BEFORE THE DEPARTMENT OF PUBLIC SERVICE REGULATION

MONTANA PUBLIC SERVICE COMMISSION

DOCKET NO. D2013.5.33

Electricity Supply Tracker

Colstrip Unit 4 Generation Asset
Variable Cost/Adjustment

Dave Gates Generating Station
Variable Cost/Credit Adjustments

Spion Kop Wind Generation
Variable Cost/Adjustments

July 1, 2013 to June 30, 2014

NorthWestern Energy

May 31, 2013

Ms. Kate Whitney
Administrator, Regulatory Division
Montana Public Service Commission
1701 Prospect Avenue
PO Box 202601
Helena, MT 59620-2601

RE: D2013.5.33 – NorthWestern Energy's Electricity Supply Tracker, Colstrip Unit 4 Variable Cost/Credit True-up, Dave Gates Generating Station Variable Cost/Credit True-up, Spion Kop Variable Costs True-up Filing

Dear Ms. Whitney:

Pursuant to Montana law, the Montana Public Service Commission ("MPSC" or "Commission") rules, the Deferred Accounting Electric Procedure approved by the Commission in Order No. 6382c in Docket No. D2001.10.144 on June 26, 2002, Order No. 6943a in Docket D2008.8.95, Order No. 6925f in Docket D2008.6.69, and Order No. 7159i in Docket D2011.5.41, NorthWestern Energy ("NWE" or "NorthWestern") hereby transmits an original and ten copies of its annual Application for approval of electric supply rates which:

- Reflects rate treatment for the net balance in the Electric Supply Deferred Cost Account for the 12-month period ending June 30, 2013, including electricity supply costs, Colstrip Unit 4 ("CU4") variable costs/credits, and the Dave Gates Generating Station ("DGGS") variable costs/credits;

- Reflects the projected load, supply, and related electricity supply costs for the 12-month tracker period July 1, 2013 through June 30, 2014;

- Reflects the projected load and CU4 variable costs for the 12-month period July 1, 2013 through June 30, 2014;

- Reflects the projected load and DGGS variable costs for the 12-

month period July 1, 2013 through June 30, 2014; and

- Reflects the projected load and Spion Kop variable costs for the 12-month period July 1, 2013 through June 30, 2014.

This filing also includes:

- The CU4 fixed cost of service;
- The DGGS fixed cost of service; and
- The Spion Kop fixed cost of service.

No rate treatment is requested for these fixed cost of service items.

NorthWestern has separated this annual electric supply filing into four components:

1. Electricity Supply Tracker;
2. CU4 Generation Asset Variable Cost True-up;
3. DGGS Generation Asset Variable Cost True-up; and
4. Spion Kop Generation Asset Variable Cost True-up.

The associated separate rate components are bundled together into a single overall supply rate and net deferred cost rate for customer billing. Appendix A to the Application presents a summary of the current tariff rates and the proposed rates in this filing, as well as the resulting dollar and percentage changes.

The market-based Electricity Supply Cost section of the tracker model continues to be the updated rolling 12-month forecast.

The CU4 fixed cost revenue requirement is identical to the information provided in the past annual tracker filing and will remain the same until an order is issued in a future revenue requirement filing. The CU4 variable cost section is the updated 12-month forecast.

The DGGS fixed cost revenue requirement rate is unchanged from the May 1, 2012 monthly tracker filing reflecting Order No. 6943e in Docket No. D2008.8.95 and will remain the same until an order is issued in a future revenue requirement filing. The DGGS variable cost section is the updated 12-month forecast.

The Spion Kop fixed cost revenue requirement is unchanged from the December 1, 2013 monthly tracker filing reflecting Order No. 7159i in Docket No. D2011.5.41 and will remain the same until an order is issued in a future revenue requirement filing. The Spion Kop variable cost section is the 12-month forecast for DSM lost revenues.

The Electric Supply Deferred Cost Account Balance of $(746,835) for the period ending June 30, 2013 includes an over-collection of $(3,477,111) of electricity supply costs plus the over-collection of $(1,868,066) in the CU4 Variable Cost/Credit Account Balance offset by an under-collection of $4,598,342 in the DGGS Variable Cost/Credit account Balance.

The projected overall Electric Supply Cost and net Supply Deferred Cost in this filing result in an increase for a typical residential customer using 750 kWh per month of $0.34 per month or $4.08 per year on the total bill. This will result in an overall 0.40% increase for supply-related costs.

The typical residential bill calculation shows the combined effect of the proposed July 1, 2013 rate changes for the decreased Competitive Transition Charge for Qualifying Facilities ("CTC-QF"), and the increased BPA Residential Exchange Credit ("BPA Credit"). The total effect of the increase in the Total Electric Supply rates, along with the CTC-QF and BPA Credit rate adjustments on the typical residential customer's bill, is a projected increase of $0.03 per month or $0.36 per year.

Including all July 1, 2013 rate adjustments, the total overall bill increase for the typical residential customer is estimated to be 0.04%. The actual increase will depend on each customer's type and usage. Typical bill computations by customer class are included in Appendix B to this Application.

Other documents submitted with this filing are:

1. Application for Interim and Final Rate Adjustment, including Appendices A and B;

2. Notice of Interim Rate Adjustment Request and Certificate of Service of said notice to the media; and

3. Prefiled Testimony and Exhibits of Kevin J. Markovich, Frank V. Bennett (four components), Cheryl A. Hansen (four components), and William M. Thomas.

Three copies of this letter and documents submitted herewith are being delivered to the Montana Consumer Counsel ("MCC").

NWE's next monthly tracking filing will be for rates effective August 1, 2013, unless electricity prices move dramatically in either direction prior to June 15, 2013. If this occurs, NWE will file an updated electricity supply tracker filing for a July 1, 2013 monthly rate adjustment.

The NWE employee responsible for answering questions concerning this rate change request or for inquiries to the appropriate members of the Utility Staff is:

Joe Schwartzenberger
Regulatory Affairs Department
NorthWestern Energy
40 East Broadway
Butte, MT 59701
(406) 497-3362
joe.schwartzenberger@northwestern.com

NorthWestern's attorneys in this matter are:

Ms. Sarah Norcott
NorthWestern Energy
208 N. Montana, Suite 205
Helena, Montana 59601
Tel. (406) 443-8996
Fax (406) 443-8979
sarah.norcott@northwestern.com

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

Along with Joe Schwartzenberger, Al Brogan, and Sarah Norcott, please add Nedra Chase to the official service list in this docket to receive copies of all documents. NWE also requests that all electronic correspondence related to this filing be sent to nedra.chase@northwestern.com.

If there are any questions in this regard, I can be reached at (406) 497-3362.

Sincerely,

Joe Schwartzenberger

Joe Schwartzenberger
Director of Regulatory Affairs

Enclosures
cc: Montana Consumer Counsel

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of NorthWestern Energy's Annual Electricity Supply Tracker, Colstrip Unit 4 Generation Asset Variable Cost/Adjustment, Dave Gates Generating Station Variable Cost/Credit Adjustments and Spion Kop Wind Generation Variable Cost/Adjustments under Docket No. D2013.5.33 will be hand delivered to the PSC and MCC and e-filed with the PSC. It will also be served upon the attached service list.

Dated this 31st day of May 2013

Nedra Chase

Nedra Chase
Administrative Assistant

A. Docket D2013.5.33
Electric Tracker Service List

Al Brogan
NorthWestern Energy
208 N. Montana
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Nedra Chase
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Butte MT 59701

Robert Nelson
Montana Consumer Counsel
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Sarah Norcott
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Helena MT 59601

Joe Schwartzenberger
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Kate Whitney
Public Service Commission
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Attorneys 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 (1) Approval of Deferred Cost Account Balances for Electricity Supply, CU4 Variable Costs/Credits, DGGS Variable Costs/Credits; and (2) Projected Electricity Supply Cost Rates, CU4 Variable Rates, DGGS Variable Rates, and Spion Variable Rates	)	REGULATORY DIVISION DOCKET NO. D2013.5.33

NorthWestern Energy's Application for Interim and Final Electricity Rate Adjustment

NOW COMES, NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern" or "Applicant") by and through its undersigned counsel, and respectfully submits this Application for approval of (1) Deferred Cost Account Balances for Electricity Supply, Colstrip Unit #4 ("CU4") Variable Costs/Credits, and Dave Gates Generating Station ("DGGS") Variable Costs/Credits; and (2) projected Electricity Supply Cost Rates, CU4 Variable Rates, DGGS Variable Rates, and Spion Kop Wind Generation Asset ("Spion") Variable Rates 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
40 East Broadway
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 sheet is the only electric sheet impacted by the proposals in this submittal that is presently in effect in the State of Montana and on file with the Commission. All other electric tariff sheets remain as previously approved by the Commission:

Schedule	Description	Sheet No.
ESS-1	Electric Supply Service	60.1

The applicable rates for this tariff sheet are summarized and contained in Appendix A (attached hereto).

IV.

Applicant will submit a new tariff sheet for electric service upon approval by the Commission of the proposed rates contained in Appendix A. The proposed new rates will replace the present tariff sheet as follows:

Schedule	Description	Sheet No.
ESS-1	Electric Supply Service	60.1

V.

In accordance with the Deferred Accounting method approved by the Commission in Order No. 6382c in Docket No. D2001.10.144 on June 26, 2002, Order No. 6925f in Docket No. D2008.6.69, and Order No. 6943a in Docket No. D2008.8.95, the balance in Account No. 191, Electric Supply Deferred Costs, for the 12-month period ending June 30, 2013 is an over-collection of $(746,835). This balance consists of $(3,477,111) for the over-collection of electricity supply costs from July 1, 2012 to June 30, 2013 and $(1,868,066) for the over-collection of CU4 Variable Costs/Credits offset by an under-collection of $4,598,342 of DGGS Variable Costs/Credits. NorthWestern proposes to amortize this over-collection balance of $(746,835) in rates over the 12-month period ending June 2014. The net deferred electric supply rate per kWh is shown on Appendix A. The tracking market supply and electricity costs for the 12-month period, July 1, 2013 to June 30, 2014, produce an overall electricity supply cost per kWh as shown on Appendix A to this filing. This overall rate includes the following components: Electricity Supply Costs, CU4 Fixed Cost of Service, CU4 Variable Costs/Credits, DGGS Fixed Cost of Service, DGGS Variable Costs/Credits, Spion Fixed Cost of Service, and Spion Variable Costs/Credits. No adjustments are requested for the fixed cost of service rates.

In addition, NorthWestern proposes to continue to use the monthly tracking methodology in which a forecast of 12 months is used in this annual filing for the period July 1 through June 30 of the tracking year. Each subsequent monthly calculation is also based on a rolling 12-month forecast.

VI.

The proposed new rates contained in Appendix A reflect:

1. The treatment of the Electricity Supply Deferred Cost Account Balance, the CU4 Variable Cost/Credit Account Balance, and the DGGS Variable Cost/Credit Account Balance described in Paragraph No. V; and

2. The projected overall monthly market supply and costs—including electricity supply costs, CU4 costs, DGGS costs, and Spion costs as described in Paragraph No. V.

VII.

Attached hereto and incorporated by reference are the following documents:

- Appendix A – Current and proposed rates;
- Appendix B – Typical bill computation;
- Notice of Interim Rate Adjustment Request and the Certificate of Service of said notice to the media; and
- Prefiled Direct Testimony and exhibits of Kevin J. Markovich, Frank V. Bennett (four components), Cheryl A. Hansen (four components), and William M. Thomas.

WHEREFORE, Applicant respectfully requests that the Commission:

1. Grant interim and final approval of the proposed rates included as Appendix A to be effective on a monthly basis for service on and after July 1, 2013;
2. Grant such other and additional relief, as the Commission shall deem just and proper.

[Remainder of this page is blank – signature page to follow]

RESPECTFULLY SUBMITTED this 31st day of May 2013.

NORTHWESTERN ENERGY

By: Sarah Norcott

Sarah Norcott
Attorney for NorthWestern Corporation
d/b/a NorthWestern Energy

NorthWestern Energy
Electric Utility
Electricity Supply Costs, CU4 Fixed Cost of Service & Variable Costs\Credits,
DGGS Fixed Cost of Service and Variable Costs/Credits, Spion Kop Variable Costs,
& Deferred Electricity Supply, CU4 Variable Cost/Credit and DGGS Variable Cost/Credit
Rate Change Detail
Effective July 1, 2013

Overall Electric Supply Rate ($/kWh)	Current 6/1/2013	Proposed	Rate Change	Percentage Change
Residential	$ 0.063649	$ 0.065453	$ 0.001804	2.83%
Employee	$ 0.038189	$ 0.039272	$ 0.001083	2.84%
GS-1 Secondary Non-Demand	$ 0.059868	$ 0.061594	$ 0.001726	2.88%
GS-1 Secondary Demand	$ 0.063650	$ 0.065454	$ 0.001804	2.83%
GS-1 Primary Non-Demand	$ 0.061903	$ 0.063658	$ 0.001755	2.84%
GS-1 Primary Demand	$ 0.058555	$ 0.060240	$ 0.001685	2.88%
GS-2 Substation	$ 0.061372	$ 0.063112	$ 0.001740	2.84%
GS-2 Transmission	$ 0.061001	$ 0.062732	$ 0.001731	2.84%
Irrigation	$ 0.059868	$ 0.061594	$ 0.001726	2.88%
Lighting	$ 0.059868	$ 0.061594	$ 0.001726	2.88%

Net Deferred Electric Supply Rate ($/kWh)	Current 6/1/2013	Proposed	Rate Change	Percentage Change
Residential	$ 0.001232	$ (0.000126)	$ (0.001358)	-110.23%
Employee	$ 0.000739	$ (0.000076)	$ (0.000815)	-110.28%
GS-1 Secondary Non-Demand	$ 0.001233	$ (0.000126)	$ (0.001359)	-110.22%
GS-1 Secondary Demand	$ 0.001233	$ (0.000126)	$ (0.001359)	-110.22%
GS-1 Primary Non-Demand	$ 0.001200	$ (0.000123)	$ (0.001323)	-110.25%
GS-1 Primary Demand	$ 0.001200	$ (0.000123)	$ (0.001323)	-110.25%
GS-2 Substation	$ 0.001189	$ (0.000121)	$ (0.001310)	-110.18%
GS-2 Transmission	$ 0.001183	$ (0.000122)	$ (0.001305)	-110.31%
Irrigation	$ 0.001233	$ (0.000126)	$ (0.001359)	-110.22%
Lighting	$ 0.001233	$ (0.000126)	$ (0.001359)	-110.22%

	A	B	C	D	E	F	G	H	I	J	K
1											
2	NorthWestern										
3											
4	Energy										
5											
6	Typical Bill Calculation										
7											
8											
9	Electric Residential Service							*CTC-QF, BPA-Credit and Overall Electric Supply			
10					*Current Rates*			[1] *Proposed Rates*			
11		**kWh per month**	**750**		**Date**			**Date**			
12					**Effective**	Total Bill		**Effective**	Total Bill		
13					**6/1/2013**	Amount		**7/1/2013**	Amount		
14	Res. Dist.-Service Charge				$ 5.25	$ 5.25		$ 5.25	$ 5.25		
15											
16	Plus:										
17	Res. Supply-Energy				$ 0.063649	$ 47.74		$ 0.065453	$ 49.09		
18	Res. Deferred Supply Costs				$ 0.001232	$ 0.92		$ (0.000126)	$ (0.09)		
19	Res. CTC-QF				$ 0.003384	$ 2.54		$ 0.003350	$ 2.51		
20	Res. Transmission-Energy				$ 0.009188	$ 6.89		$ 0.009188	$ 6.89		
21	Res. Distribution-Energy				$ 0.028601	$ 21.45		$ 0.028601	$ 21.45		
22	Res. USBC				$ 0.001334	$ 1.00		$ 0.001334	$ 1.00		
23	Res. BPA-Credit				$ (0.000818)	$ (0.61)		$ (0.001187)	$ (0.89)		
24	Total Kwh Charge				$ 0.106570	$ 79.93		$ 0.106613	$ 79.96		
25											
26	**Total Bill**				**$ 0.113570**	**$ 85.18**		**$ 0.113613**	**$ 85.21**		
27											
28						Monthly Increase (Decrease)			$ 0.03		
29						Annual Increase (Decrease)			$ 0.36		
30						**Percent Change**			**0.04%**		
31											
32											
33											
34	[1]**Column represents the proposed rate changes for CTC-QF, BPA Credit, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2013.**										

	A	B	C	E	F	H	I
1							
2	NorthWestern Energy						
3							
4							
5							
6	Typical Bill Calculation						
7							
8	General Service - Secondary						
9	Non-Demand						
10						CTC-QF and Overall Electric Supply	
11				*Current Rates*		[1] *Proposed Rates*	
12		**kWh per month**	**3500**	**Date**		**Date**	
13				**Effective**	Total Bill	**Effective**	Total Bill
14				**6/1/2013**	Amount	**7/1/2013**	Amount
15	GS-1 Dist.-Service Charge			$ 7.40	$ 7.40	$ 7.40	$ 7.40
16							
17	Plus:						
18	GS-1 Supply-Energy			$ 0.059868	$ 209.54	$ 0.061594	$ 215.58
19	GS-1 Deferred Supply Costs			$ 0.001233	$ 4.32	$ (0.000126)	$ (0.44)
20	GS-1 CTC-QF			$ 0.003384	$ 11.84	$ 0.003350	$ 11.73
21	GS-1 Transmission-Energy			$ 0.007999	$ 28.00	$ 0.007999	$ 28.00
22	GS-1 Distribution-Energy			$ 0.037043	$ 129.65	$ 0.037043	$ 129.65
23	GS-1 USBC			$ 0.001143	$ 4.00	$ 0.001143	$ 4.00
24	Total Kwh Charge			$ 0.110670	$ 387.35	$ 0.111003	$ 388.52
25							
26	**Total Bill**			**$ 0.112790**	**$ 394.75**	**$ 0.113120**	**$ 395.92**
27							
28					Monthly Increase (Decrease)		$ 1.17
29					Annual Increase (Decrease)		$ 14.04
30					**Percent Change**		**0.30%**
31							
32							
33	[1]**Column represents the proposed rate changes for CTC-QF, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2013.**						

