OP	DEVON	PRIMM 2 (10-03-31-19)	100	99	99
25015214730000	OP	DEVON	PURSLEY 07-17 (17-07-28-14)	100	87.5	87.5
25041226810000	OP	DEVON	PURSLEY 28-14-32-14 (NON UNIT BH)	94.9878	79.8725	79.8725
25041227740000	OP	DEVON	PURSLEY 29-09-32-14	89.9908	74.7991	0
25005230210000	OBO	KOGI	PURSLEY FEDERAL 26-35	0.2083	0.1823	0.1823
25015216820000	OP	DEVON	U S 33-04-27-17	93.6762	80.5111	80.5111
25005219050000	OP	DEVON	U S 3-1 (01-03-26-17)	75.0346	63.8146	63.8146
25015217490000	OP	DEVON	U S 30-03-27-17	100	86.3752	86.3752
25015217770000	OP	DEVON	U S 33-02-27-17	81.1762	69.6319	69.6319
25005224630000	OP	DEVON	U S 34-07-26-19	53.6439	43.7782	43.7782
25041221720000	OP	DEVON	U S 34-16-31-17	84.912	70.1643	70.1643
25005216980000	OP	DEVON	U S 86-18-26-18	53.6439	43.7532	43.7532
25005213460000	OP	DEVON	WILLIAMSON 68-09-26-19	53.6439	43.7532	43.7532
25005229480000	OP	DEVON	WILLIAMSON 04-12-31-18	84.912	70.1643	70.1643
25005219480000	OP	DEVON	WILLIAMSON 05-12-31-18	84.912	70.1643	70.1643
25005232340000	OP	DEVON	WILLIAMSON 12-16B-26-18	53.6439	44.1478	44.1478
25005237780000	OP	DEVON	WILLIAMSON-DIR 07-01-31-18	84.912	70.1643	70.1643
25005051320000	OP	DEVON	WM BOWES (34-06-32-19)	100	87.5	87.5
25005234970000	OP	DEVON	WORTMAN 23-12-25-18	54.0266	44.6254	44.6254
25005232480000	OBO	BROWN J BURNS OPERG CO	WRIGHT 06-32-198	5.5461	4.8529	4.8529
25041221580000	OP	DEVON	YATES 34-08-32-14	94.9878	77.0269	77.0269
25041222800000	OP	DEVON	WODARZ 26-11-32-14	93.1935	77.8471	77.8471
25005235440000	OP	DEVON	US 03-06-26-20	100	86	86
25005233090000	OP	DEVON	US 09-09-26-20	100	86	86
25005233690000	OP	DEVON	US 14-16-27-18	75.0461	62.3654	62.3654
25005228110000	OP	DEVON	US 15-09-27-18	92.3219	78.8896	78.8896
25005230290000	OP	DEVON	US 15-11X-27-18	92.3768	78.9377	78.9377
25005230300000	OP	DEVON	US 17-07-27-19	100	86.0625	86.0625
25005237330000	OP	DEVON	US 19-14-27-20	100	87.5	87.5
25005228120000	OP	DEVON	US 21-02-27-18	78.8852	66.0015	66.0015
25005229140000	OP	DEVON	US 24-01-27-18	100	85.3125	85.3125
25005235830000	OP	DEVON	US 24-05-25-18	53.8976	42.5151	42.5151
25005234610000	OP	DEVON	US 27-10-25-18	49.0797	40.0942	40.0942
25005234450000	OP	DEVON	US 32-03-25-18	54.4094	44.7577	44.7577
25005232540000	OP	DEVON	US 33-07-28-19	90.625	78.2553	78.2553
25005236450000	OP	DEVON	US-DIR 01-04-26-20	100	86.0924	86.0924
25005233370000	OP	DEVON	US-DIR 01-08-27-18	91.778	78.7837	78.7837
25005233380000	OP	DEVON	US-DIR 01-09-27-18	80.3551	69.1574	69.1574
25005219830000	OP	DEVON	WEAVER 07-03 (03-07-26-17)	89.9337	76.0797	76.0797
X	OP	DEVON	2012 BEAR PAW CAPITAL ADJUSTME	100	100	100
X	OP	DEVON	2013 BEAR PAW EQUIP UPGRADE	100	100	100
X	OP	DEVON	2013 BEAR PAW P&A WELLS	100	100	100
25041221550000	OP	DEVON	WAVRICK 25-02-31-14	93.1935	77.8471	77.8471
25015211960000	OP	DEVON	WEAVER 02-26 (26-06-27-16)	100	86.375	86.375
25005232570000	OP	DEVON	WEAVER 03-01-26-17	90.0075	76.1443	76.1443
25015216330000	OP	DEVON	WEAVER 04-25 (25-04-27-16)	100	86.4483	86.4483
25015213880000	OP	DEVON	WEAVER 11-26 (26-11-27-16)	100	86.5	86.5
25015213850000	OP	DEVON	WEAVER 13-25 (25-13-27-16)	100	86.4483	86.4483
25015216870000	OP	DEVON	WEAVER 22-12-27-16	100	86.375	86.375
25005233580000	OP	DEVON	US-DIR 01-14-27-18	91.6994	78.7256	78.7256
25005233390000	OP	DEVON	US-DIR 01-9A-27-18	91.769	78.7158	78.7158
25005234980000	OP	DEVON	US-DIR 02-05-25-18	54.5559	47.2733	47.2733
25005233700000	OP	DEVON	US-DIR 06-12-27-19	68.9322	59.4697	59.4697
25005236650000	OP	DEVON	US-DIR 07-01-27-19	92.6461	79.045	79.045
25005237520000	OP	DEVON	US-DIR 18-03-25-18	60.7177	51.61	51.61
25005237490000	OP	DEVON	US-DIR 18-09-25-18	68.0684	57.8581	57.8581
25005236990000	OP	DEVON	US-DIR 19-06-25-18	54.4094	44.7577	44.7577
25005235000000	OP	DEVON	US-DIR 20-08-25-18	54.4094	44.7577	44.7577
25015217460000	OP	DEVON	WEAVER 28-07-27-16	100	86.5	86.5
25015218140000	OP	DEVON	WEAVER 28-7A-27-16	100	77.8471	77.8471
25015216760000	OP	DEVON	WEAVER CATTLE CO-FED 9-26-16	77.2047	65.6285	65.6285
25015218130000	OP	DEVON	WEAVER-DIR 28-06-27-16	100	86.5	86.5
25005221370000	OBO	BROWN J BURNS OPERG CO	WERK 21-32-18	47.3874	40.355	40.355
25005221320000	OBO	BROWN J BURNS OPERG CO	WERK 22-32-18	21.4328	19.0357	19.0357
25041217060000	OBO	BROWN J BURNS OPERG CO	WIGMORE 30-01	0.4326	0.3622	0.3622
25005228330000	OP	DEVON	U S 03-14-30-17	84.912	70.1643	70.1643
25005221720000	OP	DEVON	U S 02-16C-25-18	53.6439	43.9977	43.9977
25005223700000	OP	DEVON	U S 03-06-30-17	84.912	70.1643	70.1643
25005227530000	OP	DEVON	U S 03-11-30-17 (TRU)	84.912	70.1643	70.1643
25005227750000	OP	DEVON	U S 03-16-26-17	89.9337	76.0797	76.0797
25005219810000	OP	DEVON	U S 04-03-30-18	84.912	70.1643	70.1643
25005235880000	OP	DEVON	US-DIR 22-01-25-18	54.4094	44.7923	44.7923
25005237460000	OP	DEVON	US-DIR 25-03-25-17	58.6448	47.5023	47.5023
25041234420000	OP	DEVON	US-DIR 25-10-31-15	91.6329	74.1164	74.1164
25005237470000	OP	DEVON	US-DIR 25-10A-25-17	58.6448	47.6031	47.6031
25005237480000	OP	DEVON	US-DIR 25-11-25-17	58.6448	47.6031	47.6031

25005237510000	OP	DEVON	US-DIR 26-08-25-17	53.4644	45.4447	45.4447
25005234990000	OP	DEVON	US-DIR 28-01-25-18	51.1429	44.75	44.75
25005237360000	OP	DEVON	US-DIR 30-10-27-20	100	87.5	87.5
25005235960000	OP	DEVON	US-DIR 32-01-25-18	54.8894	45.1572	45.1572
25005236670000	OP	DEVON	US-DIR 34-16-27-20	100	85.9347	85.9347
25005236680000	OP	DEVON	US-DIR 35-12-27-20	100	85.6689	85.6689
25041226020000	OP	DEVON	U S 06-07X-30-16	93.1935	77.8471	77.8471
25005221730000	OP	DEVON	U S 06-15-25-18	53.6439	43.7532	43.7532
25005217180000	OP	DEVON	U S 06-28-25-19	53.6439	43.7532	43.7532
25005225200000	OP	DEVON	U S 07-11-25-18	53.6439	43.7582	43.7582
25005224510000	OP	DEVON	U S 07-13-30-18	84.912	70.1643	70.1643
25005227760000	OP	DEVON	U S 08-09-26-19	53.6439	43.7532	43.7532
25015214220000	OP	DEVON	U S 09-08-25-17	47.5733	40.0709	40.0709
25005219800000	OP	DEVON	U S 10-04-30-18	84.912	70.1643	70.1643
25005227100000	OP	DEVON	U S 10-05-30-18	84.912	70.1643	70.1643
25005224660000	OP	DEVON	U S 13-09-26-18	53.6439	43.9033	43.9033
25005223210000	OP	DEVON	VERCRUYSSEN 19-04-31-18	84.912	70.1643	70.1643
25005236280000	OP	DEVON	VERCRUYSSEN 19-06-31-18	84.912	70.1643	70.1643
25005237050000	OP	DEVON	VERCRUYSSEN 24-01-31-17	84.912	70.1643	70.1643
25005237060000	OP	DEVON	VERCRUYSSEN 19-06A-31-18	84.912	70.1643	70.1643
25005224720000	OP	DEVON	VERCRUYSSEN 23-01-31-17	84.912	70.1643	70.1643
25041218240000	OP	DEVON	WARITZ 05-11-31-15	93.1935	77.8471	77.8471
25005229430000	OP	DEVON	U S 15-06-27-18	92.3768	78.9377	78.9377
25041222390000	OP	DEVON	U S 15-12-30-15	93.1935	77.8471	77.8471
25041220220000	OP	DEVON	U S 15-14-30-15	93.1935	77.8471	77.8471
25005232560000	OP	DEVON	U S 15-15-25-18	53.6439	44.2494	44.2494
25005232530000	OP	DEVON	U S 18-12-26-19	53.6439	43.9033	43.9033
25015216830000	OP	DEVON	U S 19-01-27-17	100	86.125	86.125
25015217510000	OP	DEVON	U S 19-15-27-17	100	86.125	86.125
25015216810000	OP	DEVON	U S 20-05-27-17	100	86.3125	86.3125
25041210170000	OP	DEVON	WILEY 09-06-31-17	100	87.5	87.5
25041226360000	OP	DEVON	WILEY 09-11-31-17	100	87.5	87.5
25041215510000	OP	DEVON	WILEY 09-16-31-17	100	87.5	87.5
25041211410000	OP	DEVON	WILEY 17-07-31-17 (7-17-31-17)	99.0123	86.503	86.503
25005232620000	OP	DEVON	U S 21-15-31-19	84.6195	70.7374	70.7374
25041221740000	OP	DEVON	U S 22-06-30-15	93.1935	77.8471	77.8471
25041222410000	OP	DEVON	U S 22-13-30-15	93.1935	77.8471	77.8471
25005232520000	OP	DEVON	U S 24-01A-26-18	42.3387	38.1905	38.1905
25005220670000	OP	DEVON	U S 25-10-25-17	52.5395	42.64	42.64
25005224280000	OP	DEVON	U S 26-14-25-18	54.4094	44.4037	44.4037
25005221150000	OP	DEVON	U S 27-06-31-18	84.912	70.1643	70.1643
25005225380000	OP	DEVON	U S 27-15-26-19	53.6439	43.7782	43.7782
25005230440000	OP	DEVON	U S 28-01-25-19	53.6439	43.9977	43.9977
25005226640000	OP	DEVON	U S 28-13-26-18	54.4094	45.2827	45.2827
25005226340000	OP	DEVON	U S 29-02-26-18	54.4094	44.7577	44.7577
25041235160000	OP	DEVON	BROWN 13-04-31-14	93.1935	77.8471	77.8471

Date: 9/27/2012

STEPHAN R SMITH - P E
Consulting Petroleum Engineer
Annual CashFlow - Summary

Time: 1:25 PM

Date	Well Count	Gross Production Oil (Bbl)	Gross Production Gas (Mcf)	Net Production Oil (Bbl)	Net Production Gas (Mcf)	Average Prices Oil ($/Bbl)	Average Prices Gas ($/Mcf)	Sales Total ($)
12/2013	795	0	7,905,821	0	5,595,553	0.00	3.11	17,425,524
12/2014	789	0	7,048,447	0	4,992,618	0.00	3.50	17,457,894
12/2015	784	0	6,365,977	0	4,513,536	0.00	3.69	16,655,566
12/2016	776	0	5,792,735	0	4,110,249	0.00	3.86	15,877,269
12/2017	769	0	5,302,715	0	3,765,345	0.00	4.04	15,227,362
12/2018	760	0	4,875,424	0	3,464,639	0.00	4.13	14,299,043
12/2019	751	0	4,498,786	0	3,199,781	0.00	4.21	13,475,545
12/2020	741	0	4,163,478	0	2,964,071	0.00	4.30	12,738,458
12/2021	728	0	3,857,253	0	2,748,683	0.00	4.39	12,054,770
12/2022	713	0	3,577,160	0	2,550,913	0.00	4.48	11,416,176
12/2023	696	0	3,318,792	0	2,368,694	0.00	4.57	10,817,519
12/2024	683	0	3,085,438	0	2,203,508	0.00	4.66	10,268,189
12/2025	667	0	2,869,619	0	2,051,815	0.00	4.76	9,757,082
12/2026	650	0	2,671,359	0	1,912,048	0.00	4.85	9,278,011
12/2027	633	0	2,488,797	0	1,783,036	0.00	4.95	8,828,225
Remainder:		0	22,721,146	0	16,358,929	0.00	5.46	89,301,466
Grand Total:		0	90,542,947	0	64,583,418	0.00	4.41	284,878,098

Date	Operating Expenses ($)	Taxes ($)	Operating Income ($)	Other Costs ($)	Periodic Cash Flow ($)	Cumulative Cash Flow ($)	10% Cash Flow ($)
12/2013	1,779,466	1,742,552	13,903,506	0	13,903,506	13,903,506	13,209,949
12/2014	1,765,236	1,745,789	13,946,868	0	13,946,868	27,850,374	12,052,778
12/2015	1,755,637	1,665,557	13,234,373	0	13,234,373	41,084,747	10,399,727
12/2016	1,735,223	1,587,727	12,554,319	0	12,554,319	53,639,066	8,968,034
12/2017	1,717,548	1,522,736	11,987,077	0	11,987,077	65,626,143	7,786,088
12/2018	1,697,119	1,429,904	11,172,020	0	11,172,020	76,798,163	6,596,757
12/2019	1,676,082	1,347,555	10,451,909	0	10,451,909	87,250,072	5,610,357
12/2020	1,655,226	1,273,846	9,809,386	0	9,809,386	97,059,458	4,786,717
12/2021	1,627,532	1,205,477	9,221,760	0	9,221,760	106,281,218	4,090,847
12/2022	1,594,548	1,141,618	8,680,010	0	8,680,010	114,961,228	3,500,453
12/2023	1,556,144	1,081,752	8,179,624	0	8,179,624	123,140,852	2,998,761
12/2024	1,525,243	1,026,819	7,716,127	0	7,716,127	130,856,978	2,571,651
12/2025	1,493,249	975,708	7,288,125	0	7,288,125	138,145,103	2,208,171
12/2026	1,459,246	927,801	6,890,964	0	6,890,964	145,036,067	1,898,025
12/2027	1,422,944	882,822	6,522,459	0	6,522,459	151,558,526	1,633,193
Remainder:	16,504,078	8,930,147	63,867,241	0	63,867,241	215,425,767	8,982,135
Grand Total:	40,964,521	28,487,810	215,425,767	0	215,425,767	215,425,767	97,293,645

Discount Present Worth:

0.00 %	215,425,767
5.00 %	135,807,712
10.00 %	97,293,645
15.00 %	75,726,380
17.00 %	69,631,585
20.00 %	62,219,371
25.00 %	53,032,464
30.00 %	46,393,093
50.00 %	31,681,484
75.00 %	23,470,261
100.00 %	19,094,374

Economic Dates:

Effective Date	01/2013
Calculated Limit	12/2042
Economic Life	360 Months
	30 Years 0 Months