	A	B	C	E	F	H	I
1							
2–4	NorthWestern Energy						
5							
6	Typical Bill Calculation						
7							
8–9	General Service - Secondary Demand						
10						CTC-QF and Overall Electric Supply	
11		Kw	11	*Current Rates*		[1] *Proposed Rates*	
12		kWh per month	3500	Date		Date	
13				Effective	Total Bill	Effective	Total Bill
14				6/1/2013	Amount	7/1/2013	Amount
15	GS-1 Dist.-Service Charge			$ 9.25	$ 9.25	$ 9.25	$ 9.25
16							
17	Plus:						
18	GS-1 Supply-Energy			$ 0.063650	$ 222.78	$ 0.065454	$ 229.09
19	GS-1 Deferred Supply Costs			$ 0.001233	$ 4.32	$ (0.000126)	$ (0.44)
20	GS-1 CTC-QF			$ 0.003384	$ 11.84	$ 0.003350	$ 11.73
21	GS-1 Transmission-Demand			$ 3.056510	$ 33.62	$ 3.056510	$ 33.62
22	GS-1 Distribution-Demand			$ 6.230629	$ 68.54	$ 6.230629	$ 68.54
23	GS-1 Distribution-Energy			$ 0.004942	$ 17.30	$ 0.004942	$ 17.30
24	GS-1 USBC			$ 0.001143	$ 4.00	$ 0.001143	$ 4.00
25	Subtotal				$ 362.40		$ 363.84
26							
27	**Total Bill**			**$ 0.106190**	**$ 371.65**	**$ 0.106600**	**$ 373.09**
28							
29					Monthly Increase (Decrease)		$ 1.44
30					Annual Increase (Decrease)		$ 17.28
31					**Percent Change**		**0.39%**
32							
33							
34	[1]**Column represents the proposed rate changes for CTC-QF, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2013.**						

	A	B	C	D	E	F	G	H	I	J	K
1											
2	NorthWestern										
3	Energy										
4											
5											
6	Typical Bill Calculation										
7											
8	General Service - Primary										
9	Non-Demand										
10								CTC-QF and Overall Electric Supply			
11					*Current Rates*			[1] *Proposed Rates*			
12		**kWh per month**	**2000**		**Date**			**Date**			
13					**Effective**	Total Bill		**Effective**	Total Bill		
14					**6/1/2013**	Amount		**7/1/2013**	Amount		
15	GS-1 Dist.-Service Charge				$ 7.90	$ 7.90		$ 7.90	$ 7.90		
16											
17	Plus:										
18	GS-1 Supply-Energy				$ 0.061903	$ 123.81		$ 0.063658	$ 127.32		
19	GS-1 Deferred Supply Costs				$ 0.001200	$ 2.40		$ (0.000123)	$ (0.25)		
20	GS-1 CTC-QF				$ 0.003291	$ 6.58		$ 0.003259	$ 6.52		
21	GS-1 Transmission-Energy				$ 0.008368	$ 16.74		$ 0.008368	$ 16.74		
22	GS-1 Distribution-Energy				$ 0.019186	$ 38.37		$ 0.019186	$ 38.37		
23	GS-1 USBC				$ 0.001143	$ 2.29		$ 0.001143	$ 2.29		
24	Total Kwh Charge				$ 0.095091	$ 190.19		$ 0.095491	$ 190.99		
25											
26	**Total Bill**				**$ 0.099050**	**$ 198.09**		**$ 0.099450**	**$ 198.89**		
27											
28						Monthly Increase (Decrease)			$ 0.80		
29						Annual Increase (Decrease)			$ 9.60		
30						**Percent Change**			**0.40%**		
31											
32											
33	[1]**Column represents the proposed rate changes for CTC-QF, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2013.**										

	A	B	C	D	E	F	G	H	I	J	K
1											
2	NorthWestern Energy										
3											
4											
5											
6	Typical Bill Calculation										
7											
8	General Service - Primary Demand										
9											
10								CTC-QF and Overall Electric Supply			
11		Kw	400		*Current Rates*			*[1] Proposed Rates*			
12		kWh per month	200000		**Date**			**Date**			
13					**Effective**	Total Bill		**Effective**	Total Bill		
14					**6/1/2013**	Amount		**7/1/2013**	Amount		
15	GS-1 Dist.-Service Charge				$ 24.95	$ 24.95		$ 24.95	$ 24.95		
16											
17	Plus:										
18	GS-1 Supply-Energy				$ 0.058555	$ 11,711.00		$ 0.060240	$ 12,048.00		
19	GS-1 Deferred Supply Costs				$ 0.001200	$ 240.00		$ (0.000123)	$ (24.60)		
20	GS-1 CTC-QF				$ 0.003291	$ 658.20		$ 0.003259	$ 651.80		
21	GS-1 Transmission-Demand				$ 3.715008	$ 1,486.00		$ 3.715008	$ 1,486.00		
22	GS-1 Distribution-Demand				$ 4.079294	$ 1,631.72		$ 4.079294	$ 1,631.72		
23	GS-1 Distribution-Energy				$ 0.007146	$ 1,429.20		$ 0.007146	$ 1,429.20		
24	GS-1 USBC				$ 0.001143	$ 228.60		$ 0.001143	$ 228.60		
25	Subtotal					$ 17,384.72			$ 17,450.72		
26											
27	**Total Bill**				**$ 0.087050**	**$ 17,409.67**		**$ 0.087380**	**$ 17,475.67**		
28											
29						Monthly Increase (Decrease)			$ 66.00		
30						Annual Increase (Decrease)			$ 792.00		
31						**Percent Change**			**0.38%**		
32											
33											
34	**[1]Column represents the proposed rate changes for CTC-QF, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2013.**										

NorthWestern Energy

	A	B	C	D	E	F	G	H	I	J	K	L
1												
2	NorthWestern											
3												
4	Energy											
5												
6	Typical Bill Calculation											
7												
8	Irrigation & Sprinkling Service											
9	Non-Demand											
10								CTC-QF, BPA Credit and Overall Electric Supply				
11					*Current Rates*			[1] *Proposed Rates*				
12		kWh per month	1342		Date			Date				
13					Effective	Total Bill		Effective	Total Bill			
14					6/1/2013	Amount		7/1/2013	Amount			
15	Irr. Dist.-Service Charge			(a)	$ 9.03	$ 9.03		$ 9.03	$ 9.03			
16												
17	Plus:											
18	Irr. Supply-Energy				$ 0.059868	$ 80.34		$ 0.061594	$ 82.66			
19	Irr. Deferred Supply Costs				$ 0.001233	$ 1.65		$ (0.000126)	$ (0.17)			
20	Irr. CTC-QF				$ 0.003384	$ 4.54		$ 0.003350	$ 4.50			
21	Irr. Transmission-Energy				$ 0.011656	$ 15.64		$ 0.011656	$ 15.64			
22	Irr. Distribution-Energy				$ 0.023752	$ 31.88		$ 0.023752	$ 31.88			
23	Irr. USBC				$ 0.001144	$ 1.54		$ 0.001144	$ 1.54			
24	Irr. BPA Credit				$ (0.000818)	$ (1.10)		$ (0.001187)	$ (1.59)			
25	Total Kwh Charge				$ 0.100219	$ 134.49		$ 0.100183	$ 134.46			
26												
27	**Total Bill**				**$ 0.106950**	**$ 143.52**		**$ 0.106920**	**$ 143.49**			
28												
29						Monthly Increase (Decrease)			$ (0.03)			
30						Season Incr (Decr) (6 Months)			$ (0.18)			
31						**Percent Increase**			**-0.02%**			
32												
33												
34	**(a) The seasonal charge is divided by 6 months to compute a monthly average.**											
35												
36	**[1]Column represents the proposed rate changes for CTC-QF, BPA Credit, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2013.**											

NorthWestern Energy

Typical Bill Calculation

Irrigation & Sprinkling Service Demand

			Current Rates		CTC-QF, BPA Credit and Overall Electric Supply [1] Proposed Rates	
	Kw	41	Date Effective 6/1/2013	Total Bill Amount	Date Effective 7/1/2013	Total Bill Amount
	kWh per month	12260				
Irr. Dist.-Service Charge		(a)	$ 21.30	$ 21.30	$ 21.30	$ 21.30
Plus:						
Irr. Supply-Energy			$ 0.059868	$ 733.98	$ 0.061594	$ 755.14
Irr. Deferred Supply Costs			$ 0.001233	$ 15.12	$ (0.000126)	$ (1.54)
Irr. CTC-QF			$ 0.003384	$ 41.49	$ 0.003350	$ 41.07
Irr. Transmission-Demand			$ 1.999860	$ 81.99	$ 1.999860	$ 81.99
Irr. Distribution-Demand			$ 7.288016	$ 298.81	$ 7.288016	$ 298.81
Irr. Distribution-Energy			$ 0.003947	$ 48.39	$ 0.003947	$ 48.39
Irr. USBC			$ 0.001144	$ 14.03	$ 0.001144	$ 14.03
Irr. BPA Credit			$ (0.000818)	$ (10.03)	$ (0.001187)	$ (14.55)
Subtotal				$ 1,223.78		$ 1,223.34
Total Bill			**$ 0.101560**	**$ 1,245.08**	**$ 0.101520**	**$ 1,244.64**
				Monthly Increase		$ (0.44)
				Season Increase (6 Months)		$ (2.64)
				Percent Increase		**-0.04%**

(1) The seasonal charge is divided by 6 months to compute a monthly average.

[1]Column represents the proposed rate changes for CTC-QF, BPA Credit, Overall Electric Supply and Net Supply Deferred Costs effective on July 1, 2013.

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

In the Matter of NorthWestern Energy's Application For: (1) Approval of Deferred Cost Account Balances for Electricity Supply, CU4 Variable Costs/Credits, and DGGS Variable Costs/Credits; and (2) Projected Electricity Supply Cost Rates, CU4 Variable Rates, DGGS Variable Rates, and Spion Variable Rates	))))))	Docket No. D2013.5.33

NOTICE OF INTERIM RATE ADJUSTMENT REQUEST

NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern" or "NWE") serves notice pursuant to ARM 38.5.503 that it has filed with the Montana Public Service Commission ("MPSC"), via its Application, a request for an interim rate increase in electric supply rates in this Docket to reflect forecast overall Electric Supply Costs and the net Electric Supply Deferred Cost Account Balance. This Interim request includes the use of monthly electricity supply cost adjustments, annual Colstrip Unit 4 ("CU4") Variable Cost/Credit true-ups, annual Dave Gates Generating Station ("DGGS") Variable Cost/Credit true-ups and annual Spion Kop Wind Generation Asset ("Spion") Variable Cost true-ups going forward. Applicant requests that the proposed rates become effective for service on and after July 1, 2013.

This Docket commenced on May 31, 2013 when NorthWestern filed testimony and exhibits with the MPSC in its annual Electricity Supply Tracker, CU4 Variable Cost/Credit True-up, DGGS Variable Cost/Credit True-up, and Spion Kop Variable Cost True-up Filing. NorthWestern requested an interim change in rates effective July 1, 2013 pending a final decision on its Application.

The rate changes are required to: 1) reflect an increase in the projected electricity supply costs, an increase in the projected CU4 variable costs/credits, an increase in the projected DGGS variable costs/credits and an increase in the Spion variable costs; and 2) amortize the amounts in the Deferred Cost Account Balances for Electricity Supply, CU4 Variable Costs/Credits, and DGGS Variable Costs/Credits for the 12-month period ending June 30, 2013.

The net adjustments proposed in this filing result in the following:

- Overall electric supply per kWh rate increase as shown in the table below:

Overall Electric Supply Rate ($/kWh)	Current	Proposed	Rate Change	% Change
Residential	$ 0.063649	$ 0.065453	$ 0.001804	2.83%
Employee	$ 0.038189	$ 0.039272	$ 0.001083	2.84%
GS-1 Secondary Non-Demand	$ 0.059868	$ 0.061594	$ 0.001726	2.88%
GS-1 Secondary Demand	$ 0.063650	$ 0.065454	$ 0.001804	2.83%
GS-1 Primary Non-Demand	$ 0.061903	$ 0.063658	$ 0.001755	2.84%
GS-1 Primary Demand	$ 0.058555	$ 0.060240	$ 0.001685	2.88%
GS-2 Substation	$ 0.061372	$ 0.063112	$ 0.001740	2.84%
GS-2 Transmission	$ 0.061001	$ 0.062732	$ 0.001731	2.84%
Irrigation	$ 0.059868	$ 0.061594	$ 0.001726	2.88%
Lighting	$ 0.059868	$ 0.061594	$ 0.001726	2.88%

- The electric supply deferred costs balance for the 12-month period ending June 30, 2013 is an over-collection of $(746,835). This balance consists of $(3,477,111) for the over-collection of electricity supply costs from July 1, 2012 to June 30, 2013 plus the CU4 variable costs/credits over-collection of $(1,868,066) for the same time period plus the DGGS variable costs/credits under-collection of $4,598,342 for the same time period. NWE proposes to amortize the net over-collection in rates over the 12-month period ending June 2014. The resulting net electric deferred cost rates are shown below:

Net Electric Deferred Cost Rate ($/kWh)	Current	Proposed	Rate Change	% Change
Residential	$ 0.001232	$(0.000126)	$(0.001358)	(110.23)%
Employee	$ 0.000739	$(0.000076)	$(0.000815)	(110.28)%
GS-1 Secondary Non-Demand	$ 0.001233	$(0.000126)	$(0.001359)	(110.22)%
GS-1 Secondary Demand	$ 0.001233	$(0.000126)	$(0.001359)	(110.22)%
GS-1 Primary Non-Demand	$ 0.001200	$(0.000123)	$(0.001323)	(110.25)%
GS-1 Primary Demand	$ 0.001200	$(0.000123)	$(0.001323)	(110.25)%
GS-2 Substation	$ 0.001189	$(0.000121)	$(0.001310)	(110.18)%
GS-2 Transmission	$ 0.001183	$(0.000122)	$(0.001305)	(110.31)%
Irrigation	$ 0.001233	$(0.000126)	$(0.001359)	(110.22)%
Lighting	$ 0.001233	$(0.000126)	$(0.001359)	(110.22)%

The interim request and supporting documents can be examined at NorthWestern's General Office, 40 East Broadway, 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 MPSC, 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 MPSC take into consideration in its decision on this matter should be delivered to the MPSC at the above address as soon as possible or mailed to the MPSC at P.O. Box 202601, Helena, MT 59620-2601.

Any portion of the interim adjustment approved by the MPSC pending hearing and final decision would, pursuant to § 69-3-304, MCA (2011), be subject to rebate or surcharge if the final decision in this docket is to approve a final revenue level which is different than the interim level.

DATED: May 31, 2013

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

In the Matter of NorthWestern Energy's Application For: (1) Approval of Deferred Cost Account Balances for Electricity Supply, CU4 Variable Costs/Credits, and DGGS Variable Costs/Credits; and (2) Projected Electricity Supply Cost Rates, CU4 Variable Rates, DGGS Variable Rates, and Spion Variable Rates	)	Docket No. D2013.5.33

CERTIFICATE OF SERVICE
OF NOTICE OF INTERIM RATE ADJUSTMENT REQUEST
FOR ELECTRICITY SUPPLY 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	-	KECI and KPAX
Great Falls	-	KFBB and KRTV
Bozeman	-	KTVM
Helena	-	KTVH

DATED: May 31, 2013

NorthWestern Energy

By: Claudia Rapkoch

Claudia Rapkoch
40 East Broadway
Butte, Montana 59701

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.5.33
Annual Electric Supply Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF KEVIN J. MARKOVICH

ON BEHALF OF NORTHWESTERN ENERGY

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Witness Information

Q. Please state your name and business address.

A. My name is Kevin J. Markovich and my business address is 40 East Broadway, Butte, Montana 59701.

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

A. I am employed by NorthWestern Energy ("NWE" or "NorthWestern" or "Company") as Director of Energy Supply Market Operations.

Q. Please summarize your educational and employment experiences.

A. I attended Montana State University, graduating in 1983 with a Bachelor of Science degree in Business, Accounting option. Upon graduation, I went to work for Marathon Oil Company in Casper and Cody, Wyoming as a production accountant. In 1985, I enrolled at the University of Wyoming in Laramie where I earned a Master of Business Administration degree in December 1986. In 1987, I went to work in the Treasury Department of Entech, Inc., a wholly owned subsidiary of The Montana Power Company ("MPC"). In 1996, I transferred to the Montana Power Trading & Marketing Company ("MPT&M") where I worked in various capacities including real-time electric scheduler, gas marketer, and executive director of retail marketing. In 2000, prior to the sale of MPT&M to Pan Canadian, I transferred to MPC, now NorthWestern Energy, where I have worked on numerous energy supply activities. In January 2005 I became the Director of Risk Management and in September 2006 I assumed my current position.

Q. What are your responsibilities as Director of Energy Supply Market Operations?

A. I am responsible for NorthWestern's energy supply market operations including daily, weekly, monthly, and term trading and scheduling activities. This involves developing and maintaining relationships with suppliers, brokers, and other market participants; executing and managing term contracts; negotiating and approving supply arrangements that are consistent with regulatory guidelines and internal policies; and developing and implementing overall supply strategies to ensure there is adequate supply to meet demand at all times. I also provide information and testimony on utility-related matters before the Montana Public Service Commission ("Commission").

Q. Do you hold any professional certifications?

A. Yes. I am a Certified Public Accountant and a Certified Cash Manager.

<u>Purpose of Testimony</u>

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

A. My testimony is intended to provide the necessary information to satisfy the filing requirements set forth in ARM 38.5.8226(3). In my testimony, I discuss recent supply planning, supply management, and resource procurement activities and the action plan items that NorthWestern executed during the 2012/2013 tracker period. My testimony discusses the expiration of the 7-year power purchase agreement with PPL Montana, LLC ("PPL") and contrasts the current situation to that of 2006, when NWE faced a similar situation. I also discuss current and future actions that NorthWestern is taking and considering to replace this resource. My testimony then also describes the 2012/2013 tracker period activities and the 2013/2014 tracker period forecast, and, finally, I introduce the other NWE witnesses who submit testimony in this filing and briefly describe the topic(s) covered by each.

<u>NWE's Electricity Supply Resource Procurement Plans</u>

Q. Please discuss the framework that guides NWE's electricity supply planning and acquisition activities.

A. Montana's statutes and regulations guide NorthWestern's planning and acquisition decisions. See, e.g., §§ 69-8-419 through 421, MCA, and ARM 38.5.8201 through 38.5.8301.

ARM 38.5.8226(1) requires NWE to file a comprehensive long-term portfolio management and electricity supply resource procurement plan in December of odd-numbered years. NorthWestern's most recent plan was filed in December 2011 ("2011 Plan") in Docket No. N2011.12.96. The

2011 Plan is a comprehensive analysis of NWE's retail electricity load-serving obligations for its retail customers in Montana. Chapter 10 of the 2011 Plan identifies and discusses key initiatives and baseline activities that will be addressed by NorthWestern during the three-year action plan period. As initiatives and baseline activities progress, NWE communicates the results of these activities to the Commission and stakeholders. The descriptions of the action items in the 2011 Plan illustrate the transparent processes that NWE employs to apprise the Commission and other parties of the scope and focus of its resource planning and acquisition activities.

As described and demonstrated in this annual electric tracker filing, the supply portfolio is composed of a diverse set of resources in terms of resource type, duration of delivery, and generation ownership. The electricity supply portfolio has evolved over time to include a mixture of market products, contracted and owned generation resources, and resources fueled by a range of fuel types including coal, natural gas, hydro, and wind.

Q. Please describe NorthWestern's electricity supply resource plans and their relationship to its procurement activities.

A. Since 2003, NWE has produced and filed five biennial electricity supply procurement plans ("Plans"). The Plans, and the accompanying

Commission and stakeholder comments, provide guidance to the resource planning and acquisition processes that NWE follows in order to cost-effectively and reliably meet its retail load-serving obligations. Energy and resource procurement is a dynamic process because of changing needs, changes in market conditions, and other variables that NorthWestern must consider as it works to balance the costs and risks of electricity supply alternatives.

Action Plan

Q. What has NWE done regarding the action items that were identified and discussed in the 2011 Plan?

A. Below is a list of the initiatives and the baseline activities enumerated in the 2011 Action Plan along with an update of related accomplishments that took place during the 2012/2013 tracker period:

Initiatives

1. *Identify, consider, and procure, if available, electric generation assets that meet acceptable levels of portfolio energy, cost and risk.*

   NorthWestern has had a continuing dialogue with developers to discuss generation assets and opportunities, and through these efforts many new generation resources have become available to NorthWestern (see actual resources listed below under Baseline Activities). In addition, a Request for Proposals ("RFP") for

Community Renewable Energy Projects ("CREP') was issued during the 2012/2013 tracker period which could result in more renewable generation becoming available to NorthWestern.

2. *Replace the existing electricity supply contracts (including the volumes associated with the PPL 7-year agreement) set to expire in the 2013-2014 timeframe with new, 3- to 5-year staged market-based supply contracts and/or utility owned generation assets.*

See the section of testimony below describing actions taken in anticipation of the expiration of the 7-year power purchase agreement with PPL.

3. *Refine analysis associated with gas-fired generation technology including the evaluation of costs, resource flexibility, and portfolio needs.*

NorthWestern's Generation Department is conducting site analysis and generation scoping work in an effort to determine site-specific locations and generation resources that have the operational characteristics best suited to meet the needs of the electric supply portfolio. This work is expected to be completed in the 2013/2014 tracker period, and the results will be published in the 2013 Plan.

4. *Evaluate options to define resource adequacy standards including specific resource attributes and load serving capabilities.*

Work on this initiative has begun, and in the 2013 Plan NorthWestern will describe the long-term process to define and evaluate the resource adequacy of its supply portfolio. This process will allow NWE to better assess its portfolio needs and further clarify additional generation resources that are available to complement existing resources.

5. *Improve the strategies and methods associated with integrating intermittent resources including wind power.*

NorthWestern, consistent with objectives included in the 2011 Plan, continues to study the impacts of variable wind generation on its integration and portfolio operations. This effort will be expanded to evaluate actual operational issues associated with the 60 MW of wind generation that was added to the supply portfolio in late 2012 and in turn better define the benefits and/or difficulties associated with intermittent resources.

Baseline Activities

1. *Meet the Renewable Portfolio Standard ("RPS") consistent with Montana statutes.*

Since its 2011 Plan, NorthWestern has expanded its RPS eligible CREP contracts from 13 megawatts ("MW") to 23.05 MW and has increased its potential RPS eligible contracts from 148 MW to 239

MW with an additional 22 MW pending regulatory review and certification.

2. *Add new electricity supply resources to the portfolio (including Spion Kop and QFs).*

NorthWestern has added the following long-term resources to its supply portfolio, all of which are operational except Two Dot Wind Farm LLC and Fairfield Wind LLC which are expected to become operational in late 2013:

Project	Nameplate Capacity
• Spion Kop	40 MW
• Musselshell Wind Project LLC	10 MW
• Musselshell Wind Project Two LLC	10 MW
• Two Dot Wind Farm LLC	9.72 MW
• Gordon Butte Wind LLC	9.6 MW
• Fairfield Wind LLC	9.5 MW
• Flint Creek Hydroelectric LLC	2.0 MW
• Lower South Fork LLC	0.445 MW

3. *Acquire cost-effective Demand Side Management ("DSM").*

NorthWestern has continued its ongoing efforts to acquire all cost-effective DSM resources, and an independent evaluation of its program efforts has been completed. The results of this evaluation will inform development of the DSM section of the 2013 Plan.

4. *Monitor the following areas:*
    a. *Regional energy markets, including ancillary services markets;*
    b. *Regulation of emissions from existing and future electric generation plants;*
    c. *Electricity supply technology advancements, and*
    d. *Regulatory changes to supply and planning rules.*

NorthWestern has been actively monitoring issues and participating in regional groups that affect the markets and environment in which the Company operates. NWE is an original member of the Intra-Hour Transaction Accelerator Platform ("I-TAP") group and currently serves on its technical steering committee. I-TAP began as a Columbia Grid initiative by utilities in the western United States to make intra-hour trading easier and more efficient. In addition, NWE is monitoring and analyzing developments and initiatives regarding energy imbalance markets in the Northwest and the implementation of FERC Order No. 764. NWE is also ensuring compliance with Dodd-Frank reporting requirements through the Commodity Futures Trading Commission ("CFTC").

NWE is also closely following the changes to supply and demand that are occurring in Montana and elsewhere in the region. Among these changes are the announced mothballing of PPL's J.E. Corette Power Plant, planned shut-downs of other coal-fired plants in the region, and the pending completion of the Montana-Alberta Tie-Line.

<u>NWE's Supply Portfolio</u>

Q. Briefly discuss NWE's recent activities that have been performed to manage the supply portfolio.

A. During the 2012/2013 tracker year NWE accomplished the following:

- Continued to execute market purchases to meet near-term load-serving needs. Favorable market conditions have resulted in attractive pricing for products purchased in the hourly, day-ahead, and short-term markets. NWE has continued to use market purchases and products to reliably meet customer energy demands while effectively managing price and limiting customer risk.
- Continued to implement the DSM plan included and described in the 2011 Plan with the goal of achieving 6 average MW of incremental energy savings capability annually. NWE continued its deliberate and aggressive plan to help customers install energy conservation measures as outlined in the 2011 Plan through voluntary programs using both internal and external resources (contractors) to achieve annual targets. Please see the Prefiled Direct Testimony of William M. Thomas for detail about NWE's DSM implementation.
- Satisfied the RPS requirement for compliance year 2012 as prescribed in § 69-3-2004(3)(a), MCA. During 2012 and 2013, NWE purchased

bundled electricity and renewable energy credits (“RECs”) from eligible projects located in Montana including Gordon Butte (wind), Judith Gap (wind), Turnbull (hydro), Spion Kop (wind), Musselshell (wind), Musselshell II (wind), and Lower South Fork (hydro). Using RECs carried over from previous years and a portion of the RECs from 2013 renewable production, NWE retired 592,007 RECs from its Western Renewable Energy Generation Information System account to satisfy its 2012 RPS obligation. NWE has 137,388 of surplus RECs that will be carried over to meet future RPS obligations.

PPL 7-Year Contract Expiration

Q. Describe and contrast the pending expiration of the current 7-year supply contract with PPL with the similar situation NWE faced in 2006.

A. In 2006 NWE faced the unenviable situation of having a single electric supply contract with PPL, representing more than 54% of yearly supply needs, set to expire in June 2007. At that time, market prices were substantially higher than the fixed-price terms in the existing contract, causing concern about rate shock to customers. Compounding the situation was the financial condition of NWE, recently emerged from bankruptcy with its credit rating still not investment grade. That 2006 situation was commonly referred to as the “cliff.” In the end NWE bilaterally negotiated a 7-year, fixed-price supply contract with PPL that contained declining volumes and a smoothing-in of market prices. This contract is currently in place but expires on June 30, 2014.

In comparison, the situation today is much less onerous. In 2006 the PPL contract represented 3.4 million megawatt-hours ("MWh") per year; the current PPL contract is less than 1.5 million MWh per year. Since 2006 NWE has procured approximately 1.7 million MWh through competitive solicitations resulting in contracts that extend beyond the expiration of the PPL contract. And, NWE has an additional 1.0 million MWh of yearly supply from rate-based assets that were not available seven years ago. Finally, market prices are 25-30% lower than those in the current PPL contract, and if this continues, customer rates equivalent to the current PPL volume will decline once the PPL contract expires.

In 2006 the options for replacing the PPL supply contract were very limited; today, because of a disciplined and structured procurement program and the development of the energy supply function, NWE has more opportunities and structures that can be utilized. The main differences include the following:

- The Company no longer needs to rely on a single supplier to meet its physical and financial needs;

- The Company's improved financial condition allows transactions with an array of counterparties who previously were not interested because of NWE's credit situation;
- The real-time scheduling function brought in-house in 2009 gives NorthWestern the skills and flexibility to move energy from other areas and markets and allows better utilization of shorter-term markets; and
- NWE's market knowledge, risk management, and contracting capabilities have expanded, allowing the Company to separate the physical procurement of supply from the hedging aspect.

The key to replacing the PPL contract, as well as the key to managing the entire supply portfolio, is to effectively balance the short- and long-term needs of customers. In doing so, the Company must continue to implement NWE's formalized energy supply planning process, be cognizant of the opportunities to purchase or develop long-lived assets, and be constantly aware of market fundamentals that affect forward market prices. The portfolio management process must be flexible and able to adapt as changes and developments occur.

Below are some of the specific steps NorthWestern has either taken or expects to take in anticipation of the PPL contract expiring on June 30, 2014:

- Initiated fixed-price energy purchases at Mid C for Quarter 3 and Quarter 4 2014 to serve as a hedge, utilizing brokers and bilateral negotiations in order to balance supply needs on a calendar-year basis.
- Commenced preliminary discussions with PPL regarding future supply needs. As has been the case over the past several years, NWE has indicated a preference to purchase on-system, physical energy based on market or index prices.
- Issued a competitive solicitation on May 13, 2013 seeking energy for the second half of 2014 and calendar years 2015, 2016, and 2017. Offers were requested for energy delivered at either Mid C or the NWE system, fixed-price or index-based, and both on-peak and off-peak.
- If the May 2013 competitive solicitation proves successful and circumstances have not changed, another solicitation will be issued sometime in late 2013 or early 2014, and competitive solicitations will continue to be issued as long as there is a need for energy in future years.

<u>2012/2013 Tracker Period Activities</u>

Q. What planning document guided electricity supply procurement and scheduling activities during the 2012/2013 tracker period?

A. The Hedging Strategy that is Appendix 1 of the 2011 Plan is the document that primarily guided electricity supply procurement activities during the 2012/2013 tracker period.

Q. Please provide an overview of the 2012/2013 tracker period.

A. As detailed in the Prefiled Direct Testimony of Frank V. Bennett ("Bennett Direct Testimony"), the 2012/2013 tracker period contained no material operational changes or issues that caused supply service to change from the previous tracker period. Market prices have remained low compared to the pre-recession era, and through the flexibility provided by the Hedging Strategy, NWE has been able to take advantage of this by procuring more energy in the day-ahead and hourly markets.

Q. Did NWE make any longer-term energy market purchases during the 2012/2013 tracker period?

A. Yes. NWE procured an additional 25 MW of index-priced, on-system energy for the period of December 2012 through May 2014. In addition, as I described earlier in my testimony, a competitive solicitation is currently being conducted.

Q. Did NWE meet an acceptable prudency standard in providing its energy supply service during the 2012/2013 tracker period?

A. Yes. NWE managed its energy supply portfolio in a systematic, structured manner with specific measures and timelines that provided a guided, disciplined approach to energy procurement. The Hedging Strategy goals are designed to maintain reasonable rates while dampening volatility and enhancing price stability. During the tracker period, NWE did not speculate on energy price movements and therefore did not subject customers to unnecessary risk. NWE adhered to its 2011 Plan which provides a framework by which the prudence of NWE's procurement activities can be judged and will continue to do so.

Furthermore, electricity service was never interrupted or restricted at any point during this period due to actions or inactions of NorthWestern's energy supply function. NWE did not receive any fines or penalties from oversight authorities regarding scheduling or operating performance. All contracts were properly scheduled, administered, checked out, and paid according to the terms and conditions. And, as described above, NWE followed a logical and prudent strategy for procuring energy which resulted in reasonable rates and reduced exposure to market price volatility for customers.

2013/2014 Tracker Period Forecast

Q. Please comment on the 2013/2014 tracker period forecast.

A. Again, the Bennett Direct Testimony provides a detailed forecast of the upcoming tracker period. It should be noted that this is merely a forecast using information that is known at this time; actual results will vary somewhat and will be based on actual transactions and prices.

The Hedging Strategy in the 2011 Plan will guide scheduling and procurement activities for the 2013/2014 tracker period until such time as NWE files its 2013 Plan. After that point, NWE will follow the Hedging Strategy in the 2013 Plan, guided by comments received from the Commission. NWE will adhere to these Plans unless a fundamental change occurs in the market or an opportunity presents itself that is not contemplated in the Plans. During this time NWE will continue to look for additional buying opportunities and search for other products and transactions that create value and efficiencies for the benefit of customers.

Once again, NWE will continue to utilize a systematic, disciplined approach to energy supply procurement, and it will continue to inform stakeholders of noteworthy changes and developments.

Introduction of Other Witnesses

Q. Please introduce the other witnesses in this filing.

A. In addition to my testimony, this electric tracker filing includes the prefiled direct testimonies of the following:

- Frank V. Bennett, Contract and Regulatory Specialist. Mr. Bennett presents the following information:
    - o Updated 12-month ended June 2013 electricity supply costs, Colstrip Unit 4 ("CU4") variable costs/credits, and

Dave Gates Generating Station (“DGGS”) variable costs/credits;
    - The forecasted 12-month ended June 2014 information for each of the segments listed above and for the Spion Kop Wind Generation Project (“Spion”).

- Cheryl A. Hansen, Senior Analyst in the Regulatory Affairs Department. Ms. Hansen offers testimony that:
    - Presents the 2013/2014 tracker year billing statistics and explains how they are derived;
    - Presents the derivation of proposed deferred electricity supply rates resulting from the over/under collection reflected in the 2012/2013 periods for electricity supply costs, CU4 variable costs, and DGGS variable costs;
    - Presents the derivation of proposed electricity supply cost rates, CU4 variable rates, DGGS variable rates and Spion variable rates for the forecasted 2013/2014 tracker period; and
    - Presents the all-in electricity supply rates incorporating all individual variable and fixed rate components.

- William M. Thomas, Manager Regulatory Support Services. Mr. Thomas offers testimony that:

- Presents a review of the Electric Supply DSM energy efficiency programs administered by NorthWestern for Tracker Year 2012/2013 and the results from the Universal System Benefits program for the same period;
- Provides updated numbers for DSM Program costs and associated lost revenues for Tracker Year 2012/2013; and
- Provides forecasted numbers for DSM Program costs and associated lost revenues for Tracker Year 2013/2014.

Q. Does this conclude your testimony?

A. Yes, it does.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.5.33
Annual Electric Supply Filing
NorthWestern Energy

PREFILED DIRECT TESTIMONY
OF WILLIAM M. THOMAS
ON BEHALF OF NORTHWESTERN ENERGY

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Exhibits

Witness Information

Q. Please state your name and business address.

A. My name is William M. Thomas, and my business address is 40 East Broadway, Butte, Montana 59701.

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

A. I am employed by NorthWestern Energy ("NorthWestern" or "NWE") as Manager of Regulatory Support Services in the Government and Regulatory Affairs Department.

Q. Please state your educational background, experience and responsibilities.

A. I graduated from Montana State University with a Bachelor of Science degree in Science and Education. I was employed by The Montana Power Company ("MPC") from 1980-1999 in a variety of staff and management positions. During that tenure, I served as Program Director for MPC Demand Side Management ("DSM") Programs for Residential and Commercial customers. I attended the Public Utility Executives Program at the University of Idaho in 1991. I joined NorthWestern in April 2004 in the capacity of DSM Program Coordinator and assumed my present position as Manager of Regulatory Support Services in April 2005. In addition to other departmental activities related to support of regulatory filings and proceedings, I am responsible for providing overall coordination and direction on development, implementation, and promotion/education of DSM programs and interaction with the Technical Advisory Committee on DSM matters. My duties also include preparing the information supporting NorthWestern's DSM-related activities and proposals in this filing.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I testify to the following:

1. Results from Universal System Benefits ("USB") and Electric Supply DSM energy efficiency programs conducted by NorthWestern for Tracker Year 2012-2013 and a description of the status of and plans for DSM programs and related activities in the forthcoming tracker period; and

2. Updated numbers for the DSM Program costs and the Lost Revenue Recovery Mechanism for recovery of Electric Supply DSM Program costs and historical lost transmission, distribution, Colstrip Unit #4 ("CU4"), Dave Gates Generating Station ("DGGS"), and Spion Kop Wind Generating Facility ("Spion") revenues ("Lost Revenues") associated with Electric Supply DSM and USB programs, as well as forecasted information.

2012-2013 Program Results

Q. Please describe the overall results of USB and Electric Supply DSM energy efficiency program activities in the 2012-2013 electric supply tracker period.

A. In the 2004-2005 time period, NorthWestern established a DSM Acquisition Plan with DSM goals set at the level of 2.6 aMW of installed energy savings capability in Program Year 1 (2004-2005 Tracker Year), ramping up to 3.7 aMW in Program Year 2 (2005-2006), and then to 5.0 aMW in Program Year 3 (2007-2008 Tracker Year) and leveling at 5.0 aMW each year through 2009-2010. In its 2009 Electric Default Supply Procurement Plan, NorthWestern increased its annual DSM goal to 6.0 aMW starting in the 2010-2011 time period. Table 1 below summarizes the annual targets, reported energy savings, budget, and spending for the 2004-2013 tracker periods.

Table 1: DSM Targets, Reported Savings, Budget and Spending

Program Year	Tracker Period	Installed Annual DSM Capability (Incremental)				Electric Supply DSM Tracker Budget ($)	Electric Supply DSM Program Expenditures ($)
		Target (aMW)	Reported Program Results (aMW)[1]				
			USB	DSM	Total		
1	2004-05	2.60	2.04	0.22	2.26	$1,457,888	$ 320,389
2	2005-06	3.70	1.33	2.08	3.41	$2,097,734	$1,596,076
3	2006-07	5.00	0.36	3.04	3.40	$3,232,080	$2,497,359
4	2007-08	5.00	0.82	4.55	5.37	$3,631,683	$3,688,745
5	2008-09	5.00	1.11	5.58	6.69	$4,917,141	$5,504,111
6	2009-10	5.00	0.96	7.37	8.33	$6,625,192	$7,652,658
7	2010-11	6.00	0.55	8.01	8.56	$9,148,219	$7,108,435
8	2011-12	6.00	0.45	8.87	9.32	$8,063,519	$9,185,261
9	2012-13	6.00	0.38	6.70	7.08	$10,441,871	$11,972,701
10	2013-14	6.00				$9,618,958	

[1] Values for Program Year 7 (2010-11) and Year 8 (2011-12) have been updated to reflect 12 months of actual data for reported energy savings and program spending.

Work to prepare the annual tracker begins in April of each year with a planned filing date of June 1. This schedule requires estimation of DSM energy savings and program costs for a portion of the end of the current tracking period.

The Electric Supply DSM Program Expenditures for DSM Program Year 9 (2012-2013) in Table 1 are based on 10 months of actual costs and 2 months (May-June 2013) of estimated expenses. The estimated amount of 7.08 aMW of incremental new installed DSM capability is based on 9 months of actual and 3 months (April, May and June 2013) of estimated program activity.