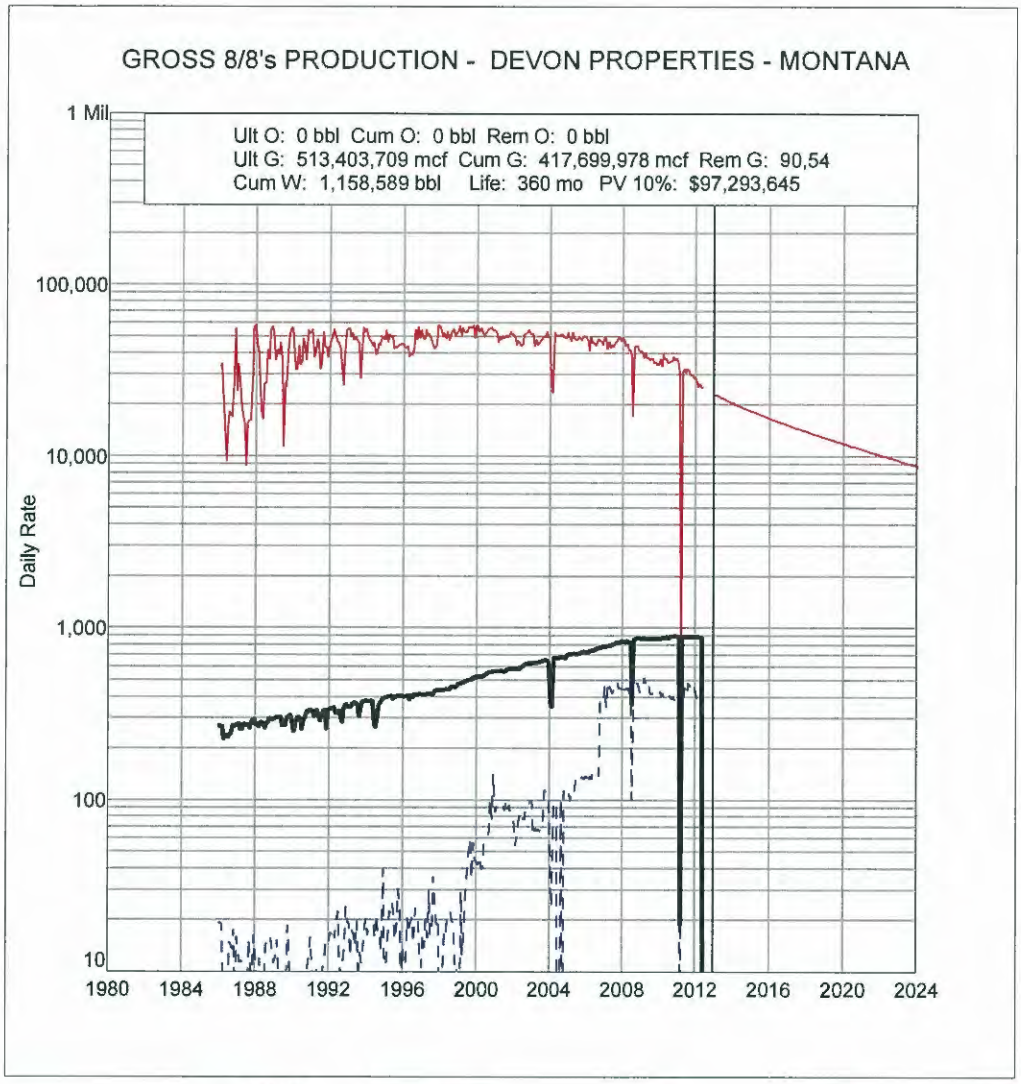
Economics Information:

Net Payout Date:	01/2013
Rate of Return:	>100 %
Return on Investment:	0.00
Disc Return on Invest:	0.00

Economics Summary:

	Bbl Oil	Mcf Gas
Ultimate Gross	0	513,403,709
Historic Gross	0	417,699,978
Gross at Eff Date	0	422,860,762
Remaining Gross	0	90,542,947
Remaining Net	0	64,583,418

: NORTHWESTERN ENERGY
:
: EVALUATION OF DEVON PROPERTIES
:
: AS OF DATE: JANUARY 1, 2013



Date	Well Count	Days On	Oil (bbl)	Gas (mcf)	Water (bbl)	Injection (bbl)
Previous		1,267	0	407,287,606	1,004,893	0
06/2011	881	0	0	940,219	13,842	0
07/2011	887	0	0	983,693	12,662	0
08/2011	887	0	0	962,821	14,503	0
09/2011	889	0	0	907,253	14,110	0
10/2011	882	0	0	915,277	13,078	0
11/2011	887	0	0	867,850	13,751	0
12/2011	883	0	0	877,924	13,829	0
01/2012	883	0	0	837,376	12,493	0
02/2012	884	0	0	773,241	11,619	0
03/2012	884	0	0	808,089	11,443	0
04/2012	876	0	0	768,130	11,162	0
05/2012	868	0	0	770,499	11,204	0
Total:		1,267	0	417,699,978	1,158,589	0

Economics Summary:

	Bbl Oil	Mcf Gas
Ultimate Gross	0	513,403,709
Historic Gross	0	417,699,978
Gross at Eff Date	0	422,860,762
Remaining Gross	0	90,542,947
Remaining Net	0	64,583,418

Economic Dates:

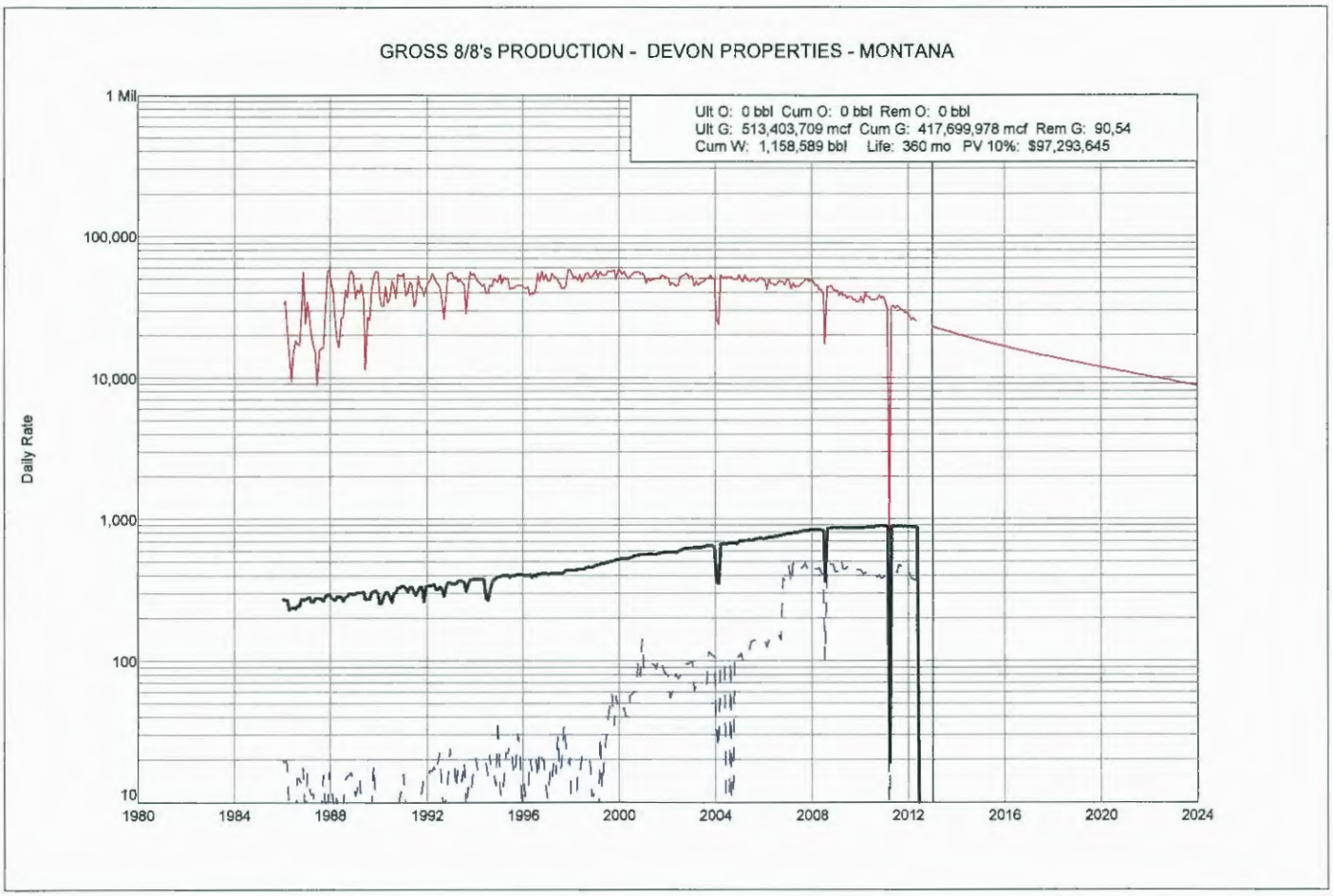
Effective Date	01/2013
Calculated Limit	12/2042
Economic Life	360 Months
	30 Years 0 Months

Rate/Time Graph

Project: c:\users\stephan r smith\documents\ihs\powertools\projects v9.1\nwe-devon pdp v9.1

Date: 9/27/2012
Time: 1:26 PM

Summary Lease Report



Exhibit__(PEC-15) has been provided only on the attached CD.

Date: 7/6/2015

NWE - Black Hills - All properties

Summary Lease Report

Date	Well Count	Gross Production Oil (Bbl)	Gross Production Gas (Mcf)	Net Production Oil (Bbl)	Net Production Gas (Mcf)	Average Prices Oil ($/Bbl)	Average Prices Gas ($/Mcf)	Sales Total ($)
12/2015	54	2,329	360,727	366	65,430	50.00	1.45	113,174
12/2016	52	3,568	554,837	561	100,337	50.00	1.62	190,581
12/2017	50	3,093	493,457	486	89,059	50.00	1.73	178,376
12/2018	50	2,682	447,691	421	80,776	50.00	2.01	183,429
12/2019	49	2,325	405,785	365	73,174	50.00	2.30	186,567
12/2020	46	2,015	360,887	317	65,337	50.00	2.45	175,912
12/2021	45	1,747	327,534	275	59,282	50.00	2.56	165,491
12/2022	41	1,515	289,537	238	52,167	50.00	2.73	154,316
12/2023	38	1,313	258,662	206	46,557	50.00	2.87	143,935
12/2024	37	1,138	237,145	179	42,778	50.00	3.02	138,135
12/2025	34	987	210,009	155	37,757	50.00	3.24	130,086
12/2026	33	856	193,562	134	34,782	50.00	3.31	121,850
12/2027	32	742	176,804	117	31,609	50.00	3.39	112,982
12/2028	28	643	155,582	101	27,824	50.00	3.50	102,438
12/2029	27	557	143,158	88	25,631	50.00	3.57	95,882
Remainder:		2,213	2,243,737	348	387,714	50.00	4.69	1,835,426
Grand Total:		27,723	6,859,114	4,357	1,220,214	50.00	3.12	4,028,581

Date	Operating Expenses ($)	Taxes ($)	Operating Income ($)	Other Costs ($)	Periodic Cash Flow ($)	Cumulative Cash Flow ($)	10% Cash Flow ($)
12/2015	52,909	10,525	49,740	0	49,740	49,740	48,220
12/2016	86,032	17,724	86,825	0	86,825	136,565	78,157
12/2017	82,852	16,589	78,935	0	78,935	215,500	64,593
12/2018	82,208	17,059	84,163	0	84,163	299,663	62,602
12/2019	80,873	17,351	88,344	0	88,344	388,007	59,732
12/2020	76,825	16,360	82,727	0	82,727	470,733	50,847
12/2021	74,833	15,391	75,268	0	75,268	546,001	42,057
12/2022	68,416	14,351	71,548	0	71,548	617,550	36,341
12/2023	63,789	13,386	66,760	0	66,760	684,310	30,825
12/2024	62,669	12,847	62,619	0	62,619	746,928	26,284
12/2025	56,652	12,098	61,336	0	61,336	808,265	23,403
12/2026	55,493	11,332	55,025	0	55,025	863,290	19,087
12/2027	52,917	10,507	49,558	0	49,558	912,848	15,628
12/2028	47,318	9,527	45,593	0	45,593	958,441	13,070
12/2029	45,796	8,917	41,169	0	41,169	999,610	10,729
Remainder:	743,268	170,695	921,464	0	921,464	1,921,074	74,024
Grand Total:	1,732,849	374,658	1,921,074	0	1,921,074	1,921,074	655,600

Discount Present Worth:

0.00 %	1,921,074
10.00 %	655,600
20.00 %	408,450
30.00 %	300,477
40.00 %	240,117
50.00 %	201,659
60.00 %	175,051
70.00 %	155,561
80.00 %	140,669
90.00 %	128,917
100.00 %	119,400

Economic Dates:

Effective Date	06/2015
Calculated Limit	05/2115
Economic Life	1200 Months
	100 Years 0 Months

Economics Information:

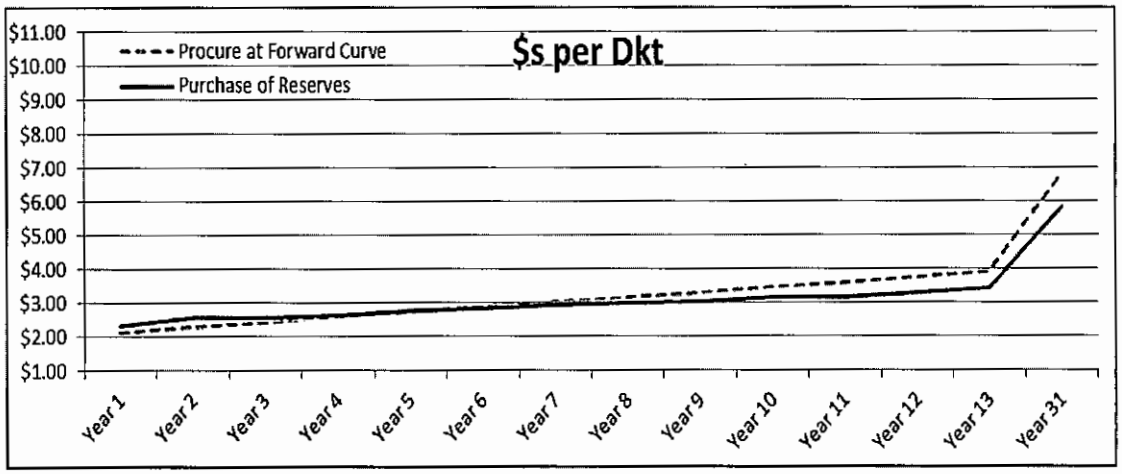
Net Payout Date:	06/2015
Rate of Return:	>100 %
Return on Investment:	0.00
Disc Return on Invest:	0.00

Economics Summary:

	Bbl Oil	Mcf Gas
Ultimate Gross	199,552	83,466,676
Historic Gross	171,127	76,495,764
Gross at Eff Date	171,829	76,607,561
Remaining Gross	27,723	6,859,114
Remaining Net	4,357	1,220,214

NorthWestern Energy
Preliminary natural gas acquisition analysis
Confidential and for management discussion only

Black Hills - extra wells



Scenario:	**Total PDP**
Bid	$ 505.00
Total rate base estimate	**$505.00**

Authorized ROE (Per 4/2013 Stip)	9.80%
Cost of Debt	4.00%
Equity % of Cap Structure	47.67%
Weighted Average Cost of Capital (WACC)	6.77%

Purchase of Reserves	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 31
Average Rate Base ($000's)	489	450	404	363	326	293	263	237	213	192	173	155	140	17
Production (Bcf)	0.07	0.11	0.10	0.09	0.08	0.07	0.07	0.06	0.05	0.05	0.04	0.04	0.03	0.01
Estimated Revenue Requirement ($000's)	$167	$287	$255	$238	$224	$205	$193	$173	$157	$150	$133	$126	$119	$30
Resulting owned forward prices ($/DKT)	$2.31	$2.56	$2.56	$2.64	$2.74	$2.81	$2.93	$2.99	$3.03	$3.17	$3.17	$3.28	$3.43	$5.83
Year NPV of revenue requirement ($000's)	**$1,990**													
20 Yr Levelized Price	**$2.81**	**$173**	**62**											
30 Yr Levelized Price	**$2.87**	**$154**	**54**											

Procure at Forward Curve														
Forward market price curve	$ 2.12	$ 2.29	$ 2.43	$ 2.59	$ 2.74	$ 2.88	$ 3.01	$ 3.15	$ 3.29	$ 3.44	$ 3.60	$ 3.76	$ 3.93	$ 6.82
Revenue Requirement ($000's)	$ 153	$ 257	$ 243	$ 234	$ 224	$ 210	$ 199	$ 183	$ 171	$ 163	$ 151	$ 145	$ 137	$ 35
Year NPV of revenue requirement ($000's)	**$2,071**		***Or***	***4.07%***	***greater than purchase option***									
20 Yr Levelized Price	**$2.89**	**$178**	**62**											
30 Yr Levelized Price	**$2.98**	**$161**	**54**											

Project: Black Hills - extra wells
Quoted Curve: AECO - 10
Quote Date: July 6, 2015 Steve Lewis