The annual aMW targets and reported savings are comprised of amounts of installed annual energy savings capability contributed from measures and actions implemented under both USB Programs and Electric Supply DSM Programs. The Reported Program Results represent the capability of installed conservation and efficiency measures to produce energy savings for a full year. Although energy savings produced by USB Programs are counted toward the overall annual aMW target and included in calculations of DSM Lost Revenues, USB Programs are funded through a separate charge and USB spending is not reported or included in Table 1.

Q. Please provide additional details on energy savings of individual USB and DSM Programs in operation during the 2012-2013 Tracker Year.

A. Exhibit__(WMT-1) provides individual program details on reported energy savings and develops numbers used in the updated DSM Lost Revenues computation. This exhibit presents the following two tables of tabulation and analysis:

1. Table A: Reported Electricity Savings from 2012-2013 USB and DSM Program Activity.

The data presented in this table represents summarized results for reported energy savings for programs and projects for the tracker period July 2012 through March 2013. Reported energy savings means estimates of electricity savings from either individual projects, where engineering calculations were submitted with project proposals and reviewed by NorthWestern staff for specific energy conservation projects (e.g., E+ Commercial Lighting projects, Business Partners site-specific projects, or Renewable Generation projects), or in those cases where engineering calculations are not required for program participation, average energy savings per DSM measure (also referred to as *deemed savings*) are used. Examples of this include residential and commercial audits and variable frequency motor drives. Reported energy savings represent the annual energy savings that would occur if all energy savings measures were in place for a full 12 months.

For the final three months of the 2012-2013 tracker period (April - June 2013) estimates of energy savings were made based on previous program experience, pending applications for rebates and incentives, pending project proposals, and discussions with outside service providers assisting NorthWestern with USB and DSM program operation.

2. Table B: Residential and Commercial Electric Savings for Calculation of Lost Transmission & Distribution Revenues.

Consistent with previous years, NorthWestern's proposal for DSM cost recovery in tracker period 2012-2013 includes calculations for DSM Lost Revenues. Because the applicable transmission, distribution, CU4, DGGS, and Spion rates used to compute those Lost Revenues are different for NorthWestern's residential and commercial customers, it is necessary to estimate the percentage split between residential and commercial DSM resources that were acquired in the 2012-2013 Program Year. Table B identifies portions of each USB and DSM program attributable to residential and commercial projects and/or customer participants and then develops a straightforward summing of the estimated residential and commercial program electricity savings from Table A to produce the overall percentage contribution by the residential (50.99%) and commercial (49.01%) customer classes to the total. These percentage splits are then used as inputs to the calculation of Lost Revenues (e.g., see page 3, lines 17-18 of Exhibit__(WMT-3)).

DSM Program Status Report

Q. What is the current status of electric supply DSM programs and what actions are planned for the 2013-2014 tracker year?

A. NorthWestern intends to continue offering a full portfolio of programs to its customers in the forthcoming 2013-2014 tracker period. The results of the SBW Consulting, Inc. ("SBW") DSM Program Evaluation provide useful information that helps NorthWestern make appropriate changes and course corrections to the existing programs to facilitate continued steady acquisition of cost-effective DSM resources. Exhibit__(WMT-2) presents DSM spending by program for 2012-2013 (actual through April 2013, estimates for May-June 2013) and estimated spending for Tracker Year 2013-2014.

The following is an update of DSM program activities and future plans:

1. <u>E+ Lighting Programs</u>: KEMA Services, Inc. ("KEMA") provided lighting program implementation services for both commercial and residential customers in the 2012-2013 tracker period. Through KEMA, NorthWestern offered cash rebates for ENERGY STAR® qualified compact fluorescent lamps ("CFLs") and indoor/outdoor fixtures. The program included several mechanisms to either distribute or encourage purchase and use of ENERGY STAR® CFLs and fixtures, including:
    a. Direct installation of CFLs in homes during home energy audits and commercial appraisals;

b. Free CFL with mail-in home audits;

c. Mail-in rebates for residential customers for CFLs and ENERGY STAR® fixtures;

d. Rebates to commercial customers for energy efficient lighting equipment and controls;

e. In-Store Instant Rebates with redeemed coupons;

f. Simple Steps Program – buy-down of CFL prices at retailers through a regional campaign facilitated by the Bonneville Power Administration; and

g. Non-Retailer Special Events (trade shows, fairs, Farmers Markets, Energy Expos, etc.).

New federal regulations relating to energy efficiency standards for lighting technologies began phasing in over a three-year period starting January 1, 2012. These new regulations apply to manufacturing of lighting products, not to retail sale of them. Regardless of whether manufacturers have ceased production of targeted lighting products as a result of the unenforced regulations, remaining stock of lighting products (e.g., incandescent bulbs) will continue to be sold and installed by consumers for perhaps a year or more following the effective dates of the new regulations for each respective lighting product. Energy savings opportunities remain during this interim period while retailers' lighting stock clears of incandescent lighting products. During this stock clearing period, if consumers can be persuaded through NorthWestern's E+ Lighting Rebate programs to purchase CFLs or other lighting technologies instead of the less efficient bulbs (which will eventually be eliminated by the new regulations), then low-cost DSM resources will be acquired in the same manner as in the past – through operation of the E+ Lighting Rebate programs.

A 100-watt incandescent lamp itself is not a qualified DSM program measure but replacement of a 100-watt lamp with a 23-watt CFL is a qualified DSM measure. Incandescent lamps of 100 watts, 75 watts or 60 watts are typically replaced with CFLs in ranges of size shown in Table 2.

Table 2: CFL Replacements for Incandescent Lamps

To Replace		
Incandescent Bulb Rating (Watts)	Necessary Light Output (lumens)	Typical CFL Replacement (Watts)
40 Watts	450	9-13 Watts
60 Watts	800	13-15 Watts
75 Watts	1,100	18-15 Watts
100 Watts	1,600	23-30 Watts
150 Watts	2,600	30-52 Watts

Source: http://www.energystar.gov/index.cfm?c=lighting.pr_lighting_landing

CFLs of 23 watts (or larger) are commonly used to replace 100-watt incandescent bulbs. In the past NorthWestern calculated the energy savings in this case as the wattage differential between the baseline lamp and the replacement lamp (e.g., 100 watts – 23 watts = 77 watts) multiplied by the assumed daily burn hours. Beginning January 1, 2013 NorthWestern modified its assumption for the baseline lamp from 100 watts to 75 watts for CFLs within the 23-30 watt range shown as typical replacements for 100-watt incandescent bulbs in Table 2 above. Beginning January 1, 2014 this baseline lamp assumption will be further reduced to 60 watts as supplies of higher wattage incandescent lamps become increasingly scarce due to the phased-in federal regulations. Beyond 2014, it is likely that NorthWestern's CFL rebate programs will be discontinued entirely unless regulations change.

NorthWestern renewed its contract with KEMA for services related to the E+ Lighting Programs and will offer these programs again in 2013-2014.

2. <u>E+ Commercial DSM Programs and Contractors</u>: NorthWestern has taken additional steps to increase its capability to acquire commercial sector DSM. Three firms have renewed two-year contracts to provide services in support of the E+ Business Partners Program, the E+ Commercial Lighting Rebate Program, the E+ Commercial Electric Rebate Program for New Construction, and the E+ Commercial Electric Rebate Program for Existing Facilities. There are currently five firms concentrating on the commercial and small industrial sectors:

- CTA Associates, Inc.
- Energy Resource Management, Inc.
- McKinstry Essention
- Portland Energy Conservation, Inc.
- National Center for Appropriate Technology ("NCAT")

All of these contractors are compensated by NorthWestern on a performance basis, with payment based on a percentage of the energy conservation resource value of each individual DSM project that is completed with the contractor's involvement. All contractors are expected to deliver to NorthWestern an estimated 0.25 aMW of incremental DSM each year.

These contractors are supported by a four-member team of KEMA employees who have responsibility for direct contact, face-to-face marketing of DSM programs to commercial/small industrial customers in an effort to identify, qualify, and cultivate DSM projects for follow-up by the contractors listed above. Services provided by these contractors include marketing to architect/engineering firms and trade/industry associations in Montana, direct contact with candidate businesses with DSM potential, surveys and assessments of buildings and facilities, technical assistance for building owners, assistance with required engineering analysis and modeling, and assistance to customers with forms, contracts, and other paperwork used in and necessary for participation in these programs. Additional details regarding these contractors and their accomplishments to date are as follows:

CTA Architects & Engineers

- Second year of a two-year performance contract.
- During the 2012-2013 tracker period, the following have been or will be completed, providing an estimated 0.235 aMW of DSM:
  - Five commercial custom incentive electric conservation projects.
  - 16 commercial lighting rebate projects.
  - Two commercial electric rebate projects.

Energy Resource Management Inc.

- Second year of a two-year performance contract.
- During the 2012-2013 tracker period, the following have been or will be completed, providing an estimated 0.142 aMW of conservation:
  - One commercial custom incentive electric conservation project.
  - Nine commercial lighting rebate projects.

McKinstry Essention

- First year of a two-year performance contract.
- During the 2012-2013 tracker period, the following have been or will be completed, providing an estimated 0.152 aMW of conservation:
  - 12 commercial lighting rebate projects.
  - 12 commercial electric rebate projects.

Portland Energy Conservation Inc.

- First year of a two-year performance contract.
- During the 2012-2013 tracker period, the following have been or will be completed, providing an estimated 0.05 aMW of conservation:
  - 12 commercial electric rebate projects.

National Center for Appropriate Technology

- First year of a two-year performance contract.

- During the 2012-2013 tracker period, the following have been or will be completed, providing an estimated 1.49 aMW of conservation:
  - 12 commercial custom incentive electric conservation projects.
  - 116 commercial lighting rebate projects.
  - 26 commercial electric rebate projects.

3. Northwest Energy Efficiency Alliance ("NEEA"): NEEA is a regional non-profit organization supported by electric utilities, public benefits administrators, state governments, public interest groups, and energy efficiency industry representatives. Through regional leveraging, NEEA encourages "market transformation" or the development and adoption of energy efficient products and services in Montana, Washington, Idaho, and Oregon. NEEA's regional market transformation activities target the residential, commercial, industrial, and agricultural sectors.

NorthWestern is in year four of a five-year commitment that will continue its funding of and participation in NEEA activities and initiatives during the 2010-2014 time period. NorthWestern reported energy savings from NEEA activities totaling 0.38 aMW during the 2012-2013 tracker period. Information on NEEA's numerous projects and initiatives that were in progress during 2012-2013 and are continuing into the future can be found at http://www.nwalliance.org/.

4. E+ New Homes: NorthWestern renewed its contract with NCAT to provide services related to this program, including builder/owner education, technical assistance, marketing, and outreach. USB funds were used to market the program and educate architects, building contractors, and interested customers about ENERGY STAR® standards. NEEA funds some of the infrastructure development of ENERGY STAR® Northwest activities. In NorthWestern's Montana service area, two new electrically heated homes were certified in 2012-2013 and 51 new natural gas heated homes. Current code requires 50% high efficiency lighting, but as a direct result of NorthWestern's support of the ENERGY STAR® Homes Northwest building standards through this program, an average of 85% of the lamps are ENERGY STAR® high efficiency products.

5. E+ Electric Motor Rewind Rebate: NorthWestern offers incentives for motor rewinding. Currently, only four electric motor service centers in NorthWestern's electric service area perform motor rewinding service. Rather than operating a separate and distinct electric motor efficiency program with attendant program-specific administrative costs, NorthWestern folded qualified motor rewinds into the Commercial Electric Rebate Program for Existing Facilities and the Commercial Electric Rebate Program for New Construction. Program marketing during 2012-2013 included sponsorship of motor management

seminars (see Efficient Motor Management details in the training section below).

Additional information about all of NorthWestern's DSM programs is available at NorthWestern's website at http://www.northwesternenergy.com/eplus.

Q. Does NorthWestern conduct other supporting activities to build customer interest and participation in its DSM programs?

A. Yes. NorthWestern DSM staff and contractors sponsor many training seminars during the year to increase awareness of energy conservation and energy efficiency opportunities in buildings and facilities. The objectives are to educate and inform building operators, designers, builders, and trade allies about using electric equipment efficiently and to promote the E+ programs, services, information resources, and incentives. A blend of USB and DSM funds covers the cost of these activities. The following is a list of DSM and USB program-related training seminars that NorthWestern sponsored near the end of the 2011-2012 tracker time period and during 2012-2013:

1. Preferred Contractor Training – Each year NorthWestern provides training to various contractors that install energy saving measures in

the residential homes of consumers who participate in its DSM programs. Training locations for 2013 are currently being scheduled.

2. Efficient Motor Management – Training was targeted at motor users, electricians, motor service shops; Continuing Education Units ("CEUs") were offered; 90 total participants.

   a. Billings – May 13, 2012 (16 attendees).
   b. Bozeman - May 14, 2012 (8 attendees).
   c. Great Falls - May 15, 2012 (14 attendees).
   d. Helena - May 16, 2012 (26 attendees).
   e. Missoula - May 17, 2012 (16 attendees).

3. Building Operator Certification – This is targeted at public schools, non-profit hospitals, state and local government; funding provided for tuition and travel. Level I training was held in the 2012-2013 tracker period. Due to curriculum changes no additional sessions were held. The new curriculum is expected to be adopted and offered during the second half of 2013. Level I training & certification was completed November 5-9, 2012 in Butte with 15 attendees.

4. Opportunities in New Home Construction Workshops – Recent changes in the Montana energy code, along with significant changes to the Northwest Energy Star Homes ("NWESH") Program, provided an important opportunity to solidify home designer and builder energy-efficiency practices. The recently completed Montana Energy Code

Compliance Study underscores the importance of these topics. The results of the study were reviewed as an introduction to the workshops. During the summer of 2012, two two-hour trainings in Missoula, Billings, Great Falls, Helena, and Bozeman were held to discuss the changes. The following topics were presented in each community:

Topic 1: The Importance of Performance Testing: The importance of tightness testing for building envelope and ducts and implications for mechanical ventilation.

Topic 2: Insulation Installations That Work: What building science says about the most effective crawlspace and basement insulation and vapor retarders. Advanced framing and insulation grading also were discussed.

5. Northwest ENERGY STAR® Verifier Training – A Home Energy Rating System week-long course that includes NWESH Program administration, Home Energy Rater System administration, performance testing, and use of home analysis software was held October 8-12, 2012 in Missoula. There were eight participants. This event augmented NWE's effort to promote ENERGY STAR® Homes, and NorthWestern Energy rebates and incentives were discussed in detail. In addition, NorthWestern Energy-funded publications such as

the NWESH Field Guide and Montana Builder Energy Code Checklist were incorporated as a part of the training curriculum.

6. Billings Small Group Builder Training – At NCAT's request, Billings Insulation sponsored a lunch meeting and invited 12 builders to learn about ENERGY STAR® Version 3.

7. Northwest ENERGY STAR® Builder Training – Each of these trainings featured presentations about NorthWestern rebates, incentives, and DSM programs. The material promoting the trainings was approved by NorthWestern Energy staff prior to distribution.

To make training more accessible to more commercial customers, multiple energy management topic webinars sponsored by NEEA are posted on the website and promoted in the electronic newsletter to commercial and industrial customers throughout 2012 and 2013. These webinars are free to customers.

8. Strategic Energy Management – In Missoula on April 25, 2013 NorthWestern co-sponsored training providing the basic tools every company can use to manage energy as a controllable cost. The training promoted a systematic approach to monitor, control and conserve energy thereby reducing operating costs.

9. Adjustable Speed Drive Training – This took place on August 23, 2012 in Billings with 24 attendees.

10. Industrial Customer Cohort – NorthWestern joined with NEEA to pilot test a year-long training and networking process with five industrial customers in non-competing industries to encourage customers to incorporate energy management into their business culture and operating practices. Participating customers commit to attending/hosting sessions, participating in "homework," and reporting to the cohort of actions, including participation in other NWE training and E+ programs. This is the second cohort of its kind in NorthWestern's service territory.

Q. Did NorthWestern make additional efforts during the 2012-2013 tracker period to promote DSM?

A. Yes. To communicate information about DSM and other NorthWestern programs to its customers, NorthWestern sustains a presence in Montana communities through media, events, appearances, meetings, speaking engagements, booth sponsorships, trade fairs and shows, conferences, and other special events. NorthWestern maintains networks of retailers, distributors, and other trade allies and provides a steady stream of information about its DSM programs through print, radio, television, distribution literature, and personal contact. As with the training seminars described above, a mix of USB and DSM funding is used. The following list provides examples of the many activities NorthWestern performed during the past year as well as what it plans for the next year to market its DSM programs:

1. Trade Shows – In fall 2012 and spring 2013, NWE staffed exhibits and educational display booths at seven home improvement trade shows around Montana providing educational materials and distributing four free CFLs per account to NWE's residential electric customers.

2. Game Day Event with NEEA – Promotions included ENERGY STAR® Most Efficient television sets to the winners of a contest sponsored by NEEA.

3. Montana Lodging and Hospitality Association Conference – NorthWestern hosted a display booth at this November 2012 conference.

4. Montana Joint Engineers Conference – November 2012, training and display booth in cooperation with NEEA's BetterBricks.

5. NorthWestern Energy Lighting Trade Ally Network – Focused on commercial lighting and the trade allies supporting this key energy efficiency opportunity; these meetings to be held in 2013 are in the process of being scheduled for Billings, Bozeman, Butte, Missoula, Helena, and Great Falls. An electronic newsletter is sent to participants on a quarterly basis with updates on technologies and case studies of NorthWestern Energy customer projects. NorthWestern includes other resources for lighting professionals and trade allies associated with NorthWestern's E+ programs in the e-newsletter.

6. Montana Building Code Education Conference – April 2013, Bozeman, display booth.

7. Montana Hospital Association Conference – April 2013, display booth.

8. Montana American Institute of Architects Conference – scheduled for the fall of 2013, booth in partnership with BetterBricks.

9. Montana Society of Health Care Engineers/ASHRAE[2] Conference – May 2013, display booth.

10. CFL Instant Savings Coupon Campaigns – In October 2012 for Energy Awareness Month and in April 2013 to observe Earth Day.

11. "Simple Steps" Regional CFL Campaign – Upstream manufacturers' buy-down for specialty CFLs.

12. Home Energy Weatherization Distribution Events – Fall 2012 – 37 events around Montana with a focus on:

a. Air infiltration sealing and CFLs.

b. Direct mail to targeted customers, with web and bill insert promotion.

c. "How-to-install" DVD was distributed with each weatherization kit.

[2] The American Society of Heating, Refrigerating and Air Conditioning Engineers is an international technical society for all individuals and organizations interested in heating, ventilation, air-conditioning, and refrigeration. See www.ashrae.org.

Table 3: 2012 Home Energy Events Schedule and Participants

Date	Location	Participants
12-Sep-12	Fairfield	25
12-Sep-12	Red Lodge	62
12-Sep-12	Vaughn	42
13-Sep-12	Absarokee	46
13-Sep-12	Columbus	35
13-Sep-12	Conrad	39
13-Sep-12	Valier	34
14-Sep-12	Chester	23
14-Sep-12	Chinook	46
14-Sep-12	Harlowton	54
14-Sep-12	Lewistown	82
15-Sep-12	Great Falls	11
15-Sep-12	Havre	78
19-Sep-12	Anaconda	115
20-Sep-12	Big Fork	21
20-Sep-12	Sheridan	42
20-Sep-12	Whitehall	56
21-Sep-12	Columbia Falls	64
21-Sep-12	Dillon	57
21-Sep-12	Twin Bridges	16
21-Sep-12	Whitefish	46
22-Sep-12	Butte	207
22-Sep-12	Kalispell	117
26-Sep-12	Lolo	78
27-Sep-12	Florence	35
27-Sep-12	Manhattan	93
27-Sep-12	Stevensville	103
27-Sep-12	Three Forks	30
28-Sep-12	Belgrade	107
28-Sep-12	Corvallis	56
28-Sep-12	Hamilton	129
28-Sep-12	Livingston	103
29-Sep-12	Bozeman	214
29-Sep-12	Missoula	331
3-Oct-12	Montana City	48
4-Oct-12	East Helena	73
6-Oct-12	Helena	341
	TOTALS	**3059**

13. E+ Audit for the Home – Direct mail in summer and winter 2012 and spring of 2013. Spot placement of television, radio, and newspaper promotion.

14. E+ Tips, CFL, and Commercial Lighting television spots – Spot placement during selected events.

15. Home & Garden Improvement Shows

   a. Fall 2012 – Billings.
   b. Spring 2013 – Missoula (2 shows), Billings, Great Falls, Helena, and Butte.

16. Farmers Markets - CFL distribution – summer of 2012.

17. Parade of Homes Sponsorships (Fall 2012) - Billings, Bozeman, Great Falls, Missoula, Helena, Hamilton.

18. Other Special Events:

   a. Montana Manufacturers Energy Conference – sponsorship, speaker and display booth.
   b. Small Business Administration events in Butte and Helena in the spring of 2013.
   c. Montana Renewable Energy Association conference sponsorship and booth.
   d. Laurel Aviation Youth Event – classroom presentations in May of 2013.

More details about the techniques, mechanisms, locations, forms of media, and calendar schedule are presented in Exhibit__(WMT-4a) which describes the goals, objectives, audiences, strategies, tactics, methods, and tools of the DSM Communications Plan. Exhibit__(WMT-4b) provides a detailed schedule of specific programs and activities that will be implemented during a typical calendar year period. Together, these exhibits present a clear view of the scope and scale of NorthWestern's communications activities and sustained efforts to support its DSM programs, gain customer participation, and acquire cost-effective DSM resources. The DSM Communications Plan serves as a working plan that can and will be changed and adapted as conditions warrant or new knowledge is gained.

Q. Is NorthWestern making other changes or modifications to its electric DSM Programs for the 2013-2014 period?

A. Yes. The DSM Evaluation recently completed by SBW offered recommendations for changes to NorthWestern's electric DSM Programs. As a direct result of these findings and recommendations, NorthWestern has made or is in the process of making the following adjustments to its programs:

- Assume 2.02 burn hours/day instead of 3.7 hours/day to calculate estimated energy savings for residential CFLs.

- Assume 6.14 burn hours/day instead of 3.7 hours/day to calculate estimated energy savings for commercial CFLs.
- Use SBW-derived deemed energy savings for some prescriptive rebate measures and other programs instead of using the corresponding values for deemed measure savings developed in the 2010 electric and 2008 natural gas DSM Potential Assessment Study.
- Eliminate some prescriptive rebate measures that no longer pass the Total Resource Cost test based on SBW-derived deemed measure savings.
- Eliminate DSM funding of customer education/marketing during residential and commercial audits.
- Reduce the number of inspections for some selected prescriptive rebate measures.
- Reduce contractor (KEMA) labor costs expended on some select prescriptive rebate measure qualification verifications.
- Discontinue annual customer education/weatherization kit distribution events in numerous communities around Montana.

Recovery of DSM Program Costs and Lost Revenues

Q. What are the DSM program costs for Tracker Year 2013-2014 and how does NorthWestern propose to recover them?

A. Exhibit__(WMT-2) presents budget figures for individual electric DSM programs that total $9,618,958 (refer to cell O36) for the 2013-2014

Tracker Year. This amount represents estimated DSM program costs and is included as a line item with other supply expenses in the Prefiled Direct Testimony of Frank V. Bennett. The electric supply rates established to recover all supply power expenses include recovery of $9,618,958 for 2013-2014 Tracker Year DSM program costs.

Q. Does NorthWestern propose to continue recovery of Lost Revenues associated with DSM program activity?

A. Yes. DSM Lost Revenues are a function of reduced transmission and distribution ("T&D") throughput caused by NorthWestern's DSM program activity. Additional DSM has been acquired in this tracker period, adding to the accumulated energy savings from NorthWestern's DSM program activities since the last reset of transmission and distribution rates, which became effective on July 8, 2010.[3] This accumulating energy savings further reduces the transmission and distribution throughput volumes compared to the prior tracking period. This, in turn, negatively affects NorthWestern's ability to recover fixed costs associated with the transmission and distribution system through volumetric rates.

Q. Does NorthWestern propose to continue recovery of Lost Revenues associated with CU4?

A. Yes, NorthWestern proposes to recover the Lost Revenues associated with the fixed cost portion of the revenue requirement of CU4. Similar to

[3] Refer to General Rate Case Docket No. D2009.9.129, Interim Order No. 7046g and Final Order No. 7046h.

T&D rates, the CU4 fixed costs will be reset in a future CU4 revenue requirements proceeding, but that did not occur during this tracking period. The Lost Revenues calculations associated with these fixed costs appear as a separate additional worksheet tab (pages 12-16 of Exhibit__(WMT-3)) in the Electric DSM Lost Revenues spreadsheet described below.

Q. Does NorthWestern propose to continue recovery of Lost Revenues associated with DGGS?

A. Yes, NorthWestern proposes to recover the Lost Revenues associated with the fixed cost portion of the revenue requirement of DGGS that was placed into commercial operation on January 1, 2011. Similar to T&D rates, the DGGS fixed costs will be reset in a future revenue requirements proceeding. The Lost Revenue calculations associated with these fixed costs appear as a separate additional worksheet tab (pages 17-19 of Exhibit__(WMT-3)) in the Electric DSM Lost Revenues spreadsheet described below.

Q. Does NorthWestern propose recovery of Lost Revenues associated with Spion?

A. Yes, NorthWestern proposes to recover the Lost Revenues associated with the fixed cost portion of the revenue requirement of Spion that was placed into commercial operation on December 1, 2012. The Lost Revenue calculations associated with these fixed costs appear as a separate additional worksheet tab (pages 20-21 of Exhibit__(WMT-3)) in the Electric DSM Lost Revenues spreadsheet described below.

Q. Please describe the individual components of the Electric DSM Lost Revenues spreadsheet and the various data inputs used in its calculations.

A. The Electric DSM Lost Revenues calculation is performed using a spreadsheet workbook model, included herein as Exhibit__(WMT-3), that is comprised of nine separate worksheet tabs (names of tabs in bold below) that compile program budgets, costs, energy savings estimates, rates, revenues, and adjustment factors into a series of calculations that result in DSM Lost Revenues. Additional notes and explanations are included on the individual spreadsheet tabs, identified as separate pages of Exhibit__(WMT-3).

1. DSM LR Summary (Exhibit__(WMT-3), page 1) presents the results of the DSM Lost Revenues computations for tracker periods starting with the 2009-2010 tracker period, including the calculations for Lost Revenues related to CU4, DGGS, and Spion that are performed on the subsequent tabs.

2. Rates (Exhibit__(WMT-3), page 2) details rates in effect for residential and GS-1 customers by line item. The Electric DSM Lost Revenue calculations use transmission and distribution rates from this worksheet tab as inputs to Tab 7 Calc Lost Revenues. These rates are updated each time the Electric DSM Lost Revenues exhibit is prepared for the Annual Electric Supply Tracker filing.

3. Res and CI Energy Savings (Exhibit__(WMT-3), page 3) uses the annual DSM targets and disaggregates them into annual residential and commercial/industrial ("C&I") energy savings targets. These factors are updated each year as NorthWestern gains experience operating DSM programs, collects program participation data, and observes the proportion of energy savings contributed by each customer segment toward annual DSM targets.

4. C&I Demand Sav (Exhibit__(WMT-3), page 4) uses C&I energy savings developed in Tab 3 to determine total C&I annual demand reduction in kilowatt-months ("kw-mths"). The inputs on this tab include the average monthly load factor and a coincidence factor. The monthly load factor is derived from NorthWestern load research data and the coincidence factor is estimated at this time.

5. Savings by Cust Class (Exhibit__(WMT-3), page 5) develops program reported billing savings based on annual energy savings in kWh for the residential class and annual energy savings and demand savings in kw-mths for the C&I class. Demand savings is further disaggregated between GS-1 secondary non-demand and GS-1 primary non-demand. Inputs on this tab are the percentage savings by service level for commercial and industrial Supply customers. The percentages are based on actual program experience. The calculations on this tab are driven by results from the calculations on Tabs 3 and 4.

6. Adjustment Factors (Exhibit__(WMT-3), page 6) presents factors to be applied to residential and C&I program reported billing savings for purposes of calculating Lost Revenues. These factors recognize that actual savings obtained typically differ and are generally less than program savings based solely on engineering calculations. These factors are taken from the findings and conclusions of the 2012 SBW DSM Evaluation.

7. Calc Lost Revenues (Exhibit__(WMT-3), pages 7-11) calculates Lost Revenues based on input from tabs 2, 5 and 6. Results from this tab are used as inputs to Tab 1.

8. CU-4 Related LRs (Exhibit__(WMT-3), pages 12-16) calculates Lost Revenues that are specific to the portion of the energy supply rate associated with recovery of the fixed cost revenue requirement for NorthWestern's share of CU4 that serves Montana jurisdictional loads. The same lost revenue calculation methodology used in tabs 2 through 7 is applied, and the time frame for DSM energy savings relevant to the calculation reflects the fact that the CU4 rate became effective on January 1, 2009.

9. DGGS Related LRs (Exhibit__(WMT-3), pages 17-19) calculates Lost Revenues that are specific to the portion of the energy supply rate associated with recovery of the fixed cost revenue requirement for DGGS service to Montana jurisdictional loads. The same lost revenue calculation methodology used in tabs 2 through 7 is applied, and the time frame for DSM energy savings relevant to the calculation reflects the fact that DGGS was placed in commercial service on January 1, 2011.

10. Spion Kop Related LRs (Exhibit__(WMT-3), pages 20-21) calculates Lost Revenues that are specific to the portion of the energy supply rate associated with recovery of the fixed cost revenue requirement for Spion service to Montana jurisdictional loads. The same lost revenue calculation methodology used in tabs 2 through 7 is applied, and the time frame for DSM energy savings relevant to the calculation reflects the fact that Spion was placed in commercial service on December 1, 2012.

Q. How are the Lost Revenues trued up and what amounts are you proposing to include as an adjustment to supply rates to recover Lost Revenues?

A. Exhibit__(WMT-3) provides updated calculations of electric Lost Revenues. A true-up to the Lost Revenue calculations is required each time a new DSM tracker is prepared because NorthWestern prepares and files a new annual tracker before the current tracking period ends. This schedule requires computation of DSM Lost Revenues based on 9 months of actual reported energy savings (July through March) and 3 months of estimated energy savings (April through June) for the concluding (or current) tracking period. Normally, the savings is updated to reflect 12 months of actual information in response to discovery or in rebuttal testimony in the current docket.

Also, the final results of the DSM Evaluation were used to recalculate the Lost Revenues for each of the relevant past trackers. This reconciliation of past Lost Revenues was provided in the Prefiled Supplemental Testimony, and updated in the Prefiled Rebuttal Testimony, of William M. Thomas in Docket No. D2012.5.49. That reconciliation of past Lost Revenues serves as the point of beginning for calculations of DSM Lost Revenues for the 2012-2013 tracker period.

Q. What amounts are you proposing to include as an adjustment to supply rates to recover Lost Revenues?

A. NorthWestern proposes that electric supply rates include recovery of the amount of $8,637,107 for total Electric DSM Lost Revenues for the 2012-2013 Tracker Year (refer to cell F13 on page 1 of Exhibit__(WMT-3)).

The forward-looking total Electric DSM Lost Revenues for the 2013-2014 Tracker Year are $10,971,971 (refer to cell F15 on page 1 of Exhibit__(WMT-3)).

Q. Does this complete your testimony?

A. Yes, it does.

Table A: Reported Electricity Savings from 2012-13 USB and DSM Program Activity

Programs	Annualized Energy Savings[1]			
	USB		DSM	
	kWh	aMW	kWh	aMW
General Default Supply DSM Expenses	-	-	-	-
E+ Energy Audit for the Home or Business (Elec)	1,134,139	0.13	-	-
E+ Business Partners Program	-	-	7,527,333	0.86
E+ Irrigation	779,882	0.09	-	-
E+ Commercial Lighting Rebate Program	99,568	0.01	15,327,781	1.75
E+ Residential Lighting Program	-	-	22,033,140	2.52
Builder Operator Certification	216,172	0.02	-	-
Northwest Energy Efficiency Alliance (NEEA)	-	-	8,060,789	0.92
Energy Star 80 Plus Program	-	-	1,945,962	0.22
E+ Free Weatherization Program & Fuel Switch	293,873	0.03	-	-
E+ Renewable Energy Program	753,378	0.09	-	-
Energy Star New Homes Program	18,122	0.00	-	-
E+ Residential NC Electric Rebate Program	-	-	4,528	0.00
E+ Residential EX Electric Rebate Program	-	-	26,936	0.00
E+ Commercial NC Electric Rebate Program	-	-	251,341	0.03
E+ Commercial EX Electric Rebate Program	-	-	3,553,670	0.41
E+ Residential NC Gas Rebate Program	-	-	-	-
E+ Residential EX Gas Rebate Program	-	-	-	-
E+ Commercial NC Gas Rebate Program	-	-	-	-
E+ Commercial EX Gas Rebate Program	-	-	-	-
Total	3,295,133	0.38	58,731,480	6.70

Note 1: Annualized energy savings are based on 9 months of actual savings (July - March) and 3 months estimated.

USB + DSM savings acquired in 2012-13 Tracker Period (aMW): 7.08

Table B: Residential and Commercial Electric Savings for Calculation of Lost T& D Revenues

Programs	USB + DSM Programs						
	% Residential	kWh	% Commercial	kWh	Total kWh	Residential % of Total[2]	Commercial % of Total[2]
General Default Supply DSM Expenses	0%	-	0%	-	-		
E+ Energy Audit for the Home or Business (Elec)	80%	907,311	20%	226,828	1,134,139		
E+ Business Partners Program	0%	-	100%	7,527,333	7,527,333		
E+ Irrigation	0%	-	100%	779,882	779,882		
E+ Commercial Lighting Rebate Program	0%	-	100%	15,427,348	15,427,348		
E+ Residential Lighting Program	100%	22,033,140	0%	-	22,033,140		
Builder Operator Certification	0%	-	100%	216,172	216,172		
Northwest Energy Efficiency Alliance (NEEA)	97%	7,818,966	3%	241,824	8,060,789		
Energy Star 80 Plus Program	0%	-	100%	1,945,962	1,945,962		
E+ Free Weatherization Program & Fuel Switch	100%	293,873	0%	-	293,873		
E+ Renewable Energy Program	70%	527,364	30%	226,013	753,378		
Energy Star New Homes Program	100%	18,122	0%	-	18,122		
E+ Residential NC Electric Rebate Program	100%	4,528	0%	-	4,528		
E+ Residential EX Electric Rebate Program	100%	26,936	0%	-	26,936		
E+ Commercal NC Electric Rebate Program	0%	-	100%	251,341	251,341		
E+ Commercial EX Electric Rebate Program	0%	-	100%	3,553,670	3,553,670		
E+ Residential NC Gas Rebate Program	100%	-	0%	-	-		
E+ Residential EX Gas Rebate Program	100%	-	0%	-	-		
E+ Commercial NC Gas Rebate Program	0%	-	100%	-	-		
E+ Commercial EX Gas Rebate Program	0%	-	100%	-	-		
		31,630,240		30,396,373	62,026,613	50.99%	49.01%

Note 2: Overall Residential and Commercial percentages are used in calculation of Lost Revenues in Exhibit__(WMT-3).