Year	Well Count (net)	Annual Production (Mdkt/yr)	Market Curve ($/dkt)	Revenue Credit (oil sales, other) [enter as positive no.]	Op. Expense + Property Taxes	Gathering & Transmission $1.00
Year 1	15	72.3	$2.12	$15,758	$44,872.86	$72,300
Year 2	12.4	112.4	$2.29	$23,987	$72,900.36	$112,400
Year 3	12	99.8	$2.43	$20,603	$70,159.77	$99,800
Year 4	11.8	90.3	$2.59	$17,670	$69,604.77	$90,300
Year 5	11.3	81.7	$2.74	$15,127	$68,454.81	$81,700
Year 6	11	72.8	$2.88	$12,922	$64,967.19	$72,800
Year 7	10.2	66	$3.01	$11,011	$63,248.91	$66,000
Year 8	9.6	58.1	$3.15	$9,354	$57,720.00	$58,100
Year 9	9.4	51.8	$3.29	$7,917	$53,731.77	$51,800
Year 10	8.6	47.4	$3.44	$6,673	$52,767.18	$47,400
Year 11	8.5	41.9	$3.60	$5,593	$47,581.26	$41,900
Year 12	8.2	38.5	$3.76	$4,657	$46,582.26	$38,500
Year 13	7.4	34.8	$3.93	$3,845	$44,362.26	$34,800
Year 14	7.2	30.7	$4.11	$3,142	$39,537.09	$30,700
Year 15	7	28.1	$4.30	$2,532	$38,225.07	$28,100
Year 16	6.7	25.5	$4.49	$2,073	$36,361.38	$25,500
Year 17	6.4	23	$4.69	$1,697	$34,587.60	$23,000
Year 18	6	20.8	$4.90	$1,390	$32,900.40	$20,800
Year 19	5.8	19	$5.13	$1,138	$31,296.45	$19,000
Year 20	5.5	17.1	$5.36	$0	$29,770.20	$17,100
Year 21	5.3	15.5	$5.60	$0	$28,318.32	$15,500
Year 22	5.2	13.9	$5.71	$0	$26,936.37	$13,900
Year 23	5	12.6	$5.82	$0	$25,623.24	$12,600
Year 24	4.8	11.4	$5.94	$0	$24,373.38	$11,400
Year 25	4.6	10.3	$6.06	$0	$23,184.57	$10,300
Year 26	4.5	9.3	$6.18	$0	$22,053.48	$9,300
Year 27	4.4	8.4	$6.30	$0	$20,977.89	$8,400
Year 28	4.2	7.6	$6.43	$0	$19,955.58	$7,600
Year 29	4.1	6.3	$6.56	$0	$18,982.11	$6,320
Year 30	4	5.7	$6.69	$0	$18,056.37	$5,720
Year 31	3.8	5.2	$6.82	$0	$17,176.14	$5,180
Year 32	3.7	4.7	$6.96	$0	$16,338.09	$4,680
Year 33	3.6	4.2	$7.10	$0	$15,541.11	$4,240
Year 34	3.5	3.8	$7.24	$0	$14,782.98	$3,830
Year 35	3.4	3.5	$7.38	$0	$14,062.59	$3,470
Year 36	3.3	3.1	$7.53	$0	$13,376.61	$3,140
Year 37	3.2	2.8	$7.68	$0	$12,723.93	$2,840
Year 38	3.1	2.6	$7.83	$0	$12,103.44	$2,570
Year 39	3.1	2.3	$7.99	$0	$11,512.92	$2,330
Year 40	3	2.1	$8.15	$0	$10,951.26	$2,100
Year 41	2.9	1.9	$8.31	$0	$10,417.35	$1,904
Year 42	2.8	1.7	$8.48	$0	$9,908.97	$1,720
Year 43	2.8	1.6	$8.65	$0	$9,426.12	$1,560
Year 44	2.7	1.4	$8.82	$0	$8,966.58	$1,410
Year 45	2.7	1.3	$9.00	$0	$8,528.13	$1,276
		1,175.29		$ -	$1,413,909	$1,175,291

Other Inputs	
Purchase Price	$505,000
Capital Financed with Debt:	52.33%
Capital Financed with Equity:	47.67%
Cost of Debt	4.00%
Allowed Return on Equity	9.80%
Return on Rate Base	6.77%
Abandonment Costs	$10,000
Salvage Value (% of Aband.)	60%
Production Taxes	8.46%
MCC / MPSC tax (% of tot revenue)	0.53%
Federal Income Tax	35.00%
MT Corporate Income Tax	6.75%
Federal plus State Composite Tax Rate	39.39%
Purchase Price Allocation	
Production (depletable)	100.00%
Gathering (depletable)	0.00%
Separating / Processing (depreciable)	0.00%
Land (non-depreciable)	0.00%
Depreciable Book Life (5 - 30 Years)	30
Depreciable Tax Life (drop down list)	15
Production life for evaluation	45
Estimated cost per Dkt	$0.43
Checks	
Unregulated DCF Balanced	TRUE
Deferred Tax Liability Consumed	TRUE
Assets fully depreciated	TRUE
Reserves fully depleted	TRUE
Earned ROE vs Authorized	TRUE

NorthWestern Energy
Purchase price summary-Lodge Creek & Willow Creek

Purchase price for 75% interest in LLC's		
Purchase price per PSA, Section 3.1	$	2,420,000
Adjustment per PSA, Section 3.3(a)(i)		206,998
Other		40,000
Total per Pat Callahan email-10/12/12	$	2,666,998
Interest acquired		75%
Total value of LLC's based on purchase price	$	3,555,997
Interest owned by Black Hills		25%
Potential value of remaining interest based on our purchase	$	888,999

Exhibit__(PEC-19) and Exhibit__(PEC-20)

have been provided only on the attached CD.

Recent Small Interest Purchases

10/13	Cardinal	Royalty and Working Interests	$42,860
12/13	Cardinal	Royalty	$1,960
1/14	Sabal/Landress	Royalty and Working Interests	$14,025
4/14	Tanya Mayn	Working Interest	$255
5/14	Wyatt Culbert	Royalty	$500
8/14	Pickens Financial	Royalty and Working Interests	$13,000
9/14	Kenneth Cory	Royalty and Working Interests	$40,000
10/14	Chick/Wizco	Royalty	$6,000
11/14	Dave Egleston	Royalty	$775
11/14	Anita Mraz	Royalty	$540
11/14	Laure Claudle	Royalty	$540
12/14	Pam Scott	Working Interest	$200
1/15	Delbert Schnitzmeier	Royalty	$4,600
2/15	Tarey Mayn	Working Interest	$100
4/15	Artz Family Trust	Royalty Interest	$450
4/15	Eva Virgin	Royalty Interest	$565
8/15	Wilbanks Res	Working Interest	$18,000
8/15	Maxcy	Royalty Interest	$150
1/16	Gordon Boyce	Royalty Interest	$5,600
1/16	Christie Minnie	Royalty Interest	$475
1/16	Sisters of Providence	Royalty Interest	$4,200
5/16	Shirley Brown Omlie	Royalty Interest	$1150

Justification or $50.00 offer for Royalty Interests

Year	Actual Payment	One Check	1099	Total	NPV-10
1	$ 10.13	$ 5.40	$ 5.40	$ 20.93	$52.05
2	$ 10.13	$ 5.40	$ 5.40	$ 20.93	
3	$ 10.13	$ 5.40	$ 5.40	$ 20.93	

	Actual Payment	Two Check	1099	Total	NPV-10
1	$ 10.13	$ 10.80	$ 5.40	$ 26.33	$45.70
2	$ 10.13	$ 10.80	$ 5.40	$ 26.33	

Actual Payment - this is based on the actual royalties paid on the last 3 payees offered $50.00
Check Cost - this is from the US Bank 2016 costs - assumes average back pages
1099 Cost - assumed to be the same as a check

Not included:

tracking payments, taxes, address
withholding production taxes and forwarding to the State
risks of splitting interest into two or three Heirs

Three year pay out justifys minimum of $50.00

Recent Minimum Interest Purchases

4/15	Rene Brunet	Royalty Interest	$50
7/15	Hans Tvedte	Royalty Interest	$50
7/15	Terry Merwin	Royalty Interest	$50
4/16	Margie Kay McGavern	Royalty Interest	$50
6/16	Della Wyatt	Royalty Interest	$50

STEPHAN R SMITH - P E

Date: 11/9/2012

Consulting Petroleum Engineer
Annual CashFlow - Summary
Grand Totals

Time: 3:23 PM

Date	Well Count	Gross Production Oil (Bbl)	Gross Production Gas (Mcf)	Net Production Oil (Bbl)	Net Production Gas (Mcf)	Average Prices Oil ($/Bbl)	Average Prices Gas ($/Mcf)	Sales Total ($)
12/2012	7	4,203	0	1,890	0	76.91	0.00	145,342
12/2013	7	24,946	0	11,360	0	73.20	0.00	831,539
12/2014	7	23,130	0	10,519	0	69.99	0.00	736,247
12/2015	7	21,484	0	9,760	0	68.62	0.00	669,758
12/2016	7	19,987	0	9,072	0	68.36	0.00	620,188
12/2017	6	17,929	0	8,023	0	68.64	0.00	550,704
12/2018	6	16,322	0	7,239	0	68.64	0.00	496,878
12/2019	5	14,703	0	6,479	0	68.64	0.00	444,708
12/2020	5	13,806	0	6,084	0	68.64	0.00	417,603
12/2021	5	12,967	0	5,715	0	68.64	0.00	392,252
12/2022	5	12,182	0	5,369	0	68.64	0.00	368,532
12/2023	5	11,283	0	4,942	0	68.64	0.00	339,193
12/2024	4	9,803	0	4,137	0	68.64	0.00	283,967
12/2025	4	9,207	0	3,884	0	68.64	0.00	266,586
12/2026	4	8,649	0	3,647	0	68.64	0.00	250,333
Remainder:		77,326	0	30,558	0	68.64	0.00	2,097,481
Grand Total:		297,927	0	128,677	0	69.25	0.00	8,911,308

Date	Operating Expenses ($)	Taxes ($)	Operating Income ($)	Other Costs ($)	Periodic Cash Flow ($)	Cumulative Cash Flow ($)	10% Cash Flow ($)
12/2012	31,433	12,137	101,772	0	101,772	101,772	100,544
12/2013	190,749	70,332	570,457	0	570,457	672,229	533,896
12/2014	195,518	63,035	477,694	0	477,694	1,149,923	406,449
12/2015	200,406	57,955	411,397	0	411,397	1,561,320	318,230
12/2016	205,416	54,165	360,608	0	360,608	1,921,928	253,595
12/2017	181,406	48,352	320,946	0	320,946	2,242,874	205,160
12/2018	166,135	44,040	286,703	0	286,703	2,529,577	166,610
12/2019	145,392	41,180	258,136	0	258,136	2,787,712	136,356
12/2020	145,392	38,670	233,541	0	233,541	3,021,254	112,152
12/2021	145,392	36,322	210,537	0	210,537	3,231,791	91,916
12/2022	145,392	34,126	189,014	0	189,014	3,420,805	75,021
12/2023	138,889	31,409	168,894	0	168,894	3,589,699	60,943
12/2024	106,376	26,295	151,296	0	151,296	3,740,995	49,627
12/2025	106,376	24,686	135,524	0	135,524	3,876,520	40,414
12/2026	106,376	23,181	120,776	0	120,776	3,997,296	32,743
Remainder:	1,153,869	194,227	749,385	0	749,385	4,746,681	122,064
Grand Total:	3,364,514	800,114	4,746,681	0	4,746,681	4,746,681	2,705,720

Discount Present Worth:

0.00 %	4,746,681
10.00 %	2,705,720
20.00 %	1,927,943
30.00 %	1,524,446
40.00 %	1,277,470
50.00 %	1,110,257
60.00 %	989,166
70.00 %	897,171
80.00 %	824,738
90.00 %	766,107
100.00 %	717,591

Economics Information:

Net Payout Date:	11/2012
Rate of Return:	>100 %
Return on Investment:	0.00
Disc Return on Invest:	0.00

Economics Summary:

	Bbl Oil	Mcf Gas
Ultimate Gross	1,029,722	0
Historic Gross	727,672	0
Gross at Eff Date	731,794	0
Remaining Gross	297,927	0
Remaining Net	128,677	0

Economic Dates:

Effective Date	11/2012
Calculated Limit	01/2051
Economic Life	459 Months
	38 Years 3 Months

NORTHWESTERN ENERGY
ACQUISITION OF

NFR ENERGY, MONTANA
PDP - OIL WELLS ONLY

As-of-Date of November 1, 2012

NorthWestern Corporation
d/b/a NorthWestern Energy
40 East Broadway Street
Butte, MT 59701
Telephone: (406) 497-3000
Facsimile: (406) 497-2535
www.northwesternenergy.com

NorthWestern Energy

January 3, 2013

Behm Energy, Inc.
Attn: Lenny Behm
P.O. Box 608
Minot, ND 58701-0608

Re: Bear Paw Oil Sale

Dear Lenny,

On behalf of NorthWestern Corporation d/b/a NorthWestern Energy (the "Company"), we would like to express our appreciation for your interest in exploring the possible acquisition of certain operated and nonoperated oil producing properties in Blaine County, Montana (the "Assets") generally described as follows:

Seven Operated wells
Two Non-Operated wells
Gross Production 2,200 BO/Month
Net Production 1,000 BO/Month
Working Interest range from 40.625% to 81.25%
Net Revenue Interest range from 35.53% to 74.83%
Producing formation is the Sawtooth
Potential upside with additional drilling

We are now writing to invite you to submit a nonbinding bid to acquire the Assets (the "Proposal"). This letter sets forth the procedure and timing with respect to your submission of a Proposal, as well as summarizing the general process which the Company will employ.

You should fill out the attached **Company Information Form** and sign the attached **Confidentiality and Nondisclosure Agreement** to receive a confidential sales information data package (the "Confidential Sales Package"). Return both to:

NorthWestern Energy
Attn: Pat Callahan
40 East Broadway
Butte, MT 59701
Fax: 406-497-3480
Pat.callahan@northwestern.com

The expected timing is:

Offering Date: January 3, 2013
Effective Date of the Sale: January 1, 2013
Bids Due by February 28, 2013

In this phase of the process, the only information about the Assets to be made available will be that contained in the Confidential Sales Package, with clarification, if any, supplied only by us in response to your inquiries. The Company recognizes that the successful bidder will be allowed to conduct detailed due diligence prior to entering into a definitive agreement. At the same time, we intend to conduct the process in a way that will minimize the disruption to the Company and its business.

Your Proposal should be in writing and submitted to us via facsimile, or electronic version by email, or courier, using my contact information listed above, to arrive no later than 5:00 p.m. Mountain time on February 28, 2013.

In order to be able to fully evaluate your Proposal, it should include the following:

- a description of the transaction that you would propose, including the cash consideration, stated in U.S. dollars, that you would be willing to pay for the Assets based on the information received to date;
- the identity of the prospective buyer entity in a potential transaction;
- an indication of the additional information that you would require to complete your due diligence investigation of the Assets, including any specific topics that are of particular significance or documents that you would like to review before submitting a binding proposal;
- a description of any corporate, stockholder, regulatory or other approvals or consents that may be required to consummate a transaction, together with an indication of the timing anticipated in obtaining such approvals or consents, and the commitments you would make with respect to such approvals or consents to ensure a transaction would be consummated expeditiously;
- a description of any material contingencies required to complete a transaction or material conditions on which you are basing your Proposal, and an indication of the anticipated timing when such contingencies or conditions can be satisfied;
- the extent, duration and general terms of any transitional services or supply agreements that you will require as part of any transaction;
- a list of any outside advisors (including your consultants, accountants and outside legal counsel, and investment bank, if any) who you expect to work with on these matters; and
- a list of the names, direct telephone numbers, email addresses, and facsimile numbers of the persons within your organization with whom we may clarify issues with respect to your Proposal.

After evaluating the Proposals, the Company expects to select a successful bidder and to promptly enter into negotiations on a definitive agreement, along with the successful bidder's due diligence activity. In making this determination, we may seek clarification of the information received in some or all of the Proposals. The Company will consider a variety of factors, such as the amount of the bid, the party's financial and operating strength and reputation, and its ability to consummate a transaction in an expeditious manner. Upon selection of the successful bidder, that party will be provided with a proposed form of definitive acquisition agreement specifying the terms and conditions upon which the Company will be willing to enter into the transaction.

The Company reserves the right in its sole and absolute discretion to consider or reject any or all Proposals, and to amend, modify or terminate these procedures at any time without notice and without specifying the reasons therefor. The Company makes no representations or warranties, either express or implied, as to the accuracy or completeness of the information in the Confidential Sales Package, or its suitability for any purpose, and the definitive agreement will contain all representations and warranties relative to the transaction. The sales process contemplated herein is not exclusive. The Company reserves the right to withdraw all or any portion of the Assets or change all or any terms of this sales process at any time without notice to any potential purchaser.

Please do not hesitate to call me at 406-497-2137 with any questions regarding these procedures, the information to be provided in the Proposals, or the process in general. We ask that you, and any of your advisors, not contact anyone at the Company other than me without our prior consent. We appreciate your interest in the Assets and look forward to receiving your Proposal.

Sincerely,

Pat Callahan
Director Gas Growth

NorthWestern Energy

Blaine County, Montana

Oil Properties

Company Information Form

Company Name:_____

Contact Name:_____

Title:_____

Address:_____

City:_____

State:_____

Zip Code:_____

Phone:_____

Fax:_____

E-Mail:_____

Confidentiality and Nondisclosure Agreement

This Confidentiality and Nondisclosure Agreement ("Confidentiality Agreement") is dated this _____ day of _____, 2013, by and between NorthWestern Corporation d/b/a/ NorthWestern Energy, ("NorthWestern"), 40 East Broadway, Butte, MT 59701, and Behm Energy, Inc., P.O. Box 608, Minot, ND 58701-0608 ("Potential Bidder"), with each of NorthWestern and Potential Bidder referred to herein individually as a "Party" and collectively as the "Parties."

WHEREAS, NorthWestern has initiated a process to solicit bids for certain assets it intends to sell ("Bid Process"), and Potential Bidder is interested in a possible bid for such assets, and the Parties desire to share certain information that is proprietary or valuable trade secret information solely for the purpose of such potential transaction ("Potential Transaction"); and

WHEREAS, the Parties wish to prohibit disclosure and use of the Confidential Information by either Party for any purpose other than that stated above,

NOW, THEREFORE, in consideration of the mutual agreements herein contained and other good and valuable consideration, the receipt and sufficiency of which are hereby mutually acknowledged, the Parties agree as follows:

1. Either party (the "Disclosing Party") may disclose to the other party (the "Receiving Party") such Confidential Information as it may choose to disclose. As used in this Confidentiality Agreement, the term "Confidential Information" means any and all information, whether written or oral, whether or not specifically labeled as confidential, that the Disclosing Party provides or has provided to the Receiving Party with respect to the Potential Transaction in accordance with the preceding sentence. Without limiting the generality of the foregoing, Confidential Information shall include all information disclosed by NorthWestern to Potential Bidder in connection with the Bid Process, including the confidential sales information data package to be provided to Potential Bidder upon its execution of this Confidentiality Agreement, and subsequent communications between the Parties with respect thereto, regardless of whether such information was marked "Confidential" as part of the Bid Process.

2. Notwithstanding the above, the Parties agree that information shall not be deemed Confidential Information and the Receiving Party shall have no obligation to hold in confidence such information, where such information:

a. Is already known to the Receiving Party, having been disclosed to the Receiving Party by a third party without such third party having an obligation of confidentiality to the Disclosing Party; or

b. Is or becomes publicly known through no wrongful act of the Receiving Party, its employees, officers, directors, or agents; or

c. Is independently developed by the Receiving Party without reference to any Confidential Information disclosed hereunder; or

d. Is approved for release (and only to the extent so approved) by the Disclosing Party; or

e. Is disclosed pursuant to the lawful requirement of a court or governmental agency or where required by operation of law (as more fully described below in paragraph 5 of this Agreement).

3. All Confidential Information disclosed under this Agreement shall be and remain the property of the Disclosing Party and nothing contained in this Agreement shall be construed as granting or conferring any rights to such Confidential Information on the other Party. The Receiving Party shall accept the Confidential Information for the sole purpose of discussing and investigating the Potential Transaction and will not use the Confidential Information for any other purpose. The Receiving Party may not disclose the Confidential Information to any other person except its employees or representatives, including its consultants, accountants, legal counsel, and investment bankers, but only for purposes of their work on the Potential Transaction, and subject to the terms and conditions herein. The Receiving Party further agrees to inform such employees and representatives of the existence of this Confidentiality Agreement and to instruct such employees and representatives not to disclose the Confidential Information to others. Such employees and representatives are obligated to keep such information in confidence as if they were parties to this Confidentiality Agreement.

4. The Receiving Party shall promptly notify the Disclosing Party of any disclosure of such Confidential Information in violation of this Confidentiality Agreement.

5. The obligation not to disclose or use the Confidential Information shall not apply to information which is required to be disclosed (i) by court order, subpoena or other legal process; (ii) by regulatory agency or regulatory process (including proceedings before the Montana Public Service Commission) or otherwise in connection with an examination of either Party's records by appropriate authorities; or (iii) otherwise as required by law; provided, however, that the Receiving Party shall (a) give the Disclosing Party as much prior notice thereof as is reasonably practicable so that the Disclosing Party may seek such protective orders or other protection as it may elect, at the Disclosing Party's sole cost and expense and (b) reasonably cooperate with the Disclosing Party in protecting the confidential or proprietary nature of the Confidential Information that must be disclosed. Notwithstanding the foregoing, Potential Bidder understands that NorthWestern, as a public utility, is subject to regulation by the Montana Public Service Commission ("MPSC") and that NorthWestern may be required to submit any and all information it receives from Potential Bidder related to the Potential Transaction to the MPSC as part of MPSC regulatory proceedings. It shall be Potential Bidder's responsibility to request a Motion for Protective Order from the MPSC in the event NorthWestern is required to disclose any information to the MPSC related to Potential Bidder or the Potential Transaction, including the Bid Process, for which Potential Bidder desires to seek confidential or trade secret protection. NorthWestern shall provide reasonable support and cooperation to Potential Bidder in seeking such protection. Except as may be required by law, neither Party shall issue any public statements or press releases regarding the Potential Transaction without the prior approval of the other Party, which approval shall not be unreasonably withheld or delayed.

6. The Receiving Party's obligation not to use or disclose the Confidential Information shall continue in effect for a period of two (2) years from the date of this Confidentiality Agreement. Confidential Information that is considered trade secret will remain protected even after expiration of such two years period or termination of this Confidentiality Agreement.

7. All Confidential Information, including any copies, whether paper, electronic, or otherwise and derivatives thereof, shall be returned to the Disclosing Party or destroyed immediately upon termination of this Confidentiality Agreement.

8. The Receiving Party acknowledges that its breach or any breach by the employees or representatives who have access to the Confidential Information pursuant to this Confidentiality Agreement could cause damage to the Disclosing Party which is irreparable and immeasurable in terms of monetary value. For this reason, the Parties agree that this Confidentiality Agreement may be specifically enforced by any court of competent jurisdiction and consent to the entry of such restraining orders and injunctions (and waive the obligation to post any bond in connection therewith) as may be necessary to prevent a breach of this Confidentiality Agreement and to carry out its terms. This remedy may not be exclusive, and the Disclosing Party may have such other and further relief as may be permitted by law, including an award of actual and exemplary damages by a court of competent jurisdiction. No failure or delay by the Disclosing Party in exercising any right, power, or privilege hereunder shall operate as a waiver thereof, nor shall any single or partial exercise thereof preclude any other or further exercise thereof or the exercise of any right, power, or privilege hereunder.

9. This Confidentiality Agreement shall be governed by and construed under the laws of the State of Montana.

10. This Confidentiality Agreement constitutes the entire agreement between the Parties hereto concerning the subject matter hereof and may not be modified except in writing signed by a duly authorized representative of each Party. This Confidentiality Agreement shall be binding upon and inure to the benefit of the successors and assigns of the Parties hereto. This Confidentiality Agreement may not be assigned by either Party hereto without the express written consent of the other Party. Nothing in this Confidentiality Agreement shall be construed to constitute an agency, partnership, joint venture, or other similar relationship between the Parties.

11. IN WITNESS WHEREOF, the Parties have caused this Confidentiality Agreement to be executed by their duly authorized representatives as of the date first above written.

Behm Energy, Inc.	**NorthWestern Corporation d/b/a NorthWestern Energy**
_____	_____
By: _____	By: _____
Its: _____	Its: _____

Asset Review

Executive Summary

The NorthWestern Energy (NWE) had an evaluation of oil interests owned in Blaine County, Montana prepared by Stephan R. Smith. Proved net reserves are estimated to be 128.7 MBO as of November 1, 2012. Combined with the proved undeveloped, probable and possible estimated reserves of 1,352.3 MBO the PV10 is estimated at $22.7 million. NWE is offering these oil assets in a single package.

Production

The producing assets are located in the Bearpaw Arch located in Blaine County, in north central Montana. Seven of the wells are operated by NWE and two by Behm Energy Incorporated. Working interests range from 46.625% to 81.25% and average 65.17% while the net revenue interest range from 35.53% to 74.83% and averages 54.8%.

There are a total of nine Proved Developed Producing wells in the package. The gross production for October 2012 was 2,205 BO (1,007 BO net).

NET RESERVE SUMMARY & PRESENT VALUE AT 10%		
RESERVE CATEGORIES	**OIL (MBO)**	**PV10 ($M)**
PRODUCTION		
PDP	128.7	2.7
PDNP	0	0
PUD	567	8.82
TOTAL PROVED	706	11.52
PROB	588	8.39
POSS	197	2.84
TOTAL UNPROVED	785	11.23
TOTAL	1,481	22.75
Effective Date: November 1, 2012		

The package includes 24 projected completions,the average Sawtooth completion has a PV10 value of $835K.

ECONOMICS BY RESERVOIR										
Reservoir	Reservoir Category	Well Count	Net Capital Investment (MS)	Gross Reserves		Net Reserves		Future Net Revenue Disc @ 10% (MS)	Percent of Total (%)	
				OIL (MBO)	GAS (MCF)	OIL (MBO)	GAS (MCF)			
Sawtooth										
	PDP	9	0	298	0	129	0	2,703	11.89%	
	PDNP	0	0	0	0	0	0	0	0.00%	
	PUD	12	3,762	1,440	0	567	0	8,815	38.75%	
	PRB	9	3,896	1,080	0	588	0	8,385	36.86%	
	POS	3	1,225	360	0	197	0	2,844	12.50%	
	TOTAL	33	8,883	3,178	0	1,481	0	22,750	100%	

Evaluation Pricing

FUTURE PRODUCT PRICES							
Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**Thereafter**
$/BBL	$76.91	$73.29	$69.99	$68.64	$68.64	$68.64	Held flat for the Economic Life

The assumed forward average oil price for 2013 is $73.29/BBL and decreases to $68.64/BBL in 2015. The price is held flat for the remainder of the well life. The average sale price in November 2012 was $70.975/BBL with a high of $72.47 and a low of $70.12/B.

Sawtooth

In north-central Montana the Jurassic Sawtooth Formation unconformably overlies the Mississippian Madison Group. This unconformity represents approximately 150 million years of missing section. Regionally, the formation consists of three members; the Tampico, the Firemoon and the Bowes.

The Sawtooth is oil productive at a number of fields in Montana and Saskatchewan, including Rabbit Hills, Battle Creek and Bowes Fields. The primary oil reservoir is found as a stratigraphic high porosity coquina at the top of the formation. Thus the traps are commonly combination structural-stratigraphic in nature. The productive unit has thickness up to approximately 30 feet. Porosity can be as high as 27% with permeability ranging from 1 to 500 md. Initial Potentials are usually 10 to 250 BOPD with EUR's of 25 to 1,000 MBOE.

The Sawtooth Reservoir is the only oil reservoir in the area. Lasser reports 94 wells have been completed in the Sawtooth with first production occurring in 1986. These wells have cumulative production of 5.7 MMBO and 18.4 MMBW over the past 25 years. There are currently 52 active wells located in 5 fields; Weygand Field, Rabbit Hills Field, Battle Creek Field, Thirty Mile Field and Bowes Field.

Field Name	Cumulative Production		Well Count		First Production
	Oil, BBL	Water, BBL	Total	Active	
Thirty Mile	14,246	5,214	2	2	1986
Battle Creek	139,043	7,628	2	2	2003
Weygand	297,208	43,183	4	3	1986
Rabbit Hills	2,539,481	4,630,175	17	15	1986
Bowes	2,686,562	13,723,301	69	30	1986
Total	**5,678,140**	**18,409,401**	**94**	**52**	

NWE has ownership in 9 active wells located in Weygand Field (3), Rabbit Hills Field (2), Battle Creek Field (2) and Thirty Mile Field (2). The typical Sawtooth well comes online at 615 BOPM, and declines exponentially at 5%. On average, the projected EUR for these wells is 120 MBO over a 35-year life. NWE estimates the capital cost associated with drilling and completing Sawtooth well to be $700,000.

Proved Developed Non-Producing Reserves (PDNP)

NWE has identified no PDNP opportunities in the Sawtooth.

Proved Un-Developed (PUD)

A previous owner identified 12 proved un-developed drilling opportunities in the Sawtooth reservoir. Net reserves of 567 MBO and a PV10 of $8.82 million.

Probable (PRB)

A previous owner identified 9 probable drilling opportunities in the Sawtooth reservoir. Net reserves of 588 MBO and a PV10 of $8.39 million.

Possible (POS)

A previous owner identified 3 possible drilling opportunities in the Sawtooth reservoir. Net reserves of 197 MBO and a PV10 of $2.84 million.

Exhibit__(PEC-26) has been provided only on the attached CD.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF STEPHAN R. SMITH, PE

ON BEHALF OF NORTHWESTERN ENERGY

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Description	Starting Page No.
Witness Information	2
Purpose of Testimony	3
Bear Paw (NFR) Evaluation	5
South Bear Paw (Devon) Evaluation	8
Bear Paw (NFR) Oil Evaluation	9

Exhibits

Bear Paw (NFR) Acquisition Evaluation	Exhibit__(SRS-1)*
South Bear Paw (Devon) Acquisition Evaluation	Exhibit__(SRS-2)*
Bear Paw (NFR) Oil Acquisition Evaluation	Exhibit__(SRS-3)*
Client Brochure	Exhibit__(SRS-4)

* Exhibits on attached CD.

1 **Witness Information**

2 **Q. What is your name and business address?**

3 **A.** I am Stephan R. Smith and my business address is 2454 Tavern Way,

4 Castle Rock, Colorado 80104.

5

6 **Q. What education do you have to qualify you to offer the expert**

7 **opinions in your testimony?**

8 **A.** I have a Professional Degree (which is similar to a Bachelor of

9 Science Degree), Petroleum Engineering from the Colorado School of

10 Mines, granted in July, 1969.

11

12 **Q. What professional experience do you have to qualify you to offer**

13 **the expert opinions in your testimony?**

14 **A.** I am a Registered Professional Engineer, Petroleum, in the state of

15 Colorado, #24924, and a Registered Professional Engineer,

16 Petroleum in the state of Wyoming, #5438 (retired). My client

17 brochure is attached as Exhibit__(SRS-4).

18

19 **Q. Have you testified before the Montana Public Service**

20 **Commission?**

21 **A.** No.

22

23 **Q. Have you testified before any Montana regulatory body?**

1 **A.** No. I was told by Tom Richmond, Division Administrator and
2 Petroleum Engineer, Montana Board of Oil and Gas, that my PE
3 registration in Colorado and Wyoming would be sufficient to allow me
4 to present expert testimony before the Montana Board of Oil and Gas.
5
6 **Q. Have you testified in other jurisdictions regarding the estimation**
7 **and determination of natural gas reserves?**
8 **A.** Yes. I have testified on numerous occasions over the past 36 years
9 before the Wyoming Oil and Gas Conservation Commission, the
10 Colorado Oil and Gas Conservation Commission, the Nebraska Oil
11 and Gas Conservation Commission, and the Utah Division of Oil, Gas,
12 and Mining regarding oil and gas reserve determination and oil and
13 gas well spacing and drainage.
14
15 **Purpose of Testimony**
16 **Q. What is the purpose of your testimony?**
17 **A.** My testimony addresses the following:
18 • Key findings from the reserves report I prepared for NorthWestern
19 Energy ("NorthWestern") on the NFR Energy LLC Montana
20 Properties ("Bear Paw (NFR)"). The report is dated March 29,
21 2012 and it discusses the estimated Proved Developed Producing
22 Reserves and income forecast for Bear Paw (NFR) as of January

1, 2012 as well as an acquisition evaluation at year end 2011. It is attached as Exhibit__(SRS-1) (provided on CD).

- Key findings from the reserves report I prepared for NorthWestern on the DEVON Energy Co. LP Montana Properties ("South Bear Paw (Devon)"). The report is dated November 6, 2012 and it discusses the estimated Proved Developed Producing Reserves and income forecast for South Bear Paw (Devon) as of January 1, 2013 as well as an acquisition evaluation at year end 2012. It is attached as Exhibit__(SRS-2) (provided on CD).
- Key findings from the reserves report I prepared for NorthWestern on the Bear Paw (NFR) Oil Properties ("Bear Paw (NFR) Oil"). The report is dated November 12, 2012 and it discusses the estimated Proved Developed Producing Reserves and income forecast for Bear Paw (NFR) Oil wells as of November 1, 2012 as well as an acquisition evaluation at November 1, 2012. It is attached as Exhibit__(SRS-3) (provided on CD).

Q. What does "Proved Developed Producing Reserves" mean?

A. "Proved Developed Producing Reserves" are those natural gas reserves and crude oil reserves that can be produced economically from existing production and compression facilities.

Bear Paw (NFR) Evaluation

Q. How did you calculate the Proved Developed Producing Reserves for Bear Paw (NFR)?

A. Historical production from each well was obtained from the following sources: 1) The Montana Board of Oil and Gas Conservation website, a public source for oil and gas production by well; 2) IHS Global Inc., a commercial public source for oil and gas production by well; and 3) Lasserdata.com, the website of Lasser Inc., also a commercial public source for oil and gas production by well.

Historical decline curves (log plot of production versus time) were then developed for each well, using PowerTools®, a commercially available economic and plotting software which is discussed in more detail below. The historical decline curves were projected into the future, developing, on a monthly basis, estimated gross and net oil and natural gas production. The net natural gas income was then determined by multiplying net oil and gas production by the oil and gas price forecasts (as outlined in each report, using both AECO and NYMEX price decks). Working interest lease operating expenses and net production taxes were deducted from net oil and natural gas income to generate net profit on a monthly basis. When monthly net profit went negative for a particular well, the computer software stopped the production projection for that well. Adding all of the

positive monthly production values generated Proved Developed Producing Reserves for each well. All of the individual well reserves were then totaled to produce the Project Total Proved Developed Producing Reserves.

Q. Why is the decline curve analysis the best method for calculating Proved Developed Producing Reserves?

A. Decline curve analysis makes the best use of historical reservoir performance, historical mechanical performance, and historical climate performance. Decline curve analysis is the best reserve determination method available to incorporate reservoir rock, reservoir fluid, and pressure properties into predicting future performance, therefore determining an accurate estimate of Proved Developed Producing Reserves.

Q. Is decline curve analysis commonly used to calculate Proved Developed Producing Reserves in the natural gas industry?

A. Yes.

Q. What other methods could you have used to calculate the Proved Developed Producing Reserves?

A. One alternative method is to perform a volumetric calculation of gas-in-place and then apply a recovery factor to estimate producing

reserves. Another method is type curve analysis whereby performance of offset wells with similar rock properties is used to estimate producing reserves.

Q. Why are those methods inferior to the method that you used?

A. They are not as accurate. The further removed the reserve estimation procedure is from decline curve analysis, the greater the uncertainty that wells will produce as predicted. There is a much greater uncertainty in the parameters that are used in volumetric or type curve analysis than in historical production decline curve analysis.

Q. What software product did you use to perform these calculations?

A. I used PowerTools®, a commercially available software package offered by IHS Global that imports historical monthly production data, develops historical decline curves, projects production into the future, and calculates future income, expenses, and profit.

Q. What did you calculate to be the Proved Developed Producing Reserves for the Bear Paw (NFR) acquisition?

A. Using the AECO price deck contained in my reserve report, remaining Proved Developed Producing Reserves were estimated at 13.4 billion cubic feet ("Bcf").