Exhibit__(WMT-2)

Docket D2013.5.33

Electric Supply DSM Program Spending and Budget

		2012-2013 Tracker Year												
		Actual Recorded Spending (July through April) - from SAP Records										Estimated		
Electric DSM Program Spending	**Order**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Total**
General Expenses Related to All DSM Programs	17054	$ 127	$ 425,936	$ 217,276	$ 9,959	$ 671	$ 4,479	$ 145,160	$ 1,885	$ 31,659	$ 436	$ 93,403	$ 225,179	$ 1,156,168
E+ Residential Lighting Program	17055	$ 23,736	$ 365,697	$ 97,630	$ 49,628	$ 365,235	$ 69,493	$ -	$ 254,955	$ 89,805	$ 144,589	$ 180,576	$ 260,471	$ 1,901,815
E+ Residential Electric Savings Program	17056	$ 212	$ 21,574	$ 20,856	$ -	$ 20,615	$ 15,928	$ -	$ -	$ 123	$ 22,396	$ 24,200	$ 24,200	$ 150,104
E+ Residential New Construction Program	17059	$ 959	$ 5,020	$ 2,920	$ -	$ 2,172	$ 1,849	$ -	$ -	$ -	$ 3,179	$ -	$ -	$ 16,098
E+ Commercial Lighting Program	17060	$ -	$ 807,703	$ 243,706	$ 72,891	$ 249,867	$ 118,533	$ 105,675	$ 272,020	$ 332,717	$ 469,063	$ 690,389	$ 176,155	$ 3,538,719
E+ Commercial New Construction Program	17062	$ 200	$ 2,318	$ 12,292	$ -	$ 31,198	$ 4,830	$ -	$ 7	$ -	$ 34,393	$ -	$ -	$ 85,237
E+ Business Partners Program	17063	$ 66,377	$ 640,077	$ 46,964	$ 321,973	$ 454,835	$ 298,823	$ 56,976	$ 35,000	$ 51,278	$ 219,071	$ 72,850	$ 342,515	$ 2,606,739
E+ Commercial Electric Rebate Program	17064	$ 1,357	$ 106,975	$ 284,299	$ 31,125	$ 63,698	$ 121,518	$ 40,267	$ 2,665	$ 42,428	$ 285,944	$ 40,700	$ 40,700	$ 1,061,676
Market Transformation (NEEA)	17067	$ 362,165	$ 4,193	$ 36	$ 364,225	$ 164	$ 18	$ 362,861	$ 240	$ 35	$ 362,208	$ -	$ -	$ 1,456,146
Monthly Total Spending		$ 455,133	$ 2,379,492	$ 925,980	$ 849,801	$ 1,188,455	$ 635,469	$ 710,938	$ 566,772	$ 548,044	$ 1,541,279	$ 1,102,118	$ 1,069,220	$ 11,972,701
Cumulative Total Spending (for 2012-13 Tracker Year 10+2)		$ 455,133	$ 2,834,625	$ 3,760,604	$ 4,610,405	$ 5,798,860	$ 6,434,329	$ 7,145,267	$ 7,712,039	$ 8,260,084	$ 9,801,363	$ 10,903,481	$ 11,972,701	$ 11,972,701

Note: Actual Program Expenses through April 30, 2013 as of May 09, 2013

		2013-2014 Tracker Year												
		Estimated												
Electric DSM Program Spending	**Order**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Total**
General Expenses Related to All DSM Programs	17054	$ 12,709	$ 11,601	$ 29,981	$ 12,659	$ 14,829	$ 10,109	$ 82,891	$ 8,180	$ 145,831	$ 11,027	$ 5,130	$ 143,495	$ 488,441
E+ Residential Lighting Program	17055	$ 26,115	$ 185,600	$ 125,216	$ 3,642	$ 337,405	$ 291,731	$ -	$ 93,354	$ 75,591	$ 251,462	$ 180,576	$ 260,471	$ 1,831,163
E+ Residential Electric Savings Program	17056	$ 14,543	$ 20,986	$ 12,736	$ 13,948	$ 10,979	$ 8,670	$ 15,128	$ 13,628	$ 17,934	$ 24,200	$ 24,200	$ 24,200	$ 201,153
E+ Residential New Construction Program	17059	$ 5,370	$ 12,955	$ 1,072	$ 2,740	$ 3,351	$ 2,052	$ 1,097	$ 2,258	$ 1,591	$ 8,659	$ -	$ -	$ 41,144
E+ Commercial Lighting Program	17060	$ 121,848	$ 321,024	$ 153,757	$ 65,895	$ 173,122	$ 317,356	$ 339	$ 278,674	$ 165,082	$ 380,685	$ 690,389	$ 176,155	$ 2,844,327
E+ Commercial New Construction Program	17062	$ 854	$ 3,049	$ 12,007	$ 1,839	$ 3,393	$ 2,032	$ 4,264	$ 4,117	$ 23,101	$ 7,774	$ -	$ -	$ 62,430
E+ Business Partners Program	17063	$ 420,796	$ 242,981	$ 157,968	$ 170,484	$ 105,003	$ 74,671	$ 4,139	$ 62,192	$ 16,118	$ 344,872	$ 80,135	$ 376,767	$ 2,056,125
E+ Commercial Electric Rebate Program	17064	$ 22,814	$ 3,722	$ 83,994	$ 32,500	$ 114,271	$ 110,204	$ 8,846	$ 96,937	$ 80,129	$ 24,200	$ 40,700	$ 40,700	$ 659,016
Market Transformation (NEEA)	17067	$ 358,790	$ -	$ -	$ 358,790	$ -	$ -	$ 358,790	$ -	$ -	$ 358,790	$ -	$ -	$ 1,435,160
Monthly Total Spending		$ 983,840	$ 801,918	$ 576,730	$ 662,495	$ 762,352	$ 816,824	$ 475,494	$ 559,340	$ 525,377	$ 1,411,669	$ 1,021,131	$ 1,021,787	$ 9,618,958
Cumulative Total Spending (for 2013-14 Tracker Year)		$ 983,840	$ 1,785,758	$ 2,362,488	$ 3,024,984	$ 3,787,336	$ 4,604,160	$ 5,079,655	$ 5,638,995	$ 6,164,372	$ 7,576,041	$ 8,597,171	$ 9,618,958	$ 9,618,958

Electric DSM Lost Revenues

Row	Time Period[1]	Montana T&D	Colstrip Unit #4	Dave Gates Mill Creek Station[2]	Spion Kop[3]	Total DSM Lost Revenue[4]
3	**Tracker 2009-10**	$ 3,175,025	$ 752,795			$ 3,927,820
4						
5	**Tracker 2010-11:**					
6	**July-December 2010**	$ 506,627	$ 779,083	$ -		$ 1,285,711
7	**January-June 2011**	$ 1,036,879	$ 779,083	$ 69,327		$ 1,885,289
8		$ 1,543,506	$ 1,558,167	$ 69,327		$ 3,170,999
10						
11	**Tracker 2011-12**	$ 2,962,327	$ 2,190,459	$ 278,111		$ 5,430,897
12						
13	**Tracker 2012-13**	$ 5,007,379	$ 3,003,976	$ 608,961	$ 16,791	$ 8,637,107
14						
15	**Tracker 2013-14**	$ 6,395,592	$ 3,653,224	$ 853,436	$ 69,719	$ 10,971,971

Notes:

The starting point for this Exhibit__(WMT-3) for the 2013-2014 electric tracker (D2013.5.33) was the spreadsheet workbook *5.2UPDATEDRecon-SBW-Exhibit__(WMT-3) Electric DSM Lost Revenues 12 mth actual 2010-13 with backup.xlsx* that was developed for William M. Thomas Rebuttal testimony in D2012.5.49. Lost Revenues for 2009-10 were copied from that Exhibit__(WMT-5.2) into line 3 in the table immediately above. Lost Revenues for all other periods summarized above are calculated in this workbook.

1. Electric DSM Lost Revenues were reset Jan. 1, 2008 due to newly established T&D rates
Refer to Electric Default Supply Service D2007.7.80, Tariff 144-E and
General Rate Case D2007.7.82 Interim Order No. 6852b, Tariff 145-E

Tracker Period 2011-2012 based on 12 month actual reported energy savings (excluding NorthWestern Facilities DSM)
Tracker Period 2012-2013 based on 9+3 energy savings (excluding NorthWestern Facilities DSM)

Electric DSM Lost Revenues were reset again on Jan. 1, 2011 due to newly established T&D rates
Refer to Docket D2009.9.129, Final Order No. 7046h

2. DGGS began commercial service on January 1, 2011

3. Spion Kop began commercial service on December 1, 2012

Electric DSM Lost Revenues

2010-11 Tracking Period

Period July – December 2010

Reference: Compliance Filing on December 21, 2010 Docket D2009.9.129, Final Order 7046b; Work-Papers Section "Electric Utility Approved Revenue Requirement ACOS and Derivation of Rates" Page 3 of 4 Column D.

Residential:		
Transmission Energy	$0.008918	per kwh
Distribution Energy	$0.027761	per kwh
GS 1 Secondary, non-demand		
Transmission Energy	$0.007765	per kwh
Distribution Energy	$0.035955	per kwh
GS 1 Secondary, demand		
Transmission Demand	$2.966798	per kw
Distribution Energy	$0.004797	per kwh
Distribution Demand	$6.047753	per kw
General Service - 1 Primary, Non Demand:		
Transmission Energy	$0.008122	per kwh
Distribution Energy	$0.018623	per kwh
General Service - 1 Primary, Demand:		
Transmission Demand	$3.605969	per kw
Distribution Energy	$0.006936	per kwh
Distribution Demand	$3.959563	per kw

Period January – June 2011

Reference: 2011 Annual Tax Tracker Filing Application December 23, 2010, Docket D2010.12.116, Final Order 7131a; Appendix A Pages 1 – 4, Column (B) + (E), excluding rebate in Column (C).

Residential:		
Transmission Energy	$0.009051	per kwh
Distribution Energy	$0.028176	per kwh
GS 1 Secondary, non-demand		
Transmission Energy	$0.007881	per kwh
Distribution Energy	$0.036493	per kwh
GS 1 Secondary, demand		
Transmission Demand	$3.011163	per kw
Distribution Energy	$0.004869	per kwh
Distribution Demand	$6.138191	per kw
General Service - 1 Primary, Non Demand:		
Transmission Energy	$0.008244	per kwh
Distribution Energy	$0.018902	per kwh
General Service - 1 Primary, Demand:		
Transmission Demand	$3.659893	per kw
Distribution Energy	$0.007040	per kwh
Distribution Demand	$4.018774	per kw

2011-12 Tracking Period

Period July 2011-December 2011

Residential:		
Transmission Energy	0.009076	per kwh
Distribution Energy	0.028259	per kwh
GS 1 Secondary, non-demand		
Transmission Energy	0.007904	per kwh
Distribution Energy	0.036600	per kwh
GS 1 Secondary, demand		
Transmission Demand	3.019986	per kw
Distribution Energy	0.004883	per kwh
Distribution Demand	6.156176	per kw
General Service - 1 Primary, Non Demand:		
Transmission Energy	0.008268	per kwh
Distribution Energy	0.018957	per kwh
General Service - 1 Primary, Demand:		
Transmission Demand	3.670616	per kw
Distribution Energy	0.007061	per kwh
Distribution Demand	4.030549	per kw

Period January-June 2012

Residential:		
Transmission Energy	0.008866	per kwh
Distribution Energy	0.027599	per kwh
GS 1 Secondary, non-demand		
Transmission Energy	0.007719	per kwh
Distribution Energy	0.035745	per kwh
GS 1 Secondary, demand		
Transmission Demand	2.949439	per kw
Distribution Energy	0.004769	per kwh
Distribution Demand	6.012368	per kw
General Service - 1 Primary, Non Demand:		
Transmission Energy	0.008075	per kwh
Distribution Energy	0.018514	per kwh
General Service - 1 Primary, Demand:		
Transmission Demand	3.584870	per kw
Distribution Energy	0.006896	per kwh
Distribution Demand	3.936395	per kw

2012-13 and 2013-14 Tracking Periods

July 1, 2012 - December 31, 2012 Period

Period July 2012-June 2013

Reference: 2012 Annual Tax Tracker Filing Application December 8, 2011, Docket D2012.12.97., Final Order 7191a; Appendix A Pages 1-4

Residential:		
Transmission Energy	0.008866	per kwh
Distribution Energy	0.027599	per kwh
GS 1 Secondary, non-demand		
Transmission Energy	0.007719	per kwh
Distribution Energy	0.035745	per kwh
GS 1 Secondary, demand		
Transmission Demand	2.949439	per kw
Distribution Energy	0.004769	per kwh
Distribution Demand	6.012368	per kw
General Service - 1 Primary, Non Demand:		
Transmission Energy	0.008075	per kwh
Distribution Energy	0.018514	per kwh
General Service - 1 Primary, Demand:		
Transmission Demand	3.584870	per kw
Distribution Energy	0.006896	per kwh
Distribution Demand	3.936395	per kw

January 1, 2013 Forward

Period January 2013 forward (until next change)

Reference: 2013 Annual Tax Tracker; December 11, 2012; Docket No. D2012.12.124; Apprendix A (by operation of law)

Residential:		
Transmission Energy	0.009188	per kwh
Distribution Energy	0.028601	per kwh
GS 1 Secondary, non-demand		
Transmission Energy	0.007999	per kwh
Distribution Energy	0.037043	per kwh
GS 1 Secondary, demand		
Transmission Demand	3.056510	per kw
Distribution Energy	0.004942	per kwh
Distribution Demand	6.230629	per kw
General Service - 1 Primary, Non Demand:		
Transmission Energy	0.008368	per kwh
Distribution Energy	0.019186	per kwh
General Service - 1 Primary, Demand:		
Transmission Demand	3.715008	per kw
Distribution Energy	0.007146	per kwh
Distribution Demand	4.079294	per kw

Averaged Rates used for 2012-13 Tracking Period[1]

Residential:		
Transmission Energy	0.009027	per kwh
Distribution Energy	0.028100	per kwh
GS 1 Secondary, non-demand		
Transmission Energy	0.007859	per kwh
Distribution Energy	0.036394	per kwh
GS 1 Secondary, demand		
Transmission Demand	3.002975	per kw
Distribution Energy	0.004856	per kwh
Distribution Demand	6.121499	per kw
General Service - 1 Primary, Non Demand:		
Transmission Energy	0.008222	per kwh
Distribution Energy	0.018850	per kwh
General Service - 1 Primary, Demand:		
Transmission Demand	3.649939	per kw
Distribution Energy	0.007021	per kwh
Distribution Demand	4.007845	per kw

Notes:

1. Rates were changed as a result of the Tax Tracker. The effective date of the revised rates was January 1, 2013. This date falls at the midpoint of the 2012-2013 tracker period, so Averaged rates for the full tracker period were calculated and used in Lost Revenue calculations for 2012-2013.

Electric DSM Lost Revenues

Annual Energy Savings:

1) DSM Targets and Results:

	Tracker 2010-11[1]				Tracker 2011-2012		Tracker 2012-2013	
	Period July – December 2010		Period January – June 2011		Period July 2011 – June 2012		Period July 2012 – June 2013	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Annual (Avg. MW)	3.00	**3.38**	3.00	**3.44**	6.00	**9.31**	6.00	**7.08**
Cumulative (Avg. MW)	3.00	3.38	6.38	6.82	12.82	16.13	22.13	23.21

1. Different T&D rates were in effect for each 6-month period, so Total Reported DSM Savings (8.56 aMW) was divided between the two periods. New rates went into effect on July 8, 2010, which is one week later than the beginning of the 2010-11 Tracker Period, so Reported Energy Savings has been "de-rated" by 7 days for the July-December 2010 period.

2) Disaggregate Targets into Residential & Commercial/Industrial[2]

	Period July – December 2010		Period January – June 2011		Period July 2011 – June 2012		Period July 2012 – June 2013	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported
% Residential	67.4%	75.3%	67.4%	75.3%	67.4%	64.9%	69.7%	50.99%
% Commercial & Industrial	32.6%	24.7%	32.6%	24.7%	32.6%	35.1%	30.3%	49.01%
Incremental Res. (Avg. MW)	2.02	2.54	2.02	2.59	4.04	6.04	4.18	3.61
Cumulative Res. (Avg. MW)	2.02	2.54	4.04	5.13	9.18	11.17	15.35	14.78
Incremental C/I (Avg. MW)	0.98	0.83	0.98	0.85	1.96	3.27	1.82	3.47
Cumulative C/I (Avg. MW)	0.98	0.83	1.96	1.68	3.64	4.95	6.77	8.42
check fig:	3.00	3.38	3.00	3.44	6.00	9.31	6.00	7.08

2. Residential/commercial split based on DSM Program results

3) Cumulative Annual Energy Savings[3]

	Period July – December 2010		Period January – June 2011		Period July 2011 – June 2012		Period July 2012 – June 2013	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Residential (MWH)	8,853	11,133	17,707	22,484	62,674	71,415	116,185	113,679
C/I (MWH)	4,287	3,650	8,573	7,371	23,316	29,071	51,357	58,597
Total Savings (MWH)	13,140	14,783	26,280	29,855	85,990	100,486	167,542	172,276
Total Savings (Avg. MW)	1.50	1.69	3.00	3.41	9.82	11.47	19.13	19.67

3. "Half-year convention":
Savings resulting from the "Increment" in any year is reduced by 50% in that year as associated projects are completed and start generating savings at different times throughout the first year. This assumption contemplates that associated projects start generating savings half way through the year on average. In the second year and beyond, projects completed in the first year generate savings for the entire year so the "Increment" is credited at 100% for the second year and each successive year.

Electric DSM Lost Revenues

Commercial/Industrial Reduction in Peak Demand:

1) Commercial/Industrial Average Monthly Load Factor: 66%

2) Calculate Coincident Monthly Demand Reduction:

	Tracker 2010-11				Tracker 2011-2012		Tracker 2012-2013		Tracker 2013-2014	
	Period July – December 2010		Period January – June 2011		Period July 2011 – June 2012		Period July 2012 – June 2013		Period July 2013 – June 2014	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
C/I Energy Savings (MWH)	4,287	3,650	8,573	7,371	23,316	29,071	51,357	58,597	81,753	81,753
C/I Energy Savings (Avg. MW)	0.5	0.4	1.0	0.8	2.7	3.3	5.9	6.7	9.3	9.3
C/I Avg. Monthly Demand Reduction (KW/Mth)*	741	631	1,483	1,275	4,033	5,028	8,883	10,135	14,140	14,140
C/I Annual Demand Reduction (KW-Mths)	8,897	7,576	17,794	15,300	48,394	60,338	106,594	121,621	169,683	169,683

3) Coincidence Factor: 100% *

* Coincidence Factor is estimated. 100% load factor assumes that, from a billing perspective, the impacts of class coincidence are offset by the potential of the impacts of specific technologies/projects to be non-coincident with the peak loads of individual customers.

	Tracker 2010-11				Tracker 2011-2012		Tracker 2012-2013		Tracker 2013-2014	
	Period July – December 2010		Period January – June 2011		Period July 2011 – June 2012		Period July 2012 – June 2013		Period July 2013 – June 2014	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
4) C/I Annual Demand Reduction (KW-Mths)*	8,897	7,576	17,794	15,300	48,394	60,338	106,594	121,621	169,683	169,683

* Represents total C/I Demand reduction. Tariffs for GS-1 Primary and Secondary Non-demand customers do not include a demand charge. Demand reductions associated with such customers do not result in lost revenues.

Electric DSM Lost Revenues

Row	A / B	D	E	F	G	H	I	J	K	L	M
4	Estimate Energy and Demand "Bill" Savings for Residential and C/I										
6		Tracker 2010-11				Tracker 2011-12		Tracker 2012-13		Tracker 2013-14	
7		Period July – December 2010		Period January – June 2011		Period July 2011 – June 2012		Period July 2012 – June 2013		Period July 2013 – June 2014	
8		Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
9	**1) Residential Savings (KWH)**	8,853,306	11,132,951	17,706,613	22,483,586	62,673,785	71,415,343	116,185,333	113,678,633	147,815,573	147,815,573
10	**2) C/I Savings**										
11	Energy (KWH)	4,286,694	3,650,046	8,573,387	7,371,462	23,316,312	29,070,933	51,357,121	58,597,127	81,753,494	81,753,494
12	Demand (KW-Mths)	8,897	7,576	17,794	15,300	48,394	60,338	106,594	121,621	169,683	169,683
13	**3) Disaggregate C&I Savings by service level (tariff)**										
15	C&I Savings is broken out as:*										
16	GS-1 Secondary, non demand	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
17	GS-1 Secondary, demand	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
18	GS-1 Primary, non demand	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
19	GS-1 Primary, demand	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
20	Total C&I	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
23	**4) C&I Reported Programmatic "Bill" Savings Based on Breakout in 3) Above:**										
25		Tracker 2010-11									
26		Period July – December 2010		Period January – June 2011		Period July 2011 – June 2012		Period July 2012 – June 2013		Period July 2013 – June 2014	
27	**Energy (KWh)**	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
29	GS-1 Secondary, non demand	42,867	36,500	85,734	73,715	233,163	290,709	513,571	585,971	817,535	817,535
30	GS-1 Secondary, demand	4,200,960	3,577,045	8,401,919	7,224,033	22,849,985	28,489,514	50,329,979	57,425,185	80,118,424	80,118,424
31	GS-1 Primary, non demand	-	-	-	-	-	-	-	-	-	-
32	GS-1 Primary, demand	42,867	36,500	85,734	73,715	233,163	290,709	513,571	585,971	817,535	817,535
33	Check Total	4,286,694	3,650,046	8,573,387	7,371,462	23,316,312	29,070,933	51,357,121	58,597,127	81,753,494	81,753,494
35	**Demand (KW-mth)**										
36	GS-1 Secondary, demand	8,719	7,424	17,439	14,994	47,426	59,131	104,462	119,189	166,290	166,290
37	GS-1 Primary, demand	89	76	178	153	484	603	1,066	1,216	1,697	1,697
38	Total*	8,808	7,500	17,617	15,147	47,910	59,735	105,528	120,405	167,987	167,987

39 Totals are less than totals in row 12 above because non-demand C&I customers are not billed for demand.

Electric DSM Lost Revenues

Adjustment Factors (Net Savings Adjustment Ratios)

For Lost Revenue calculations for the 2010-2011 tracker period, the value of 1.0 is used for this because the actual Net Adjusted Energy Savings from SBW were entered in Tab 3.