1 **Q. What is the probability that the actual Proved Developed**
2 **Producing Reserves is less than the amount you calculated?**
3 **A.** I would estimate the probability at less than 10%. There is an equal
4 probability that reserves will be higher than calculated.
5
6 **Q. In your acquisition evaluation, you reported different Net Gas**
7 **Reserves for AECO and NYMEX. Why is there a difference?**
8 **A.** Net Gas Reserves is dependent on when wells reach economic limit.
9 The NYMEX price deck is slightly higher than the AECO price deck.
10 Because of this higher price, the model predicts that the wells would
11 produce longer using the NYMEX price deck; therefore it shows more
12 recoverable reserves.
13
14 **South Bear Paw (Devon) Evaluation**
15 **Q. How did you calculate the Proved Developed Producing Reserves**
16 **for South Bear Paw (Devon)?**
17 **A.** I followed the identical steps described above to perform a historical
18 production decline curve analysis. However, for this evaluation, I
19 used only the AECO 2012-09-12 price deck to calculate the net
20 natural gas income rather than both AECO and NYMEX price decks.
21
22 **Q. What did you calculate the Proved Developed Producing Reserves**
23 **to be for the South Bear Paw (Devon) acquisition?**

1 **A.** Using the AECO price deck contained in my reserve report, remaining
2 Proved Developed Producing Reserves were estimated at 64.586 Bcf.
3
4 **Q. What is the probability that the actual Proved Developed**
5 **Producing Reserves is less than the amount you calculated?**
6 **A.** As with the Bear Paw (NFR) acquisition, I would estimate the probability
7 at less than 10%. And again, there is an equal probability that reserves
8 will be higher than calculated.
9
10 **Bear Paw (NFR) Oil Evaluation**
11 **Q. How did you calculate the Proved Developed Producing Reserves**
12 **for Bear Paw (NFR) Oil?**
13 **A.** I followed the identical steps described above to perform a historical
14 production decline curve analysis. The net crude oil income was
15 determined by multiplying net oil production by the oil price deck
16 contained in the report.
17
18 **Q. What did you calculate the Proved Developed Producing Reserves**
19 **to be for the Bear Paw (NFR) Oil acquisition?**
20 **A.** Using the crude oil price deck (provided by NorthWestern) contained in
21 my reserve report, remaining Proved Developed Producing Reserves
22 were estimated at 128,677 barrels (bbls) of oil.
23

1 **Q. What is the probability that the actual Proved Developed**

2 **Producing Reserves is less than the amount you calculated?**

3 **A.** As with the two natural gas acquisitions discussed above, I would

4 estimate the probability at less than 10%. And again, there is an

5 equal probability that reserves will be higher than calculated.

6

7 **Q. Does this conclude your testimony?**

8 **A.** Yes, it does.

Because together they are voluminous, the following exhibits have been provided only on the attached CD:

Exhibit__(SRS-1)

Exhibit__(SRS-2)

Exhibit__(SRS-3)

STEPHAN SMITH PE, LLC

CONSULTING PETROLEUM ENGINEER

CLIENT

BROCHURE

2454 TAVERN WAY
Castle Rock, Colorado 80104
Office: (720) 359-0481

e-mail: STEVE@SRS-PE.COM

9/2016

STEPHAN SMITH PE, LLC

Consulting Petroleum Engineer

Office: 720-359-0481 **2454 TAVERN WAY** **E-Mail STEVE@SRS-PE.COM**
Castle Rock, CO 80104

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STEPHAN SMITH PE, LLC

Consulting Petroleum Engineer

Office: 720-359-0481 **2454 TAVERN WAY** **E-Mail STEVE@SRS-PE.COM**
Castle Rock, CO 80104

"It is unlawful for any individual to hold himself or herself out to the public in the state of Colorado as a professional engineer unless said individual is duly registered and licensed in the state of Colorado "
Colorado State Board of Registration for Professional Engineers and Professional Land Surveyors

STEPHAN R SMITH is a **REGISTERED PROFESSIONAL ENGINEER** providing **PETROLEUM ENGINEERING CONSULTING SERVICES** to the United States Oil and Gas Industry.

"My continuing goal is to provide a very high level of Petroleum Engineering expertise but at a competitive industry rate."

SERVICES OFFERED

Drilling and Completion Supervision, Plan and AFE Development and Implementation

Coal Gas Evaluations, Reserves and Performance:
Powder River Basin – Wyoming; **Piceance Basin** - Colorado; **Raton Basin** – Colorado
Sand Wash Basin – Colorado and Wyoming; **San Juan Basin** - Colorado and New Mexico;
Uinta Basin – Utah

Petroleum Engineering for Property Acquisitions and Dispositions.

Petroleum Engineering on Special Projects and Operational Well Problems.

On-the-job Petroleum Engineering for Those Burdened with Lean Staffs.

Recoverable Reserve Reports for SEC, Investors, Internal and Coordination with Lending Institutions.

Engineering and Implementation of Secondary Floods and Equity Formula Determination

Expert Witness Testimony before the Colorado and Wyoming Oil and Gas Conservation Commissions.

Due-Diligence Studies for Drilling and Oil and Gas Income Programs.

QUALIFICATIONS

45 years experience working with Major and Independent Oil and Gas Companies.
(28 years Independent Petroleum Engineering Consultant)
(17 years as on-staff Petroleum Engineer)

Registered Professional Engineer (Petroleum) - Colorado (#24924) and Wyoming (#5438)

Full Membership - Society of Petroleum Engineers of AIME

Undergraduate Degree: Petroleum Engineer, Colorado School of Mines, Golden, Colorado
Minor in Mathematics, Graduated July 19, 1969

Continuing Graduate Work: Colorado School of Mines, Golden, Colorado, 1997-2008

FOR ADDITIONAL INFORMATION PLEASE CALL or E-MAIL. THANK YOU !!

STEPHAN SMITH PE, LLC

Consulting Petroleum Engineer

Office: 720-359-0481 | 2454 TAVERN WAY Castle Rock, CO 80104 | E-Mail STEVE@SRS-PE.COM

HISTORICAL CLIENT LIST

Advantage Resources, Inc.	Fidelity Exploration & Production	Petrogulf Corporation
Aexco Petroleum, Inc.	FMC Corporation	Petroleum Energy Corporation
Allen Oil and Gas Co.	Focus Energy, LLC	Phillips Petroleum +C2:C39Company
American Acquisitions Corporation	Forest Oil Corporation	Pillar Consultants, Inc.
Anderson Oil Company	Four Ten Exploration	Pioneer Resources
Arapahoe Petroleum	Freedman, Martin	Pollard, Gore & Harrison
Audrey Foster Trust	Freeman, Joe	Powder River Basin Gas Corporation
Ashby Drilling	Fuel Resources, Inc.	Powers Energy, Inc.
Azalea Oil Company	Gadeco, LLC	Presco, Inc.
Bank of Oklahoma	G & H Production Company	Questar Oil and Gas Company
Bates, Edward	Hanks, Peter	Remuda Corporation
Bauer Pipeline Company, LLC	Independent Production Company, Inc.	Resource Services International
Bellaire Oil Co.	Intoil	Resource Technology Corporation
B H Energy, LLC	J. M. Huber Corporation	Richardson Oil Company
Black Buttes Partners	Jubilant Energy, India	Rock Creek Resources LLC
Black Coral LLC	Karen Griscom / Brian Boyd - Gramps	RTM Partnership
Bearpaw Energy	Kastner Land Services, LLC	Ryex Company
Black Diamond Energy, LLC	Kestrel Energy, Inc.	Security Resources
Brabant Petroleum, USA, Company	King, Walter A. - PE	Sheridan Energy, Inc.
Buckland Petroleum, Inc.	Klabzuba Oil and Gas	Smith, Marlis E. Inc.
Buffington, John W., Inc.	Larne Holdings	Smith, Marlis Trust
Canterra Natural Gas, Inc.	Liberty Petroleum, Inc.	Smithco Properties, Inc.
Casear Oil Company	Lion Oil Company, LLC.	Soccoro Properties, LLC
Celsius Energy Company	Magnolia Oil Company	Source Energy, LLC
Chambers, Dansky & Mulvahill, LLC	Marmik Oil Company	South Coast Oil Corporation
Chase Petroleum, LTD	Maxim Drilling	Southern Century, Inc.
Chase-American Production Fund, LTD	McVey Energy Company	Sovereign Energy, LLC
Chesapeake Operating Company	Medallion Petroleum, Inc.	Spencer, Russell A. & Company
Chorney & Associates, LLC	Medallion Production Company	Swift Energy Company
Colorado-American Oil Company	Meritage Energy Partners, LLC	Tiffany, Debra
Consolidated Oil & Gas	Messinger, Paul & Company	Twin Bridges, LLC
Cook, Herb	Minnoco, Inc.	Universal Resources Corporation
Crestone Energy Ventures, LLC	Morenergy Exploration Company	V. H. J. Energy
Davis Oil Company	Morgan-Richardson Operating Company	Vista Energy, LLC
Davis Petroleum Corporation	Morse Acquisitions	Vondrehle. William F.
Derby, Inc	Mountain Pacific General, Inc.	Voyager Exploration, Inc.
Diversified Operating Company	Mueller Energy, LLC	Western American Resources LLC
Diversified Resources	M & G Drilling, Inc.	Western Gas Processors
Eagle Exploration	Natural Gas Ventures	Westpath, South, LTD
EnCana Oil and Gas (USA), Inc.	Newtech Global	Westport Oil & Gas Company
Energy Investors 1988 LTD Partnership	Nielson & Associates	Wilbanks Exploration, Inc.
Entek GRB	Northwestern Energy	Willischild Oil & Gas Corp.
Evergreen Resources, Inc.	P & M Petroleum Management	Willsource Enterprises
Executive Petroleum Services, LLC	Panther Creek Resources, LLC	Wind River Resources Corporation
Farmers Energy Corporation	Paragon Petroleum	Windmill Energy Services, LLC
Federated Oil and Gas	Peak Energy Resources, Inc.	88th & Tower

STEPHAN SMITH PE, LLC

Consulting Petroleum Engineer

Office: 720-359-0481 | 2454 TAVERN WAY Castle Rock, CO 80104 | E-Mail STEVE@SRS-PE.COM

CAREER SUMMARY

Forty five years + experience in Reservoir Engineering, Production Engineering and Drilling covering:

* Drilling and Completion supervision, drill plan and AFE development and implementation.
* Supervised drilling and/or completion and recompletions activities in Nebraska, New Mexico, Wyoming, Utah, North Dakota, Colorado, and Texas.
* Supervised on-site well completions, Drill Stem Testing, open hole and cased hole well logging, running surface and production casing, fracture treating, and perforating.
* Coal gas evaluations, reserves and performance: Powder River Basin - Wyoming; Piceance Basin - Colorado; Raton Basin – Colorado; San Juan Basin - Colorado and New Mexico; Sand Wash Basin – Colorado and Wyoming; Uinta Basin - Utah
* Black oil simulation using PC-Boast : Minnelusa, Leo, D Sand, Dakota, Virgil and Missouri formations, predicting primary and secondary oil recovery.
* Unit and equity negotiations, secondary recovery and pressure maintenance units, Colorado, Kansas and Wyoming.
* Implement, modify, and monitor secondary recovery water floods, gas re-pressuring projects, and gas storage projects.
* Federal Exploratory Unit Management and Participating Area Applications.
* Spacing, Water Flood, Water disposal, and Unit Applications before the Wyoming, Colorado, Montana, North Dakota, and Utah Oil and Gas Commissions.
* All types of economic evaluations for bank loan determinations, partner evaluations, outside audits, and and internal use for project ranking and implementation.
* Reservoir and field studies with reports and recommendations, deliverability workups by reservoir and well.
* Pressure test design and analysis including Drill Stem Tests, Buildups, Drawdowns, Reservoir limits and Interference testing.

* Property Acquisitions and Dispositions ($1.5 Billion):
  - 1981 - Davis Oil to Home Petroleum ($690 MM)
  - 1985 - Davis Oil to Apache Corporation ($180 MM)
  - 1986 - Davis Oil and Apache jointly acquired Midcon, Texoma and Cotton Petroleum ($440 MM)
  - 1987 - Davis Oil to Clement Energy ($24 MM)
  - 1988 - Davis Oil to Quinoco ($3.2 MM)
  - 1989 - Chris Craft to American Acquisition $0.1 MM)
  - 1990 - 1993 - Numerous packages for various Consulting Clients
  - 1994 - Presidio to Richardson Operating Company ($10.2 MM)
  - 1996 - Colorado Coal Gas Project ($29.5MM)
  - 1997 – 2013 Numerous Acquisition Projects for Several Clients

GEOGRAPHIC AREAS OF EXPERTISE

Rocky Mountains - Colorado, Utah, Wyoming, Montana, North Dakota, Nebraska & New Mexico;
Gulf Coast - Louisiana, Texas and Mississippi; Anadarko Basin - Texas, Oklahoma and Kansas;
Others - West Virginia, Michigan, West Texas, Offshore Louisiana and Offshore Greece

EXPERIENCE AND ACCOMPLISHMENTS

12/94 - Current: **CONSULTING PETROLEUM ENGINEER** - (Denver, Colorado), consulting for oil and gas industry throughout the United States. Petroleum reservoir evaluations and studies, production and enhanced recovery engineering and economics. Property acquisitions and dispositions. Reserve reporting; SEC, banks, and internal. Colorado and Wyoming Oil and Gas Commission testimony. Supervise daily drilling, completion and production operations.

6/93 - 11/94: **RICHARDSON OPERATING COMPANY** - (Denver, Colorado) *Manager, Production and Engineering*. In charge of daily operations and maintenance of 270 operated wells, drilling new wells and reworking existing wells.. Maintained company reserves for internal and bank use. Property acquisitions and dispositions.

6/87 - 5/93: **CONSULTING PETROLEUM ENGINEER** - (Denver, Colorado), consulting for oil and gas industry throughout the United States. Petroleum reservoir evaluations and studies, production and enhanced recovery engineering and economics. Property acquisitions and dispositions. Reserve reporting, SEC, banks, and internal. Colorado and Wyoming Oil and Gas Commission testimony.

4/81 - 5/87: **DAVIS OIL COMPANY** - (Denver, Colorado) *Chief Engineer*. Field development and drilling and planning. In charge of company reservoir engineering work and reserve reporting (investors, internal, banks). Directed engineering operations on numerous company projects including field development, drilling, waterflood projects, acquisitions and dispositions, and company reserves.

7/79 - 3/81: **DAVIS OIL COMPANY** - (Denver, Colorado) *Reservoir Engineer* Engineering and geological work on company wide properties, specifically gas fields and water floods.

7/75 - 6/79: **MOUNTAIN FUEL SUPPLY COMPANY** - (Salt Lake City, Utah) *Senior Reservoir Engineer* Reservoir evaluations, reserve determinations, and well log analysis. Developed computer simulation model to predict pipeline and reservoir performance.

7/73 - 6/75: **NORTHERN NATURAL GAS COMPANY** - (Omaha, Nebraska) *Reservoir Engineer* Reservoir engineering and reserve determination for existing wells and new wells connected to NNG's pipeline system.

1/72 - 6/73: **MOUNTAIN FUEL SUPPLY COMPANY** - (Rock Springs, Wyoming) *Reservoir Engineer* Reservoir and production engineering on company properties in the Rocky Mountain Area. On-site supervision of well completions, DST's, logging and perforating.

2/70 - 11/71: **MILITARY SERVICE** - (Stateside: Washington and Oklahoma, Overseas: Vietnam) Achieved rank of Specialist 5. Six medals including Bronze Star for Merit. HONORABLE DISCHARGE.

8/69 - 1/70: **MOUNTAIN FUEL SUPPLY COMPANY** - (Rock Springs, Wyoming) *Reservoir Engineer* Reservoir and production engineering on company properties in the Rocky Mountain Area. On-site supervision of well completions, DST's, logging and perforating.

PROFESSIONAL ENGINEERING LICENSES and AFFILIATIONS

Registered Professional Engineer (Petroleum): Colorado (#24924) and Wyoming (#5438 retired)
Full Member: Society of Petroleum Engineers of AIME.

EDUCATION

Undergraduate Degree: Petroleum Engineer, Colorado School of Mines, Golden, Colorado,
Minor in Mathematics. Graduated July 19, 1969

Continuing Graduate Work : Colorado School of Mines, Golden, Colorado - 1997-2008

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF THOMAS K. HOHN, PE

ON BEHALF OF NORTHWESTERN ENERGY

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Exhibits

Hohn Resume	Exhibit__(TKH-1)
Black Hills E&P Evaluation Volume 1	Exhibit__(TKH-2-1)*
Black Hills E&P Evaluation Volume 2	Exhibit__(TKH-2-2)*

* Exhibits on attached CD.

1 **Witness Information**

2 **Q. What is your name and business address?**

3 **A.** I am Thomas K. Hohn and my business address is 2708 First Ave N.

4 Suite 200, Billings, MT 59101.

5

6 **Q. What education do you have to qualify you to offer the expert**

7 **opinions in your testimony?**

8 **A.** I have a Bachelor of Science Degree in Petroleum Engineering from

9 Montana Tech, granted in June 1974.

10

11 **Q. What professional experience do you have to qualify you to offer**

12 **the expert opinions in your testimony?**

13 **A.** I am a Registered Professional Engineer, Petroleum, in the states of

14 Montana, 4303PE; Wyoming, PE 12212; North Dakota, PE 5886; and

15 Oklahoma, PE14085. I have 42 years of experience working as a

16 petroleum engineer in the industry: Unocal July 1974 to January 1978;

17 Petro Lewis Corporation February 1978 to August 1984; Self

18 Employed Petroleum Engineering Consultant, Hohn Engineering,

19 PLLC August 1984 to present. Exhibit__(TKH-1) provides additional

20 detail concerning my professional experience.

21

22 **Q. Have you testified before the Montana Public Service**

23 **Commission?**

1 **A.** No.

2

3 **Q. Have you testified before any Montana regulatory body?**

4 **A.** Yes, I have testified numerous times before the Montana Board of Oil

5 and Gas Conservation.

6

7 **Q. Have you testified in other states regarding the estimation and**

8 **determination of natural gas reserves?**

9 **A.** Yes. In addition to testimony before the Montana Board of Oil and

10 Gas Conservation, I have testified on numerous occasions before the

11 Wyoming Oil and Gas Conservation Commission, Oklahoma

12 Corporation Commission, the North Dakota Industrial Commission,

13 and the Utah Division of Oil, Gas, and Mining regarding oil and gas

14 reserve determination and oil and gas well spacing and drainage.

15

16 **Purpose of Testimony**

17 **Q. What is the purpose of your testimony?**

18 **A.** My testimony addresses the following:

19 • Key findings from the reserves report I prepared for NorthWestern

20 Energy ("NorthWestern") on the Black Hills Exploration and

21 Production Inc.'s ("Black Hills E&P") Properties. The report is

22 dated August 3, 2015, and it discusses the estimated Proved

23 Developed Producing Reserves and income forecast for Black

Hills E&P as of June 1, 2015. The report is divided into two volumes, Exhibit__(TKH-2-1) and Exhibit__(TKH-2-2). Because it is voluminous, it has been provided on CD.

Black Hills E&P Proved Developed Producing Reserves

Q. What does "Proved Developed Producing Reserves" mean?

A. "Proved Developed Producing Reserves" are those natural gas and crude oil reserves that can be produced economically from existing production and compression facilities, with continuation of current operating practices.

Q. How did you calculate the Proved Developed Producing Reserves for Black Hills E&P?

A. Historical production from each well was obtained from the following sources: 1) The Montana Board of Oil and Gas Conservation website, a public source for oil and gas production by well; and 2) IHS Global Inc., a commercial public source for oil and gas production by well. Historical decline curves (semi log plot of production versus time) were then developed for each well using PowerTools®, a commercially available economic and plotting software which is discussed in more detail below.

The historical decline curves define production rate trends that can be projected into the future, which generates an estimate of monthly gross and net oil and natural gas production volumes. The net income from the production streams is calculated by multiplying net oil and gas production by the oil and gas price forecasts (as outlined in the reserve report, using price decks as provided by NorthWestern). Working interest lease operating expenses (also provided by NorthWestern) and net production taxes were deducted from the net production income stream to generate net profit on a monthly basis. When monthly operating expenses exceed the net production revenue of a particular well, the computer software terminates the production projection for that well. The program sums the positive monthly production values which results in the Proved Developed Producing Reserves for each well. All of the individual well reserve forecasts were summed to yield the Project Total Proved Developed Producing Reserves.

Q. Why is the decline curve analysis the best method for calculating Proved Developed Producing Reserves?

A. Decline curve analysis makes the best use of historical reservoir performance, as well as historical operating conditions and practices. Decline curve analysis is the best method available to incorporate reservoir rock, reservoir fluid, and pressure properties into predicting

1 future performance with readily available data. The analysis results in
2 a very reliable estimate of Proved Developed Producing Reserves.
3
4 **Q. Is decline curve analysis commonly used to calculate Proved**
5 **Developed Producing Reserves in the natural gas industry?**
6 **A.** Yes, it is used broadly across the industry and is viewed as a very
7 reliable technique for estimating reserves, especially where significant
8 production history is available, as is the case with the wells included in
9 the Black Hills E&P acquisition.
10
11 **Q. What other methods could you have used to calculate the Proved**
12 **Developed Producing Reserves?**
13 **A.** One alternative method is to perform a volumetric calculation of gas-
14 in-place and then apply an estimated recovery factor to estimate
15 producing reserves. A second alternative method is a material
16 balance analysis which incorporates the reservoir pressure decline
17 with the extraction of the hydrocarbon volumes. Ultimate reserves
18 can then be estimated by assuming an abandonment reservoir
19 pressure, which is the lowest pressure the reservoir can be drawn
20 down to, and at that point no additional hydrocarbons can be
21 economically recovered.
22
23 **Q. Why are those methods inferior to the method that you used?**

1 **A.** For reasonable results, both techniques require more data than is
2 typically available on properties like the Black Hills E&P Properties.
3 While both techniques address the ultimate volumes of reserves, they
4 do not address the time to recover nor the economic value of those
5 reserves. Timing of production requires incorporation of the decline
6 curve analysis to fully estimate the economic reserves and their value.
7
8 **Q. What software product did you use to perform your reserve**
9 **calculations?**
10 **A.** I used PowerTools®, a commercially available software package
11 offered by IHS Global Inc. that imports historical monthly production
12 data, develops historical decline curves, projects production into the
13 future, and calculates future income, expenses, and profit.
14
15 **Q. What did you calculate to be the Proved Developed Producing**
16 **Reserves for the Black Hills E&P acquisition?**
17 **A.** As described in my reserve report, remaining Net Proved Developed
18 Producing Reserves were estimated at 1.2 billion cubic feet of gas
19 and 4,357 barrels of oil.
20
21 **Q. What is the probability that the actual Proved Developed**
22 **Producing Reserves is less than the amount you calculated?**

1 **A.** I would estimate the probability at less than 10%. There is an equal

2 probability that reserves will be higher than calculated.

3

4 **Q. Does this conclude your testimony?**

5 **A.** Yes, it does.

HOHN ENGINEERING, PLLC
2708 1st Avenue North, Suite 200
Billings, MT 59101
406-655-3381 Fax 406-655-3383 Email: hohneng@hohneng.com

Professional Resume of Thomas K. Hohn, P.E.

BUSINESS EXPERIENCE

August 1984 - Present: **Independent Petroleum Engineer Consultant**

Work with various clients on virtually all aspects of technical, business, and management matters. Project highlights include:

- Oil and gas property acquisitions evaluation, negotiation, and assimilation of developed and undeveloped properties. Assisted in property disposition projects, preparation of sales brochures, organization of data rooms, and worked with perspective buyers.

- Expert testimony concerning property valuation, reservoir engineering, and operational matters for regulatory hearings as well as litigation.

- Property evaluation and appraisals for banks, estates, and financial reporting.

- Management and supervision of drilling and completion operations for multi-well drilling programs in Northern Rocky Mountain shallow gas fields. Drilled and completed in excess of 700 wells over last 20 years. Responsibilities included writing bid specifications for services, solicitation and evaluation of bids, and vendor selection and contracting. On site project management included supervision contract supervisors, multiple drilling rigs, and completion crews. Personal supervision of 600 foam frac jobs.

- Wellsite supervision of drilling, completion, testing, and plugging operations throughout Montana.

- In 1990, managed one of the first drilling programs in the Powder River Basin coalbed methane play. Handled geology, reservoir engineering, field operations, support to gas contract negotiations and other operational matters.

- In 2004, founded Remuda Energy Development, LLC to develop prospects and establish my own production and reserves. Discovered and developed the Hat Creek gas field in Niobrara County, WY. Drilled and completed 8 producing wells, built 20 miles of gas line to develop gas market. Field EUR is approximately 11 BCF, Remuda currently has other production throughout Wyoming, Montana, north and South Dakota.

- In 2014, assumed operations for independent operator for 33 wells in NW Colorado. Our company provides all operating services, from the field through accounting. The project also has ongoing development drilling projects.

February 1978 - August 1984: **Petro Lewis Corporation, Various Locations**

Held various engineering and management positions. Experience in virtually every oil and gas basin in the Continental United States as well as Prudhoe Bay field, Alaska. Employment locations included Denver, CO; Bakersfield, CA; Oklahoma City, OK. Technical progression from wellsite supervision through petroleum engineering and management experience from operations through regional management in all oil and gas disciplines. Last position held: General Manager of the Mid Continent Region with responsibility for a staff of 165, 900 operated wells, 2600 non operated wells, managing a capital budget of $6 million per year, generating $60 million per year in operating profit.

July 1974 - January 1978: **Unocal, Ventura, CA**

Various positions in drilling, production and reservoir engineering. Activities included operations, development, and exploration of both onshore and offshore properties.

EDUCATION AND PROFESSIONAL CREDENTIALS

- B.S. Petroleum Engineering, June 1974; A.A. English, June 1974
  Montana College of Mineral Science and Technology, Butte, Montana

- Registered Professional Engineer: State of Montana: 4303PE
  State of Oklahoma: PE14085
  State of North Dakota PE 5886
  State of Wyoming PE 12212

ASSOCIATIONS

Society of Petroleum Engineers
Society of Petroleum Evaluation Engineers
Montana Geological Society
Montana Petroleum Association
National Society of Professional Engineers

Because together they are voluminous, the following exhibits have been provided only on the attached CD:

Exhibit__(TKH-2-1)

Exhibit__(TKH-2-2)

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF JOHN D. HINES

ON BEHALF OF NORTHWESTERN ENERGY

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Role of Future Natural Gas Production Acquisitions	16

1 **Witness Information**

2 **Q. Please state your name and business address.**

3 **A.** My name is John D. Hines. My business address is 11 East Park Street,

4 Butte, Montana 59701.

5

6 **Q. By whom are you employed and in what capacity?**

7 **A.** I am the Vice President of Supply at NorthWestern Energy

8 ("NorthWestern").

9

10 **Q. How long have you been employed in your current position?**

11 **A.** I have been in this position for over five years.

12

13 **Q. What are your responsibilities and duties in your current position?**

14 **A.** I am the NorthWestern Energy officer directly responsible for overseeing

15 the functional areas of electric and natural gas planning, electric

16 generation, natural gas production, and energy marketing, which includes

17 purchasing of natural gas. I am also responsible for the lands and

18 permitting, and the environmental compliance functions for NorthWestern.

19

20 **Q. Please summarize your educational and employment history.**

21 **A.** I earned both a Bachelor's degree and a Master's degree in Economics

22 from the University of Montana. I have over 25 years' experience in the

23 energy sector including working as a consultant to public interest groups

on energy issues and as an economist for the Northwest Power and Conservation Council ("Council").

In 2002, Governor Judy Martz appointed me to serve as one of Montana's two representatives to the Council. While working as a Council member I served on the Council's Executive and Power Committees.

In 2005 I joined NorthWestern as Director of Energy Supply Planning. I became the Chief Energy Supply Officer in 2008 and have served as Vice President - Supply since 2011.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I am providing policy testimony regarding the acquisitions of natural gas production and gathering assets, which are a component of the 2016 Natural Gas General Rate Case. The natural gas production assets that I discuss are commonly referred to as Bear Paw (NFR), South Bear Paw (Devon), Black Hills, and several very small properties (in total referred to as "natural gas production assets"). The natural gas production asset acquisitions, including their individual qualities and financial attributes, are fully described including discussions regarding purchase price, price per dekatherm ("Dkt"), quantities, and assumed duration of production, in the Prefiled Direct Testimonies of Travis E. Meyer ("Meyer Direct Testimony"),

Bleau J. LaFave ("LaFave Direct Testimony") and Patrick E. Callahan ("Callahan Direct Testimony").

In this testimony, I discuss the following:

1) An overview of NorthWestern's approach to managing its natural gas portfolio for its core supply customers;
2) The benefits of owning natural gas production assets to serve NorthWestern's core gas customers;
3) NorthWestern's overall approach to evaluating and purchasing natural gas productions assets; and
4) NorthWestern's perspective regarding future potential natural gas production acquisitions.

Natural Gas Supply Operational Objectives

Q. Please describe NorthWestern's objectives in operating the natural gas supply procurement function.

A. NorthWestern has three primary objectives in operating the natural gas supply procurement function. NorthWestern focuses on providing our core customers with reliable gas supply, at reasonable and stable prices, and assuring NorthWestern cost recovery of all prudently incurred natural gas supply-related expenditures and investments. I address these three objectives below.

- Reliable gas supply:

NorthWestern is responsible for meeting its core customers' natural gas demand throughout the course of the year. However, our customers' demand is extremely seasonal with roughly 69% of the total yearly demand occurring over the five winter months (November – March). Therefore, NorthWestern focuses on ensuring sufficient natural gas to serve our customers for the important winter season and peak winter requirements. As discussed in the Prefiled Direct Testimony of John M. Smith ("J. Smith Direct Testimony"), NorthWestern does this through a combination of flowing gas contracts, as well as the use of storage and owned natural gas production assets.

- Reasonably and stably priced natural gas supply:

NorthWestern, consistent with Montana Public Service Commission ("Commission") rules, develops a natural gas portfolio that seeks to dampen price volatility (compared, for example, to a total reliance on market purchases at index rates). For about a decade (since the 2006 Natural Gas Biennial Procurement Plan) NorthWestern has identified ownership of natural gas production assets as a mechanism to dampen both short-term and longer-term market price fluctuations for our customers. However, since the 2012 Natural Gas Biennial Procurement Plan filed in Docket No. N2012.12.125 ("2012 Plan"),

NorthWestern has viewed ownership of natural gas production as a preferred mechanism to reduce natural gas price volatility and to help maintain reliability.

In concert with price stability, NorthWestern also develops a natural gas portfolio that is reasonably priced. NorthWestern maintains a disciplined approach to ascribing value to the natural gas production assets it attempts to purchase, first by submitting a bid value that is less than the same amount of gas valued at the then-current natural gas market price forecast and second by valuing only proved producing reserves.

- Financial sustainability of utility

NorthWestern works diligently to implement the previous two objectives. To support the utility's financial sustainability, neither NorthWestern nor its shareholders should be penalized for prudent actions it takes on behalf of customers to maintain a reliable, reasonable, and stably priced natural gas supply. The revenue requirements for natural gas production assets should be recovered by NorthWestern.

Owned natural gas supply is a means to meet all three objectives. To ensure its financial sustainability, NorthWestern strives to follow

Commission directives, found either in Commission Comments on previous Natural Gas Supply Plans or Commission Orders.

Benefits from Owning Natural Gas Production Assets

Q. How does owning natural gas production assets provide greater reliability for core customers?

A. As noted earlier in my testimony, adequate supply during winter months is critical; winter peak-day consumption is nearly 15 times higher than the minimum consumption for a summer day. Given the adverse effects of curtailing customers during a critical heating day, NorthWestern manages its natural gas supply portfolio first and foremost in a manner that supports a reliable supply of natural gas for the winter heating season, especially for peak winter days.

Owned natural gas production assets contribute to supporting a reliable supply in several different ways. First, the supply of gas is firm; this means that it is available during critical or high demand times. Second, as described in detail in the Callahan Direct Testimony, the natural gas production assets are located within our system, lessening deliverability risk to our customers. One of NorthWestern's acquisition principles, explained in the LaFave Direct Testimony, is a preference for acquiring natural gas production assets that are first, connected directly to our system and second, can be delivered to NorthWestern's system. Third,

NorthWestern has seen a decline in natural gas volumes from its Montana sources for natural gas supply (both owned and contracted natural gas supply). The observed decline in natural gas volumes on NorthWestern's system appears to be a function of expected declines as wells become depleted, well shut-ins, and a lack of drilling investment to maintain or enhance production. As discussed in the Callahan Direct Testimony, NorthWestern's ownership of natural gas assets can enhance reliability because of the ability to increase or maintain supply output from a natural gas field if economic conditions allow.

NorthWestern ownership of natural gas production assets has helped maintain the use of this natural gas by NorthWestern's customers in Montana. As discussed in the J. Smith Direct Testimony, the acquisition of the natural gas production assets ensured that this natural gas would only serve NorthWestern customers and not flow to other areas.

Finally, ownership of natural gas supply has become more critical as on-system natural gas, both owned and contracted, declines over time. As less gas is available in Montana, NorthWestern must rely more on sources from Canada. However, as discussed in the Prefiled Direct Testimony of Michael R. Cashell, NorthWestern is concerned about significant limitations on NorthWestern's ability to import greater quantities of supply

1 into Montana, absent substantial upgrades to our natural gas
2 transportation system.
3
4 **Q. How does owning natural gas production assets help provide**
5 **reasonably and stably priced gas supply?**
6 **A.** First, if the owned natural gas production is located on NorthWestern's
7 gas transmission system, NorthWestern's natural gas portfolio costs are
8 reduced because there are no additional transportation costs to serve
9 customers compared to contracts from Canada or elsewhere off-system.
10
11 Second, when developing a bid price for assets prior to any purchase
12 NorthWestern explicitly takes into account certain pricing principles which
13 were developed to provide a framework for considering customer benefits
14 from a purchase of gas production. These principles are set forth in the
15 2012 Plan and discussed in the LaFave Direct Testimony. These pricing
16 principles were also incorporated into and analyzed in the pre-acquisition
17 modeling addressed in the Meyer Direct Testimony.
18
19 Third, flowing gas contracts are normally priced at some type of market
20 index, that is they fluctuate in price and thus the cost to customers
21 fluctuates according to both short- and long-term market conditions and
22 expectations. NorthWestern-owned natural gas production is included in
23 natural gas supply rates at an authorized regulated cost of service that is

not subject to the effects of external factors such as market variability.

Fourth, the J. Smith Direct Testimony discusses how market purchases at fixed prices are typically not available for contract lengths longer than one to three years into the future. While owned natural gas production lessens the short-term viability of market fluctuations, it also serves to dampen the effects of long-term market price trends. Removing market influences for 20 years or more for a portion of the natural gas supply portfolio provides a price hedge against upward pricing trends of the natural gas supply market. NorthWestern includes ownership of natural gas assets, prudently acquired, as part of its overall approach to portfolio management because it provides a long-term hedge to market trends by removing market price volatility for the life of the asset.

Adherence to Natural Gas Supply Acquisition Principles

Q. Has the Commission provided guidance on whether NorthWestern should consider owned natural gas production as part of an overall portfolio approach to serving core customers?