Residential	**Net Savings Adjustment Ratio**
Segment	
All	1.0

Commercial/Industrial	**Net Savings Adjustment Ratio**
Segment	
All	1.0

For Lost Revenue calculations for the 2011-2012 tracker period forward, these values are used. SBW, Inc. DSM Evalution Study Savings Realization rate for all Electric DSM programs

Residential	**Net Savings Adjustment Ratio**
Segment	
All	0.89

Commercial/Industrial	**Net Savings Adjustment Ratio**
Segment	
All	0.89

	A	B	C	D	E	F	G	H	I
1									
2	**Electric DSM Lost Revenues - Montana T&D**								
3	**July-December 2010**								
4									
5									
6	**Residential**								
7				**Gross**					**Estimated**
8				**Program**			**Net**		**Lost**
9		**Rate[1]**		**Savings**		**Adjustment**	**Savings**		**Revenue**
10	Bill Line Item	**($ per kwh)**		**(kwh)**		**Factor**	**(kwh)**		**($)**
11	Transmission Energy	0.008918		11,132,951		1.000	11,132,951		99,284
12	Distribution Energy	0.027761		11,132,951		1.000	11,132,951		309,062
13					**Sub Total Residential:**		**11,132,951**		**$ 408,346**
14									
15									
16	**Commercial & Industrial**								
17				**Gross**	**Gross**				**Estimated**
18				**Program**	**Program**		**Net**	**Net**	**Lost**
19		**Rate[1]**	**Rate[1]**	**Savings**	**Savings**	**Adjustment**	**Savings**	**Savings**	**Revenue**
20	Bill Line Item	**($ per kwh)**	**($ per kw-mth)**	**(kwh)**	**(kw-mth)**	**Factor**	**(kwh)**	**(kw-mth)**	**($)**
21	GS-1 Secondary, non demand, TX Energy	0.007765		36,500		1.000	36,500		283
22	GS-1 Secondary, non demand, Dist. Energy	0.035955		36,500		1.000	36,500		1,312
23									
24	GS-1 Secondary, demand, TX Demand		2.966798		8,719	1.000		8,719	25,868
25	GS-1 Secondary, demand, Dist. Energy	0.004797		3,577,045		1.000	3,577,045		17,159
26	GS-1 Secondary, demand, Dist. Demand		6.047753		8,719	1.000		8,719	52,732
27									
28	GS-1 Primary, non demand, TX Energy	0.008122		0		1.000	0		0
29	GS-1 Primary, non demand, Dist. Energy	0.018623		0		1.000	0		0
30									
31	GS-1 Primary, demand, TX Demand		3.605969		89	1.000		89	321
32	GS-1 Primary, demand, Dist. Energy	0.006936		36,500		1.000	36,500		253
33	GS-1 Primary, demand, Dist. Demand		3.959563		89	1.000		89	352
34				**Sub Total Commercial & Industrial:**			**3,650,046**		**$ 98,282**
35									
36			**July-December 2010**	**Estimated Totals:**			**14,782,998**		**$ 506,627**
37	Note 1: using rates in effect at the time (see Rates tab)								
38									

Electric DSM Lost Revenues - Montana T&D

	A	B	C	D	E	F	G	H	I
39	**January-June 2011**								
40									
41									
42	**Residential**								
43				**Gross**					**Estimated**
44				**Program**			**Net**		**Lost**
45		**Rate[1]**		**Savings**		**Adjustment**	**Savings**		**Revenue**
46	Bill Line Item	**($ per kwh)**		**(kwh)**		**Factor**	**(kwh)**		**($)**
47	Transmission Energy	0.009051		22,483,586		1.000	22,483,586		203,499
48	Distribution Energy	0.028176		22,483,586		1.000	22,483,586		633,498
49					**Sub Total Residential:**		**22,483,586**		**$ 836,996**
50									
51									
52	**Commercial & Industrial**			**Reported**	**Reported**				
53				**Gross**	**Gross**				**Estimated**
54				**Program**	**Program**		**Net**	**Net**	**Lost**
55		**Rate[1]**	**Rate[1]**	**Savings**	**Savings**	**Adjustment**	**Savings**	**Savings**	**Revenue**
56	Bill Line Item	**($ per kwh)**	**($ per kw-mth)**	**(kwh)**	**(kw-mth)**	**Factor**	**(kwh)**	**(kw-mth)**	**($)**
57	GS-1 Secondary, non demand, TX Energy	0.007881		73,715		1.000	73,715		581
58	GS-1 Secondary, non demand, Dist. Energy	0.036493		73,715		1.000	73,715		2,690
59									
60	GS-1 Secondary, demand, TX Demand		3.011163		17,439	1.000		17,439	52,510
61	GS-1 Secondary, demand, Dist. Energy	0.004869		7,224,033		1.000	7,224,033		35,174
62	GS-1 Secondary, demand, Dist. Demand		6.138191		17,439	1.000		17,439	107,041
63									
64	GS-1 Primary, non demand, TX Energy	0.008244		0		1.000	0		0
65	GS-1 Primary, non demand, Dist. Energy	0.018902		0		1.000	0		0
66									
67	GS-1 Primary, demand, TX Demand		3.659893		178	1.000		178	651
68	GS-1 Primary, demand, Dist. Energy	0.00704		73,715		1.000	73,715		519
69	GS-1 Primary, demand, Dist. Demand		4.018774		178	1.000		178	715
70				**Sub Total Commercial & Industrial:**			**7,371,462**		**$ 199,882**
71									
72			**January-June 2011**	**Estimated Totals:**			**29,855,049**		**$ 1,036,879**
73	Note 1: using rates in effect at the time (see Rates tab)								
74									

	A	B	C	D	E	F	G	H	I
1									
2	**Electric DSM Lost Revenues - Montana T&D**								
75	**July 2011-June 2012**								
76									
77									
78	**Residential**								
79				**Gross**		**SBW's**			**Estimated**
80		**Average**		**Program**		**NTG**	**Net**		**Lost**
81		**Rate[1]**		**Savings**		**Adjustment**	**Savings**		**Revenue**
82	Bill Line Item	**($ per kwh)**		**(kwh)**		**Factor**	**(kwh)**		**($)**
83	Transmission Energy	0.008972		71,415,343		0.890	63,559,655		570,257
84	Distribution Energy	0.027929		71,415,343		0.890	63,559,655		1,775,158
85					**Sub Total Residential:**		**63,559,655**		**$ 2,345,415**
86									
87									
88	**Commercial & Industrial**			**Reported**	**Reported**				
89				**Gross**	**Gross**	**SBW's**			**Estimated**
90		**Average**	**Average**	**Program**	**Program**	**NTG**	**Net**	**Net**	**Lost**
91		**Rate[1]**	**Rate[1]**	**Savings**	**Savings**	**Adjustment**	**Savings**	**Savings**	**Revenue**
92	Bill Line Item	**($ per kwh)**	**($ per kw-mth)**	**(kwh)**	**(kw-mth)**	**Factor**	**(kwh)**	**(kw-mth)**	**($)**
93	GS-1 Secondary, non demand, TX Energy	0.007812		290,709		0.890	258,731		2,021
94	GS-1 Secondary, non demand, Dist. Energy	0.036173		290,709		0.890	258,731		9,359
95									
96	GS-1 Secondary, demand, TX Demand		2.984713		59,131	0.890		52,627	157,076
97	GS-1 Secondary, demand, Dist. Energy	0.004826		28,489,514		0.890	25,355,668		122,366
98	GS-1 Secondary, demand, Dist. Demand		6.084272		59,131	0.890		52,627	320,197
99									
100	GS-1 Primary, non demand, TX Energy	0.008172		0		0.890	0		0
101	GS-1 Primary, non demand, Dist. Energy	0.018736		0		0.890	0		0
102									
103	GS-1 Primary, demand, TX Demand		3.627743		603	0.890		537	1,948
104	GS-1 Primary, demand, Dist. Energy	0.006979		290,709		0.890	258,731		1,806
105	GS-1 Primary, demand, Dist. Demand		3.983472		603	0.890		537	2,139
106				**Sub Total Commercial & Industrial:**			**25,873,130**		**$ 616,912**
107									
108			**July 2011-June 2012**	**Estimated Totals:**			**89,432,785**		**$ 2,962,327**
109									
110	**Note 1: Two sets of rates were used, each set was effective for 6 months of the 2011-12 tracker period**								
111									

Electric DSM Lost Revenues - Montana T&D

	A	B	C	D	E	F	G	H	I
112	**July 2012-June 2013**								
113									
114									
115	**Residential**			**Reported**					
116				**Gross**		**SBW's**			**Estimated**
117				**Program**		**NTG**	**Net**		**Lost**
118		Rate[1]		**Savings**		**Adjustment**	**Savings**		**Revenue**
119	Bill Line Item	**($ per kwh)**		**(kwh)**		**Factor**	**(kwh)**		**($)**
120	Transmission Energy	0.009027		113,678,633		0.890	101,173,983		913,298
121	Distribution Energy	0.028100		113,678,633		0.890	101,173,983		2,842,989
122					**Sub Total Residential:**		**101,173,983**		**$ 3,756,286**
123									
124									
125	**Commercial & Industrial**			**Reported**	**Reported**				
126				**Gross**	**Gross**	**SBW's**			**Estimated**
127				**Program**	**Program**	**NTG**	**Net**	**Net**	**Lost**
128		Rate[1]	Rate[1]	**Savings**	**Savings**	**Adjustment**	**Savings**	**Savings**	**Revenue**
129	Bill Line Item	**($ per kwh)**	**($ per kw-mth)**	**(kwh)**	**(kw-mth)**	**Factor**	**(kwh)**	**(kw-mth)**	**($)**
130	GS-1 Secondary, non demand, TX Energy	0.007859		585,971		0.890	521,514		4,099
131	GS-1 Secondary, non demand, Dist. Energy	0.036394		585,971		0.890	521,514		18,980
132									
133	GS-1 Secondary, demand, TX Demand		3.002975		119,189	0.890		106,078	318,550
134	GS-1 Secondary, demand, Dist. Energy	0.0048555		57,425,185		0.890	51,108,414		248,157
135	GS-1 Secondary, demand, Dist. Demand		6.121499		119,189	0.890		106,078	649,357
136									
137	GS-1 Primary, non demand, TX Energy	0.008222		0		0.890	0		0
138	GS-1 Primary, non demand, Dist. Energy	0.018850		0		0.890	0		0
139									
140	GS-1 Primary, demand, TX Demand		3.649939		1,216	0.890		1,082	3,951
141	GS-1 Primary, demand, Dist. Energy	0.007021		585,971		0.890	521,514		3,662
142	GS-1 Primary, demand, Dist. Demand		4.007845		1,216	0.890		1,082	4,338
143				**Sub Total Commercial & Industrial:**			**52,151,443**		**$ 1,251,093**
144									
145			**July 2012-June 2013**	**Estimated Totals:**			**153,325,427**		**$ 5,007,379**
146									
147									

Electric DSM Lost Revenues - Montana T&D

	A	B	C	D	E	F	G	H	I
1									
2	Electric DSM Lost Revenues - Montana T&D								
148									
149	**July 2013-June 2014**								
150									
151									
152	**Residential**			TARGET					
153				Gross		SBW's			Estimated
154				Program		NTG	Net		Lost
155		Rate[1]		Savings		Adjustment	Savings		Revenue
156	Bill Line Item	($ per kwh)		(kwh)		Factor	(kwh)		($)
157	Transmission Energy	0.009188		147,815,573		0.890	131,555,860		1,208,735
158	Distribution Energy	0.028601		147,815,573		0.890	131,555,860		3,762,629
159					**Sub Total Residential:**		**131,555,860**		**$ 4,971,364**
160									
161				TARGET					
162	**Commercial & Industrial**			Reported	Reported				
163				Gross	Gross	SBW's			Estimated
164				Program	Program	NTG	Net	Net	Lost
165		Rate[1]	Rate[1]	Savings	Savings	Adjustment	Savings	Savings	Revenue
166	Bill Line Item	($ per kwh)	($ per kw-mth)	(kwh)	(kw-mth)	Factor	(kwh)	(kw-mth)	($)
167	GS-1 Secondary, non demand, TX Energy	0.007999		817,535		0.890	727,606		5,820
168	GS-1 Secondary, non demand, Dist. Energy	0.037043		817,535		0.890	727,606		26,953
169									
170	GS-1 Secondary, demand, TX Demand		3.056510		166,290	0.890		147,998	452,357
171	GS-1 Secondary, demand, Dist. Energy	0.004942		1,697		0.890	1,510		7
172	GS-1 Secondary, demand, Dist. Demand		6.230629		166,290	0.890		147,998	922,120
173									
174	GS-1 Primary, non demand, TX Energy	0.008368		0		0.890	0		0
175	GS-1 Primary, non demand, Dist. Energy	0.019186		0		0.890	0		0
176									
177	GS-1 Primary, demand, TX Demand		3.715008		1,697	0.890		1,510	5,610
178	GS-1 Primary, demand, Dist. Energy	0.007146		817,535		0.890	727,606		5,199
179	GS-1 Primary, demand, Dist. Demand		4.079294		1,697	0.890		1,510	6,160
180				**Sub Total Commercial & Industrial:**			**1,456,722**		**$ 1,424,228**
181									
182			**July 2013-June 2014**	**Estimated Totals:**			**133,012,582**		**$ 6,395,592**
183									
184									

File: Exhibit__(WMT-3) Electric DSM Lost Revenues 2013-2014 values only.xls
Tab: 7.Calc Lost Revenues

Electric DSM Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

DSM Targets and Results:

	January-June 2009		Tracker 2009-10		Tracker 2010-11		Tracker 2011-12		Tracker 2012-13		Tracker 2013-14	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Annual (Avg. MW)	2.50	2.97	5.00	7.56	6.00	6.88	6.00	9.31	6.00	7.08	6.00	6.00
Cumulative (Avg. MW)	2.50	2.97	7.97	10.53	16.53	17.41	23.41	26.72	32.72	33.80	39.80	39.80

Disaggregate Targets into Residential & Commercial/Industrial [1]

	January-June 2009		Tracker 2009-10		Tracker 2010-11		Tracker 2011-12		Tracker 2012-13		Tracker 2013-14	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
% Residential	66.5%	62.1%	66.5%	64.0%	67.4%	75.3%	67.4%	64.9%	69.7%	51.0%	69.7%	69.7%
% Commercial & Industrial	33.5%	37.9%	33.5%	36.0%	32.6%	24.7%	32.6%	35.1%	30.3%	49.0%	30.3%	30.3%
Incremental Res. (Avg. MW)	1.66	1.84	3.33	4.84	4.04	5.18	4.04	6.04	4.18	3.61	4.18	4.18
Cumulative Res. (Avg. MW)	1.66	1.84	4.99	6.68	10.72	11.86	15.91	17.90	22.09	21.51	25.70	25.70
Incremental C/I (Avg. MW)	0.84	1.13	1.68	2.72	1.96	1.70	1.96	3.27	1.82	3.47	1.82	1.82
Cumulative C/I (Avg. MW)	0.84	1.13	2.51	3.85	5.81	5.55	7.50	8.82	10.64	12.29	14.11	14.11
check fig:	2.50	2.97	5.00	7.56	6.00	6.88	6.00	9.31	6.00	7.08	6.00	6.00

1. Residential/commercial split based on DSM Program results

Cumulative Annual Energy Savings[2]	January-June 2009		Tracker 2009-10		Tracker 2010-11		Tracker 2011-12		Tracker 2012-13		Tracker 2013-14	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Residential (MWH)	7,282	8,072	30,708	37,334	76,230	81,225	121,633	130,375	175,144	172,638	206,775	206,775
C/I (MWH)	3,668	4,936	17,208	21,789	42,279	41,149	57,165	62,920	85,206	92,446	115,602	115,602
Total Savings (MWH)	10,950	13,008	47,916	59,123	118,510	122,374	178,798	193,294	260,350	265,084	322,377	322,377
Total Savings (Avg. MW)	1.25	1.48	5.47	6.75	13.53	13.97	20.41	22.07	29.72	30.26	36.80	36.80

2. "Half-year convention":
Savings resulting from the "Increment" in any year is reduced by 50% in that year as associated projects are completed and start generating savings at different times throughout the first year. This assumption contemplates that associated projects start generating savings half way through the year on average. In the second year and beyond, projects completed in the first year generate savings for the entire year so the "Increment" is credited at 100% for the second year and each successive year.