A. Yes. Potential ownership of natural gas assets is the central component of NorthWestern's long-term hedging strategy, and the Commission has confirmed the merits of considering ownership as part of its portfolio approach. In NorthWestern's 2010 Natural Gas Biennial Procurement

Plan, Docket No. N2010.12.111, in ¶ 49 of its Comments, the Commission stated:

> *"Failure to examine the possibility of purchasing reserves given the recent growth in natural gas reserves in the United States and the resulting decline in natural gas prices* ***would not be prudent."*** *(emphasis added)*

In the 2012 Plan NorthWestern stated that the continued evaluation and acquisition of natural gas production assets, when it makes sense, was the preferred method of long-term physical and financial hedging. In ¶ 32 of its Comments on the 2012 Plan, the Commission stated:

> *"The Commission's view on NorthWestern's acquisition of natural gas reserves or production is unchanged from its comments on the 2010 Plan. Failure to examine the possibility of purchasing reserves given the recent growth in natural gas reserves in the United States and the resulting decline in natural gas prices would not be prudent. Owning natural gas reserves, or owning an interest in them, can result in benefits to ratepayers versus simply buying natural gas at market prices."*

Q. Has NorthWestern employed a set of principles when evaluating potential natural gas production assets?

A. Yes. NorthWestern has established a process that incorporates a set of principles to analyze potential natural gas production assets for ownership. While the inputs, for example forward market curve values, have changed over time, the use of these principles has continued. The unit revenue requirement/market price crossover point principle was included in the stipulation between NorthWestern and the Montana Consumer Counsel ("MCC") regarding the Battle Creek natural gas

1 production asset ("Battle Creek") acquisition, which was approved and
2 placed into rate base by the Commission in Docket No. D2012.3.25. The
3 principles by which NorthWestern currently evaluates natural gas
4 acquisitions were set forth in the 2012 Plan as part of NorthWestern's
5 approach to providing reliable and stably priced gas supply.
6
7 **Q. What are the principles that NorthWestern has established for**
8 **evaluating acquisition of natural gas production assets?**
9 **A.** In its 2012 Plan, NorthWestern provided a detailed description of five
10 overarching principles for reviewing and acquiring natural gas production
11 resources. At a high level they are: (1) Acquisition Properties Criteria; (2)
12 Utilization of Natural Gas Tracker as Interim Cost Recovery Method; (3)
13 Analytical Evaluation Approach (Financial Modeling), (4) Volume of
14 Owned Natural Gas Production (billion cubic feet ("Bcf")); and (5) Natural
15 Gas Production Resource Acquisition Thresholds to Serve Retail
16 Customers. The LaFave Direct Testimony discusses these principles in
17 detail.
18
19 **Q. Did NorthWestern follow the principles included in the 2012 Plan**
20 **when evaluating the natural gas production assets?**
21 **A.** Yes. The LaFave Direct Testimony takes each of the principles set forth
22 in the 2012 Plan and compares NorthWestern's assessments for the
23

natural gas production assets with them. NorthWestern adhered to these principles in each of the transactions.

Q. Has the Commission provided any guidance on the acquisition of natural gas production assets other than its comments on NorthWestern's biennial procurement plans?

A. Yes. NorthWestern sought approval of acquisition and inclusion of Battle Creek in rate base in Docket No. D2012.3.25. In Order No.7210b issued on November 16, 2012 in that docket, the Commission approved the acquisition and rate basing of Battle Creek. During the docket, the MCC and NorthWestern entered into a Unit Cost/Market-Price Crossover Stipulation for future acquisitions of natural gas. The Commission found the Unit Cost/Market-Price Crossover Stipulation to be in the public interest and approved this methodology. The discussions between the parties in the Battle Creek docket informed and guided NorthWestern in developing the evaluation and acquisition parameters identified in the 2012 Plan.

Q. Has the Commission provided guidance on how the prudence of NorthWestern's natural gas procurement activities will be evaluated?

A. Yes. In ¶¶ 32 and 34 of the Commission's Comments on the 2012 Plan, the Commission outlines the key principles for regulatory review. First, the Commission defines the main factors NorthWestern should evaluate –

"volumes, price, and term". Second, the Commission states that it expects NorthWestern to follow the principles or parameters included in the 2012 Plan.

Q. Did NorthWestern evaluate volumes, price, and term in the natural gas production asset transactions it is seeking to place into rate base?

A. Yes. The Meyer, LaFave, and Callahan Direct Testimonies discuss the volumes, the price of each asset on a per-unit and total cost basis, and the expected life of production. Their testimonies demonstrate that NorthWestern analyzed volumes, price, and term for Bear Paw (NFR), South Bear Paw (Devon), and Black Hills in a manner consistent with the principles set forth in the 2012 Plan. Moreover, the respective analyses for each of the transactions confirm that the purchase price paid for each acquisition was consistent with the principles developed in the 2012 Plan. Therefore, the natural gas production asset acquisitions are also consistent with the Commission's Comments on the 2012 Plan including: "The Commission expects NorthWestern to purchase natural gas following the concepts contained in the 2012 Plan" (¶ 34).

Q. Did NorthWestern evaluate each of the natural gas production assets based upon information available to NorthWestern at the time of the transactions?

1 **A.** Yes. First, it is important to note that the Commission set forth its
2 standard for information to be used in evaluating prudency. In ¶ 34 of its
3 Comments on the 2012 Plan, the Commission stated: "Evaluation of the
4 prudence of NWE's natural gas procurement activities will be based
5 ***solely*** on information available to NWE at the time transactions were
6 done." (Emphasis added.) NorthWestern used timely market pricing
7 information; the total quantities acquired were less than the maximums set
8 forth as a principle, and customer pricing values were consistent with the
9 pricing metrics developed in the 2012 Plan.
10
11 **Q. Why are the principles that you have discussed appropriate?**
12 **A.** Ownership of natural gas provides many benefits to our customers
13 including price stability and reliability. The reliable provision of natural gas
14 supply to our customers is based on three fundamental pillars: on-system
15 supply, storage, and imports from Canada. Ownership of on-system
16 supply is important to preserving reliability. As discussed previously, the
17 availability of on-system supply has decreased, and ownership of natural
18 gas production reserves those natural gas assets for NorthWestern's
19 customers. Ownership also helps stabilize or dampen market price
20 volatility.
21
22 The principles provide a transparent framework for evaluating potential
23 natural gas production assets that is flexible in a manner that dictates

1 shorter forecast periods for customers to see benefits from transactions.
2 For example, the calculated levelized dollar per Dkt of a potential
3 acquisition defines volumes and crossover points and is designed to
4 shorten the period in which customers are to see a benefit (crossover
5 period) when market prices are higher and extend the crossover period
6 when future market prices are lower. The principles are also important to
7 NorthWestern because they provide the utility with greater regulatory
8 clarity regarding how it should evaluate potential natural gas acquisitions.
9
10 **Role of Future Natural Gas Production Acquisitions**
11 **Q. Does NorthWestern support additional natural gas production**
12 **acquisitions as part of its future strategy for serving its natural gas**
13 **customers?**
14 **A.** Yes. NorthWestern has been evaluating potential properties on an
15 ongoing basis, but, other than a few small purchases, NorthWestern has
16 not successfully entered into a transaction since the 2013 South Bear Paw
17 (Devon) transaction. Meanwhile, volumes of owned gas and thus the
18 percentage of the portfolio physically and financially hedged continues to
19 decline. This is due to owned natural gas production depletion rates. For
20 example, depletion values for 2015 ranged from 7% to 13%.
21
22 As discussed in the Callahan Direct Testimony, NorthWestern's overall
23 owned production as a percentage of the overall natural gas supply

portfolio is declining. In 2013, production of owned natural gas assets comprised approximately 36% of the total portfolio. For 2017, absent another acquisition, owned gas will only provide about 24% of the supply portfolio.

In addition to replacing the amount of owned natural gas occurring because of depletion, planned new natural gas-fired electric generation for NorthWestern's electric customers further increases the likely need for additional owned natural gas production. As is the case for hedging our core customers' natural gas portfolio, hedging a portion of gas to be used to serve our electricity customers is also important. The use of owned gas to serve natural gas-fired electric generation was also addressed in the Commission's comments on the 2012 Plan. The Commission stated in ¶ 33 that: "NorthWestern's proposal to use a pro-rata allocation of natural gas production resource acquisitions that will serve both its retail natural gas customers and Electric Utility natural gas-fired generation seems reasonable".

Q. Why has NorthWestern not acquired additional natural gas assets?

A. NorthWestern has submitted bids for several potential assets, consistent with the acquisition principles. However, NorthWestern's bids were insufficient to entice a seller into a transaction.

1 **Q. Please discuss reasons why NorthWestern believes it has recently**
2 **been unsuccessful in acquiring additional natural gas assets.**
3 **A.** I will discuss two reasons why NorthWestern believes it has been
4 unsuccessful in its recent efforts to acquire additional natural gas assets.
5 First is the relatively low natural gas price forecast it uses in developing a
6 value for production assets compared to sellers' expectations. Second,
7 and somewhat related, is the flat shape of the forecast market price curve
8 for natural gas. Both of these issues make it difficult to provide a
9 competitive bid price and still meet the crossover threshold that, as
10 discussed in detail in the LaFave Direct Testimony, is a principle and is
11 part of the acquisition evaluation.
12
13 **Q. Please discuss the crossover issue in more detail.**
14 **A.** As discussed in the LaFave Direct Testimony, there are a defined number
15 of years (depending upon the 20-year levelized revenue requirement
16 calculation) in which the future unit revenue requirement must be lower
17 than the market price – the crossover point. For example, if the 20-year
18 levelized unit revenue requirement is less than $4/Dkt, the crossover point
19 must be five years or less. The intent is to provide greater certainty of
20 benefits flowing to NorthWestern's customers, an intent NorthWestern
21 supports. However, if forecasts of the natural gas market price continue
22 to be both low and relatively flat into the future, it appears that the
23 crossover principle will be very difficult to meet and have a successful

1 transaction, and NorthWestern will be unable to lock in long-term
2 production assets at the extremely favorable prices at which the market is
3 currently trading.
4
5 **Q. Given the current and forecast low price of natural gas, does**
6 **NorthWestern support consideration of modifications to any of the**
7 **acquisition principles?**
8 **A.** Yes. NorthWestern supports consideration of extending the crossover
9 period beyond five years if the levelized forecast of market is below a
10 certain dollar threshold. While NorthWestern does not have an explicit
11 proposal at this time, NorthWestern would like to be able to acquire
12 natural gas production at prices reflecting current market levels.
13
14 The 2012 Plan explicitly recognizes that the parameters established to
15 evaluate thresholds for natural gas acquisitions to serve retail customers
16 were "based on the future natural gas market prices and shape of the
17 forward curve at the time NWE and the MCC were drafting the Stipulation
18 Agreement that was filed and approved by the MPSC in Docket No.
19 D2012.3.25". (2012 Plan p. 18.) The parameters, from NorthWestern's
20 perspective, have sufficiently changed to justify evaluating the parameters
21 of the crossover principle.
22
23 **Q. Please summarize your testimony.**

1 **A.** Ownership of natural gas production is an important tool used by
2 NorthWestern in managing its natural gas portfolio. Reliability and price
3 stability are important attributes for our customers, and owned gas
4 production is an important means of achieving these attributes.
5 NorthWestern has taken a disciplined approach in evaluating and
6 acquiring natural gas production assets. The evaluation principles were
7 presented in the 2012 Plan, and the Commission commented upon and
8 generally affirmed them.
9
10 NorthWestern supports additional ongoing purchases of owned natural
11 gas production as a continued means of providing value to its customers
12 and to the utility. The evaluation principles are largely appropriate.
13 However, the Commission should consider exploring whether the
14 crossover point principle, recognizing the characteristics of today's
15 forward natural gas curves, should be modified to help facilitate success in
16 future acquisition opportunities.
17
18 **Q. Does this conclude your testimony?**
19 **A.** Yes.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.9.68
Natural Gas General Rate Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF PATRICK R. CORCORAN

ON BEHALF OF NORTHWESTERN ENERGY

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Exhibits

Natural Gas Production Ratemaking Alternatives Comparisons and Results	Exhibit__(PRC-1)

Witness Information

Q. Please state your name and business address.

A. My name is Patrick R. Corcoran, and my business address is 11 East Park Street, Butte, Montana 59701.

Q. By whom and in what capacity are you employed?

A. I am employed by NorthWestern Energy ("NorthWestern") as the Vice President of Government and Regulatory Affairs.

Q. Please summarize your education and employment experience.

A. I attended the Montana College of Mineral Science and Technology, Butte Montana, receiving an Associate of Engineering Science degree and a Bachelor of Science degree in Computer Science. I have also attended the University of Idaho's Public Utilities Executive Course and many other courses, seminars and sessions on business, utility, and regulatory subjects.

I began work as a computer programmer for the then Montana Power Company ("MPC") in January 1979. After progressing through a number of positions in the Regulatory Affairs Department, I became the MPC Vice President of Regulatory Affairs in September 2000 and a NorthWestern Vice President in 2002.

1 **Q. What are your responsibilities as Vice President of Government and**
2 **Regulatory Affairs?**
3 **A.** I am the officer in charge of state and federal government and regulatory
4 affairs for NorthWestern in Montana, South Dakota, Nebraska, and at the
5 federal level. I have broad utility knowledge and experience, and I am
6 familiar with many aspects of the utility business. I am an active
7 participant in regulatory proceedings and forums before the state and
8 federal regulatory commissions, and I have testified on various regulatory
9 and utility-related business matters. I am also responsible for
10 NorthWestern's energy conservation, demand-side management, and
11 Universal System Benefits programs and for other related
12 programs/activities. Additionally, I am responsible for electric load
13 research and related activities including the collection, analysis, and
14 reporting of electric load data to meet various internal and external needs
15 in Montana. I have been actively involved in and guided these efforts for
16 many years.
17
18 As part of my overall responsibilities, I play a key role in formulating,
19 shaping, and guiding internal and external regulatory and public policy
20 matters for NorthWestern.
21

Purpose of Testimony

Q. What is the purpose of your testimony?

A. My testimony addresses "the appropriate ratemaking treatment for NorthWestern Energy's Natural Gas Production Assets", as required by Montana Public Service Commission ("MPSC" or "Commission") Order No. 7282d in Consolidated Docket Nos. D2013.5.34/D2014.5.47. Both the Montana Consumer Counsel ("MCC") and the Commission expressed concerns about the appropriateness of cost recovery for the gas production assets using the conventional ratemaking treatment historically employed by the Commission.

The Commission went on to express its interest in exploring "at least three differing approaches to ratemaking for the gas production assets, including: a multi-year revenue requirement with annually stair-stepping rates based on an historic test year and several years of forecast data; annual updating of revenue requirements based upon actual cost of service through a tracker; and a traditional method of permanent rates set using a historic test year." (Order No. 7282d, ¶ 35)

My testimony will present NorthWestern's analysis of the three approaches described above and its recommendation to the Commission.

Alternative Ratemaking Analysis

Q. Describe each of three ratemaking approaches NorthWestern analyzed.

A. The three approaches are described below:

Traditional

The long standing Traditional ratemaking approach of the Commission is embedded in the existing Administrative Rules of Montana, and it is based on an analysis of costs for a 12-month historic test year. "The statement of the cost of service shall contain an analysis of system costs as reflected on the filing utility's books for a test period consisting of 12 months actual experience ending no earlier than 9 months prior to the date of filing..." (ARM 38.5.106). This approach also allows for known and measurable adjustments to the historic test year data that are known with certainty and measurable with reasonable accuracy and occur within 12 months of the end of the test year.

Accordingly, rates established on this basis are intended to provide the utility a reasonable opportunity to recover these costs, including the allowed rate of return on its investments, between rate cases. Once utility rates are set based on the historic test year, the utility has the discretion to make rate filings from time to time as necessary when current rate revenues no longer cover the cost of utility service.

1 Annual True-up

2 Under this approach the utility is allowed to recover the actual cost of
3 service from year to year. To the extent the utility's actual rate revenues are
4 not equal to the actual cost of service for whatever reason, the public utility
5 is allowed to true-up revenues to the actual annual cost of service.
6 Likewise, if actual revenues exceed the actual cost of service, the utility
7 refunds any over-collection to customers. In this case, the Annual True-up
8 would reflect the recovery of the actual annual cost of service for
9 NorthWestern's natural gas production assets.
10
11 The annual true-up would require calendar year tracking (January to
12 December). Under this approach the rates necessary to cover the cost of
13 service for the gas production assets in each tracking year would be
14 forecasted, then trued-up to each year's actual cost of service and loads on
15 an annual basis, in the next annual filing.
16
17 Multi-Year

18 A Multi-Year approach establishes the recovery of a utility's cost of service
19 for a defined period of time, for example, four years. The first year is set in a
20 Traditional filing, and during the same proceeding, the cost of service for
21 each of the following three years is set based on a forecast of each year's
22 revenue requirement.
23

1 **Q. Has NorthWestern conducted an analysis of each of these three**
2 **approaches using actual and forecast data for its natural gas**
3 **production assets?**
4 **A.** Yes. Exhibit__(PRC-1) presents an analysis and comparison of the three
5 approaches. This analysis is presented in summary form. The detailed cost
6 of service information supporting this analysis was prepared by Mr. Patrick
7 DiFronzo and is included as part of his prefiled direct testimony in this filing.
8 The first full calendar year that each of NorthWestern's gas production
9 assets was placed in rates was:

Battle Creek	2011
Bear Paw (NFR)	2013
South Bear Paw (Devon)	2014

14 The analysis is based on the actual annual cost of service and retail load
15 data available from 2011 through 2015. Forecast data from NorthWestern's
16 latest financial forecast is used for the years 2016 through 2019.
17
18 The data and analysis are intended as an illustrative view of the three
19 scenarios over the nine-year period from 2011 through 2019 using available
20 data. They do not necessarily represent what has actually taken place,
21 since two of three gas production assets, Bear Paw (NFR) and South Bear
22 Paw (Devon), were in rates on an interim basis using the bridge rate
23 concept up until now and four of the years are forecast. Further, the

analysis includes certain simplifying assumptions regarding, for example, the timing of rate adjustments. Additional descriptions of the individual scenarios are provided below.

Q. What is the primary purpose of the analysis?

A. The primary purpose of the analysis is to compare and contrast the resulting bill rate revenues realized by NorthWestern under each of the alternatives. Each alternative assumes that bridge rates were in effect for the first two years after the purchase of Bear Paw (NFR) in 2012 and South Bear Paw (Devon) in 2013. Battle Creek had already been included in rate base and reflected in permanent rates based on a Commission final order since 2012. Annual rate revenue calculations are presented for each of the scenarios.

Q. Describe NorthWestern's analysis of each of the alternatives and a summary of the results.

A. The analysis of each alternative includes individual calculations for NorthWestern's Battle Creek, Bear Paw (NFR), and South Bear Paw (Devon) gas production assets and a sum total of the three. Each alternative is briefly described below:

Traditional – Gas production rate revenues are determined from rates based on Historical Test Years. Exhibit__(PRC-1) page 1 presents NorthWestern's Traditional ratemaking analysis for the gas production assets. This analysis

assumes there are two Traditional historic test year rate filings for each of the gas production assets and implementation of the resulting rates lags the test year by two years. Once these rates are set, they are in place until rates are reset to reflect the next test year rate filing. The following table summarizes the test year and related rate effective date assumptions for each asset:

	Test Year 1	Rate Effective Dates	Test Year 2	Rate Effective Dates
Battle Creek	2011	2013, 2014, 2015 & 2016	2015	2017, 2018 & 2019
NFR	2013	2015 & 2016	2015	2017, 2018 & 2019
Devon	2014	2016	2015	2017, 2018 & 2019

The resulting rate revenues for each year are computed and shown for each gas production asset and for all three assets in total.

Annual True-up – Gas production rate revenues are equal to actual revenue requirement data. Exhibit__(PRC-1) page 2 presents NorthWestern's True-up ratemaking analysis for the gas production assets. Since the actual rate revenues for each year are trued-up to the actual revenue requirement in each year, this analysis sets the actual rate revenues to each year's revenue requirement for each gas production asset and for all three assets in total.

1 Multi-Year – Gas production rate revenues are initially determined from
2 rates set based on Traditional filings using the same test years and rate
3 revenues as those used for the Traditional analysis and assuming the same
4 two-year lag prior to implementation of related rates. Rate revenues are
5 equal to forecast revenue requirements data for the remaining years.
6 Exhibit__(PRC-1) page 3 presents NorthWestern's Multi-Year ratemaking
7 analysis for the gas production assets. It is essentially a combination of the
8 Traditional and True-up methods. The annual rate revenues for the
9 production assets are totaled for each year.
10
11 **Alternative Ratemaking Analysis Results**
12 **Q. What were the results of the analysis?**
13 **A.** Recall that the primary purpose of the analysis was to compare and contrast
14 the resulting bill rate revenues realized by NorthWestern under each of the
15 ratemaking alternatives. The results of this analysis are illustrated in the
16 following table, which is taken from Exhibit__(PRC-1):

Table 1

NorthWestern Energy Natural Gas Production Assets MPSC Order No. 7282d Alternative Ratemaking Comparisons				
Year		Illustrative Total Test Year Rate Revenues	Illustrative Total True Up Rate Revenues	Illustrative Total Multi Year Rate Revenues
2011	A	$ 2,463,398	$ 2,463,398	$ 2,463,398
2012	A	$ 2,397,592	$ 2,397,592	$ 2,397,592
2013	A	$ 7,389,391	$ 6,990,402	$ 7,389,391
2014	A	$ 23,640,072	$ 23,224,770	$ 23,224,770
2015	A	$ 24,117,043	$ 24,135,558	$ 24,163,009
2016	F	$ 23,687,042	$ 23,779,036	$ 23,820,595
2017	F	$ 24,528,914	$ 22,791,154	$ 24,528,914
2018	F	$ 24,728,254	$ 22,060,367	$ 22,060,367
2019	F	$ 24,929,392	$ 21,454,310	$ 21,454,310
Totals		$ 157,881,098	$ 149,296,587	$ 151,502,347
Difference to Test Year			$ (8,584,511)	$ (6,378,752)
Difference to Multi Year		$ 6,378,752	$ (2,205,760)	
Difference to True-Up		$ 8,584,511		$ 2,205,760
Note:				
A = Actual				
F = Forecast				

As shown in Table 1, the Traditional alternative results in $8.6 million more rate revenues than the True-Up alternative and $6.4 million more than the Multi-Year alternative.

NorthWestern's Recommendation

Q. After evaluating the subject matter and NorthWestern's own analysis of the three alternative rate-making approaches set out by the Commission, what does NorthWestern recommend as the appropriate ratemaking approach for its Natural Gas Production Assets going forward?

1 **A.** NorthWestern recommends that the Commission implement the Annual
2 True-up ratemaking approach for its Natural Gas Production Assets.
3
4 **Q. Why does NorthWestern recommend the Annual True-up approach?**
5 **A.** Under normal circumstances NorthWestern would oppose segregating the
6 gas production assets traditionally treated as part of a utility's overall cost of
7 service under the Commission filing requirements. However, NorthWestern
8 recognizes that the ratemaking treatment of the gas production assets has
9 not been normal since the first gas production asset purchase. This started
10 with the implementation of the "bridge rates" to commence recovery of the
11 revenue requirement for these acquisitions in a timely fashion on an interim
12 basis. Without the bridge rates it is doubtful NorthWestern would have even
13 been able to acquire these assets.
14
15 Second, NorthWestern also recognizes the significant passage of time from
16 the acquisition of Bear Paw (NFR) and South Bear Paw (Devon) to now.
17 While NorthWestern intended to make more timely filings to request rate
18 base treatment of the Bear Paw (NFR) and South Bear Paw (Devon) assets
19 on a permanent basis, this did not happen primarily due to the time and
20 resources required to support the numerous other filings made by
21 NorthWestern in recent years.
22

1 Finally, NorthWestern remains interested in future natural gas production
2 asset acquisitions, if opportunities present themselves in the future. The
3 use of the bridge rate as an ongoing tool in its toolbox remains an
4 important part of NorthWestern's ability to acquire such assets. This was
5 recognized in Order No. 7282d ¶ 38, where the Commission reauthorized
6 the use of bridge rates for gas production properties.
7
8 Given the circumstances, NorthWestern chose the best alternative from a
9 customer perspective, and one that allows NorthWestern to recover no
10 more or no less than the actual cost of service. This approach also
11 addresses the Commission's concern about higher cost recovery between
12 rate cases in the early years.
13
14 In conjunction with the continuation of the bridging mechanism for new
15 gas production purchases, NorthWestern can get comfortable with an
16 Annual True-up to the actual revenue requirements for the gas production
17 assets.
18
19 **Q. When does NorthWestern propose to make the Annual True-up**
20 **filings?**
21 **A.** The Annual True-ups would be made in April of each year, with rates in
22 effect on an interim basis starting July 1 until a final order is issued.
23

1 **Q. Do you have any concerns about Annual True-up filings becoming**
2 **more like larger general rate filing contested cases on an annual**
3 **basis?**
4 **A.** Yes. However, NorthWestern hopes that once the template and practice
5 is in place for these types of annual filings, they would become more
6 procedural in nature. NorthWestern is particularly concerned about
7 rearguing capital structure and cost of capital, in particular allowed rate of
8 return, on an annual basis. Therefore, NorthWestern proposes that the
9 allowed rate of return for purposes of the Annual True-ups be set at the
10 allowed rate of return authorized in NorthWestern's last general rate filing.
11
12 **Q. And finally, has NorthWestern conferred with the MCC on this**
13 **proposed approach as the Commission encouraged in ¶ 34 of Order**
14 **No. 7282d and as called for in ¶ 8(c) of the parties' Stipulation and**
15 **Settlement Agreement in Docket No. D2014.7.59?**
16 **A.** Yes. NorthWestern and the MCC did not agree on a common approach.
17
18 **Q. Does this conclude your testimony?**
19 **A.** Yes, it does.

NorthWestern Energy Natural Gas Production Assets
MPSC Order No. 7282d Alternative Ratemaking Comparisons

Year		Retail Loads Dkts	Battle Creek Rev Req (BC)	BC Test Year Unit Rates	BC Billing Unit Rate	Illustrative BC Billed Rate Revenues	Bear Paw Rev Req (NFR)	NFR Test Year Unit Rate	NFR Billing Unit Rate	Illustrative NFR Billed Rate Revenues	South Bear Paw Rev Req (Devon)	Devon Test Year Unit Rate	Devon Billing Unit Rate	Illustrative Devon Billed Rate Revenues	Illustrative Total Test Year Billed Rate Revenues
2011	A	19,912,975	$ 2,463,398	$ 0.12		$ 2,463,398									$ 2,463,398
2012	A	19,170,933	$ 2,397,592	$ 0.13		$ 2,397,592									$ 2,397,592
2013	A	19,659,839	$ 2,033,094	$ 0.10	$ 0.12	$ 2,432,083	$ 4,957,308	$ 0.25		$ 4,957,308					$ 7,389,391
2014	A	19,686,697	$ 2,020,104	$ 0.10	$ 0.12	$ 2,435,406	$ 4,394,323	$ 0.22		$ 4,394,323	$ 16,810,343	$ 0.85		$ 16,810,343	$ 23,640,072
2015	A	19,106,584	$ 2,409,607	$ 0.13	$ 0.12	$ 2,363,641	$ 4,790,351	$ 0.25	$ 0.25	$ 4,817,802	$ 16,935,600	$ 0.89		$ 16,935,600	$ 24,117,043
2016	F	19,261,583	$ 2,478,456	$ 0.13	$ 0.12	$ 2,382,815	$ 4,894,799	$ 0.25	$ 0.25	$ 4,856,886	$ 16,405,781	$ 0.85	$ 0.85	$ 16,447,340	$ 23,687,042
2017	F	19,417,978	$ 2,440,549	$ 0.13	$ 0.13	$ 2,448,878	$ 4,672,996	$ 0.24	$ 0.25	$ 4,868,423	$ 15,677,609	$ 0.81	$ 0.89	$ 17,211,612	$ 24,528,914
2018	F	19,575,783	$ 2,421,608	$ 0.12	$ 0.13	$ 2,468,780	$ 4,565,111	$ 0.23	$ 0.25	$ 4,907,988	$ 15,073,648	$ 0.77	$ 0.89	$ 17,351,487	$ 24,728,254
2019	F	19,735,012	$ 2,410,336	$ 0.12	$ 0.13	$ 2,488,861	$ 4,489,750	$ 0.23	$ 0.25	$ 4,947,909	$ 14,554,224	$ 0.74	$ 0.89	$ 17,492,623	$ 24,929,392

Notes:
A = Actual
F = Forecast

Bridge
Test Year 1
Test Year 2

NorthWestern Energy Natural Gas Production Assets
MPSC Order No. 7282d Alternative Ratemaking Comparisons

Year		Retail Loads Dkts	Battle Creek Rev Req (BC)	BC True Up Unit Rates	BC Billing Unit Rate	Illustrative BC Billed Rate Revenues	Bear Paw Rev Req (NFR)	NFR True Up Unit Rate	NFR Billing Unit Rate	Illustrative NFR Billed Rate Revenues	South Bear Paw Rev Req (Devon)	Devon True Up Unit Rate	Devon Billing Unit Rate	Illustrative Devon Billed Rate Revenues	Illustrative Total True Up Billed Rate Revenues
2011	A	19,912,975	$ 2,463,398	$ 0.12		$ 2,463,398									$ 2,463,398
2012	A	19,170,933	$ 2,397,592	$ 0.13		$ 2,397,592									$ 2,397,592
2013	A	19,659,839	$ 2,033,094	$ 0.10	$ 0.10	$ 2,033,094	$ 4,957,308	$ 0.25		$ 4,957,308					$ 6,990,402
2014	A	19,686,697	$ 2,020,104	$ 0.10	$ 0.10	$ 2,020,104	$ 4,394,323	$ 0.22		$ 4,394,323	$ 16,810,343	$ 0.85		$ 16,810,343	$ 23,224,770
2015	A	19,106,584	$ 2,409,607	$ 0.13	$ 0.13	$ 2,409,607	$ 4,790,351	$ 0.25	$ 0.25	$ 4,790,351	$ 16,935,600	$ 0.89		$ 16,935,600	$ 24,135,558
2016	F	19,261,583	$ 2,478,456	$ 0.13	$ 0.13	$ 2,478,456	$ 4,894,799	$ 0.25	$ 0.25	$ 4,894,799	$ 16,405,781	$ 0.85	$ 0.85	$ 16,405,781	$ 23,779,036
2017	F	19,417,978	$ 2,440,549	$ 0.13	$ 0.13	$ 2,440,549	$ 4,672,996	$ 0.24	$ 0.24	$ 4,672,996	$ 15,677,609	$ 0.81	$ 0.81	$ 15,677,609	$ 22,791,154
2018	F	19,575,783	$ 2,421,608	$ 0.12	$ 0.12	$ 2,421,608	$ 4,565,111	$ 0.23	$ 0.23	$ 4,565,111	$ 15,073,648	$ 0.77	$ 0.77	$ 15,073,648	$ 22,060,367
2019	F	19,735,012	$ 2,410,336	$ 0.12	$ 0.12	$ 2,410,336	$ 4,489,750	$ 0.23	$ 0.23	$ 4,489,750	$ 14,554,224	$ 0.74	$ 0.74	$ 14,554,224	$ 21,454,310

Notes:
A = Actual
F = Forecast

Bridge

NorthWestern Energy Natural Gas Production Assets
MPSC Order No. 7282d Alternative Ratemaking Comparisons

Year		Retail Loads Dkts	Battle Creek Rev Req (BC)	BC Test Year Unit Rates	BC Billing Unit Rate	Illustrative BC Test Year Rate Revenues	Bear Paw Rev Req (NFR)	NFR Test Year Unit Rate	NFR Billing Unit Rate	Illustrative NFR Test Year Rate Revenues	South Bear Paw Rev Req (Devon)	Devon Test Year Unit Rate	Devon Billing Unit Rate	Illustrative Devon Test Year Rate Revenues	Illustrative Total Multi Year Billed Rate Revenues
2011	A	19,912,975	$ 2,463,398	$ 0.12		$ 2,463,398									$ 2,463,398
2012	A	19,170,933	$ 2,397,592	$ 0.13		$ 2,397,592									$ 2,397,592
2013	A	19,659,839	$ 2,033,094	$ 0.10	$ 0.12	$ 2,432,083	$ 4,957,308	$ 0.25		$ 4,957,308					$ 7,389,391
2014	A	19,686,697	$ 2,020,104	$ 0.10	$ 0.10	$ 2,020,104	$ 4,394,323	$ 0.22		$ 4,394,323	$ 16,810,343	$ 0.85		$ 16,810,343	$ 23,224,770
2015	A	19,106,584	$ 2,409,607	$ 0.13	$ 0.13	$ 2,409,607	$ 4,790,351	$ 0.25	$ 0.25	$ 4,817,802	$ 16,935,600	$ 0.89		$ 16,935,600	$ 24,163,009
2016	F	19,261,583	$ 2,478,456	$ 0.13	$ 0.13	$ 2,478,456	$ 4,894,799	$ 0.25	$ 0.25	$ 4,894,799	$ 16,405,781	$ 0.85	$ 0.85	$ 16,447,340	$ 23,820,595
2017	F	19,417,978	$ 2,440,549	$ 0.13	$ 0.13	$ 2,448,878	$ 4,672,996	$ 0.24	$ 0.25	$ 4,868,423	$ 15,677,609	$ 0.81	$ 0.89	$ 17,211,612	$ 24,528,914
2018	F	19,575,783	$ 2,421,608	$ 0.12	$ 0.12	$ 2,421,608	$ 4,565,111	$ 0.23	$ 0.23	$ 4,565,111	$ 15,073,648	$ 0.77	$ 0.77	$ 15,073,648	$ 22,060,367
2019	F	19,735,012	$ 2,410,336	$ 0.12	$ 0.12	$ 2,410,336	$ 4,489,750	$ 0.23	$ 0.23	$ 4,489,750	$ 14,554,224	$ 0.74	$ 0.74	$ 14,554,224	$ 21,454,310

Notes:
A = Actual
F = Forecast

Bridge
Test Year 1
Test Year 2

	A	B	C	D	E	F
1						Docket No. D2016.9.68
2						Exhibit__(PRC-1)
3						Page 4 of 5
4						
5		NorthWestern Energy Natural Gas Production Assets				
6		MPSC Order No. 7282d Alternative Ratemaking Comparisons				
7		Year		Illustrative Total Test Year Rate Revenues	Illustrative Total True Up Rate Revenues	Illustrative Total Multi Year Rate Revenues
8		2011	A	$ 2,463,398	$ 2,463,398	$ 2,463,398
9		2012	A	$ 2,397,592	$ 2,397,592	$ 2,397,592
10		2013	A	$ 7,389,391	$ 6,990,402	$ 7,389,391
11		2014	A	$ 23,640,072	$ 23,224,770	$ 23,224,770
12		2015	A	$ 24,117,043	$ 24,135,558	$ 24,163,009
13		2016	F	$ 23,687,042	$ 23,779,036	$ 23,820,595
14		2017	F	$ 24,528,914	$ 22,791,154	$ 24,528,914
15		2018	F	$ 24,728,254	$ 22,060,367	$ 22,060,367
16		2019	F	$ 24,929,392	$ 21,454,310	$ 21,454,310
17		Totals		$ 157,881,098	$ 149,296,587	$ 151,502,347
18		Difference to Test Year			$ (8,584,511)	$ (6,378,752)
19		Difference to Multi Year		$ 6,378,752	$ (2,205,760)	
20		Difference to True-Up		$ 8,584,511		$ 2,205,760
21						
22		Note:				
23		A = Actual				
24		F = Forecast				

	A	B	C	D
1			**Docket No. D2016.9.68**	
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3			**Page 5 of 5**	
4				
5				
6		NorthWestern Energy		
7		Natural Gas Utility		
8		**Normalized Retail Loads**		
9				
10		2011	19,912,975	
11		2012	19,170,933	
12		2013	19,659,839	
13		2014	19,686,697	
14		2015	19,106,584	
15		2016	19,261,583	
16		2017	19,417,978	
17		2018	19,575,783	
18		2019	19,735,012	
19				
20				