3) Disaggregate C&I Savings by service level (tariff)

C&I Savings is broken out as:*												
GS-1 Secondary, non demand	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
GS-1 Secondary, demand	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%
GS-1 Primary, non demand	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
GS-1 Primary, demand	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Total C&I	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Electric DSM Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

Rates:

CU4 Fixed Rates: Docket D2009.12.155, Order No. 7075b

	01/01/09	01/01/10	01/01/11	01/01/12	01/01/13	01/01/14
Residential	$0.013273	$0.012734	0.012734	0.012734	0.012734	0.012734
GS-1 Sec Non-Demand	$0.013273	$0.012734	0.012734	0.012734	0.012734	0.012734
GS-1 Sec Demand	$0.013273	$0.012734	0.012734	0.012734	0.012734	0.012734
GS-1 Pri Non-Demand	$0.012910	$0.012385	0.012385	0.012385	0.012385	0.012385
GS-1 Pri Demand	$0.012910	$0.012385	0.012385	0.012385	0.012385	0.012385
GS-2 Substation	$0.012798	$0.012278	0.012278	0.012278	0.012278	0.012278
GS-2 Transmission	$0.012721	$0.012204	0.012204	0.012204	0.012204	0.012204

Calculate CU-4 related DSM Lost Revenues
January - June 2009
Based on Cumulative DSM Savings Since January 2009

Residential	Rate[1]	Gross Program Savings	Adjustment	Net Savings	Estimated Lost Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
Residential	$0.013273	8,072,264	1.00	8,072,264	107,143
				8,072,264	107,143

Commercial & Industrial	Rate[1]	Gross Program Savings	Adjustment	Net Savings	Estimated Lost Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
GS-1 Sec Non-Demand	$0.013273	49,357	1.00	49,357	655
GS-1 Sec Demand	$0.013273	4,837,001	1.00	4,837,001	64,202
GS-1 Pri Non-Demand	$0.012910	0	1.00	0	-
GS-1 Pri Demand	$0.012910	49,357	1.00	49,357	637
GS-2 Substation	$0.012798	0	1.00	0	-
GS-2 Transmission	$0.012721	0	1.00	0	-
			Sub Total General Service:	4,935,715	65,494

Note 1: using rates expected to be in effect at the time (see Rates tab)

Total CU-4-related DSM Lost Revenues Before Stipulation	$ 172,637
Stipulated CU-4-related DSM Lost Revenues	**$ 83,021**

Electric DSM Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

Tracker 2009-10
Based on Cumulative DSM Savings Since January 2009

Residential	Rate[1] ($ per kwh)	Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Bill Line Item					
Residential	$0.012734	37,334,161	1.00	37,334,161	475,413
				37,334,161	475,413

Commercial & Industrial	Rate[1] ($ per kwh)	Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Bill Line Item					
GS-1 Sec Non-Demand	$0.012734	217,888	1.00	217,888	2,775
GS-1 Sec Demand	$0.012734	21,352,982	1.00	21,352,982	271,909
GS-1 Pri Non-Demand	$0.012385	0	1.00	0	-
GS-1 Pri Demand	$0.012385	217,888	1.00	217,888	2,699
GS-2 Substation	$0.012278	0	1.00	0	-
GS-2 Transmission	$0.012204	0	1.00	0	-
		Sub Total General Service:		**21,788,757**	277,382
Note 1: using rates expected to be in effect at the time (see Rates tab)					
		Total CU-4-related DSM Lost Revenues			**$ 752,795**

Tracker 2010-11
Based on Cumulative DSM Savings Since January 2009

Residential	Rate[1] ($ per kwh)	Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Bill Line Item					
Residential	$0.012734	81,225,065	1.00	81,225,065	1,034,320
				81,225,065	1,034,320

Commercial & Industrial	Rate[1] ($ per kwh)	Gross Program Savings (kwh)	Adjustment Factor	Net Savings (kwh)	Estimated Lost Revenue ($)
Bill Line Item					
GS-1 Sec Non-Demand	$0.012734	411,489	1.00	411,489	5,240
GS-1 Sec Demand	$0.012734	40,325,937	1.00	40,325,937	513,510
GS-1 Pri Non-Demand	$0.012385	0	1.00	0	-
GS-1 Pri Demand	$0.012385	411,489	1.00	411,489	5,096
GS-2 Substation	$0.012278	0	1.00	0	-
GS-2 Transmission	$0.012204	0	1.00	0	-
		Sub Total General Service:		**41,148,916**	523,847
Note 1: using rates expected to be in effect at the time (see Rates tab)					
		Total CU-4-related DSM Lost Revenues			**$ 1,558,167**

Electric DSM Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

Tracker 2011-12					
Based on Cumulative DSM Savings Since January 2009					
Residential		**Gross**			**Estimated**
		Program		**Net**	**Lost**
	Rate[1]	**Savings**	**Adjustment**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
Residential	$0.012734	130,374,505	0.89	116,033,309	1,477,568
				116,033,309	1,477,568
Commercial & Industrial		**Gross**			**Estimated**
		Program		**Net**	**Lost**
	Rate[1]	**Savings**	**Adjustment**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
GS-1 Sec Non-Demand	$0.012734	629,198	0.89	559,986	7,131
GS-1 Sec Demand	$0.012734	61,661,361	0.89	54,878,611	698,824
GS-1 Pri Non-Demand	$0.012385	0	0.89	0	0
GS-1 Pri Demand	$0.012385	629,198	0.89	559,986	6,935
GS-2 Substation	$0.012278	0	0.89	0	0
GS-2 Transmission	$0.012204	0	0.89	0	0
		Sub Total General Service:		**55,998,583**	712,891
Note 1: using rates expected to be in effect at the time (see Rates tab)					
		Total CU-4-related DSM Lost Revenues			**$ 2,190,459**

Electric DSM Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

Tracker 2012-13					
Based on Cumulative DSM Savings Since January 2009					
		Reported			
Residential		Gross			Estimated
		Program		Net	Lost
	Rate[1]	Savings	Adjustment	Savings	Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
Residential	$0.012734	172,637,795	0.89	153,647,638	1,956,549
				153,647,638	1,956,549
Commercial & Industrial		Gross			Estimated
		Program		Net	Lost
	Rate[1]	Savings	Adjustment	Savings	Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
GS-1 Sec Non-Demand	$0.012734	924,460	0.89	822,769	10,477
GS-1 Sec Demand	$0.012734	90,597,031	0.89	80,631,358	1,026,760
GS-1 Pri Non-Demand	$0.012385	0	0.89	0	0
GS-1 Pri Demand	$0.012385	924,460	0.89	822,769	10,190
GS-2 Substation	$0.012278	0	0.89	0	0
GS-2 Transmission	$0.012204	0	0.89	0	0
		Sub Total General Service:		82,276,896	1,047,427
Note 1: using rates expected to be in effect at the time (see Rates tab)					
		Total CU-4-related DSM Lost Revenues			$ 3,003,976

Tracker 2013-14					
Based on Cumulative DSM Savings Since January 2009					
		TARGET			
Residential		Gross			Estimated
		Program		Net	Lost
	Rate[1]	Savings	Adjustment	Savings	Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
Residential	$0.012734	206,774,735	0.89	184,029,514	2,343,432
				184,029,514	2,343,432
Commercial & Industrial		Gross			Estimated
		Program		Net	Lost
	Rate[1]	Savings	Adjustment	Savings	Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
GS-1 Sec Non-Demand	$0.012734	1,156,023	0.89	1,028,861	13,102
GS-1 Sec Demand	$0.012734	113,290,270	0.89	100,828,341	1,283,948
GS-1 Pri Non-Demand	$0.012385	0	0.89	0	0
GS-1 Pri Demand	$0.012385	1,156,023	0.89	1,028,861	12,742
GS-2 Substation	$0.012278	0	0.89	0	0
GS-2 Transmission	$0.012204	0	0.89	0	0
		Sub Total General Service:		102,886,062	1,309,792
Note 1: using rates expected to be in effect at the time (see Rates tab)					
		Total CU-4-related DSM Lost Revenues			$ 3,653,224

	A–C	D	E	F	G	H	I	J	K	L	M
1	**Electric DSM Lost Revenues - Dave Gates Generating Station**										
2	**(fixed cost portion of DGGS)**										
3											
4		**Tracker 2010-11**				**Tracker 2011-12**		**Tracker 2012-13**		**Tracker 2013-14**	
5	DSM Targets and Results:	**July-December 2010**		**January-June 2011**		**Period July 2011 – June 2012**		**Period July 2012 – June 2013**		**Period July 2013– June 2014**	
6		**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
7	Annual (Avg. MW)	N/A	N/A	3.00	3.44	6.00	9.31	6.00	7.08	6.00	6.00
8	Cumulative (Avg. MW)	N/A	N/A	3.00	3.44	9.44	12.75	18.75	19.83	25.83	25.83
9											
10											
11	Disaggregate Targets into Residential & Commercial/Industrial [1]										
12		**Tracker 2010-11**				**Tracker 2011-12**		**Tracker 2012-13**		**Tracker 2013-14**	
13		**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
14	% Residential	N/A	N/A	67.4%	75.3%	67.4%	64.9%	69.7%	50.99%	69.7%	69.7%
15	% Commercial & Industrial	N/A	N/A	32.6%	24.7%	32.6%	35.1%	30.3%	49.01%	30.3%	30.3%
16											
17	Incremental Res. (Avg. MW)	N/A	N/A	2.02	2.59	4.04	6.04	4.18	3.61	4.18	4.18
18	Cumulative Res. (Avg. MW)	N/A	N/A	2.02	2.59	6.63	8.63	12.81	12.24	16.42	16.42
19	Incremental C/I (Avg. MW)	N/A	N/A	0.98	0.85	1.96	3.27	1.82	3.47	1.82	1.82
20	Cumulative C/I (Avg. MW)	N/A	N/A	0.98	0.85	2.81	4.12	5.94	7.59	9.41	9.41
21	check fig:	N/A	N/A	3.00	3.44	6.00	9.31	6.00	7.08	6.00	6.00
22											
23	1. Residential/commercial split based on DSM Program results										
24											
25		**Tracker 2010-11**				**Tracker 2011-12**		**Tracker 2012-13**		**Tracker 2013-14**	
26	Cumulative Annual Energy Savings [2]	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
27	Residential (MWH)	N/A	N/A	8,853	11,351	40,408	49,149	93,919	91,413	125,550	125,550
28	C/I (MWH)	N/A	N/A	4,287	3,721	16,016	21,771	44,057	51,297	74,453	74,453
29	Total Savings (MWH)	N/A	N/A	13,140	15,072	56,424	70,920	137,976	142,710	200,003	200,003
30	Total Savings (Avg. MW)	N/A	N/A	1.5	1.7	6.4	8.1	15.8	16.3	22.8	22.8
31											
32	2. "Half-year convention":										
33	Savings resulting from the "Increment" in any year is reduced by 50% in that year as associated projects										
34	are completed and start generating savings at different times throughout the first year. This assumption contemplates that										
35	associated projects start generating savings half way through the year on average. In the second year and										
36	beyond, projects completed in the first year generate savings for the entire year so the "Increment" is credited at 100%										
37	for the second year and each successive year.										
38											
39	Disaggregate C&I Savings by service level (tariff)										
40											
41	C&I Savings is broken out as:										
42	GS-1 Secondary, non demand			1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
43	GS-1 Secondary, demand			98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%
44	GS-1 Primary, non demand			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
45	GS-1 Primary, demand			1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
46	Total C&I			100%	100%	100%	100%	100%	100%	100%	100%
47											
48	**Rates: Source: Appendix E - 05/01/11 Rate Change Revised, Docket D2010.7.74, page 5 of 10**					**2011-12 Tracking Period**					
49	**DGGS Fixed Rate (after losses)**							**2012-13**		**2013-14 Tracking**	
50					01/01/11	July-Dec 2011	Jan-June 2012	**Tracking Period**		**Period**	
51	Residential				0.004600	0.004018	0.004795	0.004795		0.004795	
52	GS-1 Sec Non-Demand				0.004600	0.004018	0.004795	0.004795		0.004795	
53	GS-1 Sec Demand				0.004600	0.004018	0.004795	0.004795		0.004795	
54	GS-1 Pri Non-Demand				0.004474	0.003908	0.004664	0.004664		0.004664	
55	GS-1 Pri Demand				0.004474	0.003908	0.004664	0.004664		0.004664	
56	GS-2 Substation				0.004435	0.003874	0.004624	0.004624		0.004624	
57	GS-2 Transmission				0.004409	0.003851	0.004596	0.004596		0.004596	

Electric DSM Lost Revenues - Dave Gates Generating Station

(fixed cost portion of DGGS)

January-June 2011

Based on INCREMENTAL DSM Savings Since January 2011

Residential					
		Gross			Estimated
		Program		Net	Lost
	Rate[1]	Savings	Adjustment	Savings	Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
Residential	$0.004600	11,350,635	1.00	11,350,635	52,213
				11,350,635	52,213

Commercial & Industrial					
		Gross			Estimated
		Program		Net	Lost
	Rate[1]	Savings	Adjustment	Savings	Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
GS-1 Sec Non-Demand	$0.004600	37,214	1.00	37,214	171
GS-1 Sec Demand	$0.004600	3,646,988	1.00	3,646,988	16,776
GS-1 Pri Non-Demand	$0.004474	0	1.00	0	-
GS-1 Pri Demand	$0.004474	37,214	1.00	37,214	166
GS-2 Substation	$0.004435	0	1.00	0	-
GS-2 Transmission	$0.004409	0	1.00	0	-
		Sub Total General Service:		3,721,416	17,114
	Total DGGS-related DSM Lost Revenues				$ 69,327

July 2011-June 2012

Based on INCREMENTAL DSM Savings Since January 2011

Residential					
		Gross			Estimated
	Average	Program		Net	Lost
	Rate[1]	Savings	Adjustment	Savings	Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
Residential	$0.004407	49,149,440	0.89	43,743,001	192,754
				43,743,001	192,754

Commercial & Industrial					
		Gross			Estimated
	Average	Program		Net	Lost
	Rate[1]	Savings	Adjustment	Savings	Revenue
Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
GS-1 Sec Non-Demand	$0.004407	217,708	0.89	193,760	854
GS-1 Sec Demand	$0.004407	21,335,423	0.89	18,988,527	83,673
GS-1 Pri Non-Demand	$0.004286	0	0.89	0	-
GS-1 Pri Demand	$0.004286	217,708	0.89	193,760	830
GS-2 Substation	$0.004249	0	0.89	0	-
GS-2 Transmission	$0.004224	0	0.89	0	-
		Sub Total General Service:		19,376,048	85,357
	Total DGGS-related DSM Lost Revenues				$ 278,111

Note 1: Two sets of rates were used, each set was effective for 6 months of the 2011-12 tracker period

Electric DSM Lost Revenues - Dave Gates Generating Station

(fixed cost portion of DGGS)

July 2012-June 2013					
Based on INCREMENTAL DSM Savings Since January 2011					
Residential		**Gross**			**Estimated**
		Program		**Net**	**Lost**
	Rate[1]	**Savings**	**Adjustment**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
Residential	$0.004795	91,412,730	0.89	81,357,330	390,108
				81,357,330	390,108
Commercial & Industrial		**Gross**			**Estimated**
		Program		**Net**	**Lost**
	Rate[1]	**Savings**	**Adjustment**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
GS-1 Sec Non-Demand	$0.004795	512,970	0.89	456,544	2,189
GS-1 Sec Demand	$0.004795	50,271,094	0.89	44,741,274	214,534
GS-1 Pri Non-Demand	$0.004664	0	0.89	0	-
GS-1 Pri Demand	$0.004664	512,970	0.89	456,544	2,129
GS-2 Substation	$0.004624	0	0.89	0	-
GS-2 Transmission	$0.004596	0	0.89	0	-
		Sub Total General Service:		**45,654,361**	218,853
		Total DGGS-related DSM Lost Revenues			**$ 608,961**

July 2013-June 2014					
Based on INCREMENTAL DSM Savings Since January 2011					
		TARGET			
Residential		**Gross**			**Estimated**
		Program		**Net**	**Lost**
	Rate[1]	**Savings**	**Adjustment**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
Residential	$0.004795	125,549,670	0.89	111,739,206	535,789
				111,739,206	535,789
Commercial & Industrial		**Gross**			**Estimated**
		Program		**Net**	**Lost**
	Rate[1]	**Savings**	**Adjustment**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
GS-1 Sec Non-Demand	$0.004795	744,534	0.89	662,635	3,177
GS-1 Sec Demand	$0.004795	72,964,333	0.89	64,938,257	311,379
GS-1 Pri Non-Demand	$0.004664	0	0.89	0	-
GS-1 Pri Demand	$0.004664	744,534	0.89	662,635	3,091
GS-2 Substation	$0.004624	0	0.89	0	-
GS-2 Transmission	$0.004596	0	0.89	0	-
		Sub Total General Service:		**66,263,527**	317,647
		Total DGGS-related DSM Lost Revenues			**$ 853,436**

Electric DSM Lost Revenues - Spion Kop

(fixed cost portion of Spion Kop)

	A / B / C	D	E	F	G
4		Tracker 2012-13		Tracker 2013-14	
5	DSM Targets and Results:	December 1, 2012 - June 30, 2013		Period July 2013 – June 2014	
6		Target	Reported	Target	Reported
7	Annual (Avg. MW)	6.00	4.11	6.00	6.00
8	Cumulative (Avg. MW)	6.00	4.11	10.11	10.11
9					
10		Commercial online date for Spion Kop was December 1, 2012. Reported energy savings has been "de-rated" for the 5 months July-Nov. 2012 (153 days).			
11	Disaggregate Targets into Residential & Commercial/Industrial [1]				
12					
13		Target	Reported	Target	Reported
14	% Residential	67.4%	50.99%	69.7%	69.7%
15	% Commercial & Industrial	32.6%	49.01%	30.3%	30.3%
16					
17	Incremental Res. (Avg. MW)	4.04	2.10	4.18	4.18
18	Cumulative Res. (Avg. MW)	4.04	2.10	6.28	6.28
19	Incremental C/I (Avg. MW)	1.96	2.02	1.82	1.82
20	Cumulative C/I (Avg. MW)	1.96	2.02	3.83	3.83
21	check fig:	6.00	4.11	6.00	6.00
22					
23	1. Residential/commercial split based on DSM Program results				
24					
25					
26	Cumulative Annual Energy Savings[2]	Target	Reported	Target	Reported
27	Residential (MWH)	17,707	9,186	36,693	36,693
28	C/I (MWH)	8,573	8,827	25,613	25,613
29	Total Savings (MWH)	26,280	18,013	62,306	62,306
30	Total Savings (Avg. MW)	3.0	2.1	7.1	7.1
31					
32	2. "Half-year convention":				
33	Savings resulting from the "Increment" in any year is reduced by 50% in that year as associated projects				
34	are completed and start generating savings at different times throughout the first year. This assumption contemplates that				
35	associated projects start generating savings half way through the year on average. In the second year and				
36	beyond, projects completed in the first year generate savings for the entire year so the "Increment" is credited at 100%				
37	for the second year and each successive year.				
38					
39	Disaggregate C&I Savings by service level (tariff)				
40					
41	C&I Savings is broken out as:				
42	GS-1 Secondary, non demand	1%	1%	1%	1%
43	GS-1 Secondary, demand	98%	98%	98%	98%
44	GS-1 Primary, non demand	0%	0%	0%	0%
45	GS-1 Primary, demand	1%	1%	1%	1%
46	Total C&I	100%	100%	100%	100%
47					
48	**Spion Kop Rates**				
49	**Docket D2012.7.75**	**December 1, 2012 - June 30, 2013**		**Period July 2013 – June 2014**	
50					
51	Residential	0.001047		$0.001257	
52	GS-1 Sec Non-Demand	0.001048		$0.001258	
53	GS-1 Sec Demand	0.001048		$0.001258	
54	GS-1 Pri Non-Demand	0.001020		$0.001224	
55	GS-1 Pri Demand	0.001020		$0.001224	
56	GS-2 Substation	0.001011		$0.001214	
57	GS-2 Transmission	0.001005		$0.001206	

Row	B	C	D	E	F	G
58						
59	**December 1, 2012 - June 30, 2013**					
60						
61						
62	**Residential**		Gross			Estimated
63			Program		Net	Lost
64		Rate	Savings	Adjustment	Savings	Revenue
65	Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
66	Residential	$0.001047	9,185,768	0.89	8,175,334	$ 8,560
67					8,175,334	$ 8,560
68						
69	**Commercial & Industrial**		Gross			Estimated
70			Program		Net	Lost
71		Rate	Savings	Adjustment	Savings	Revenue
72	Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
73	GS-1 Sec Non-Demand	$0.001048	88,274	0.89	78,564	$ 82
74	GS-1 Sec Demand	$0.001048	8,650,891	0.89	7,699,293	$ 8,069
75	GS-1 Pri Non-Demand	$0.001020	0	0.89	0	$ -
76	GS-1 Pri Demand	$0.001020	88,274	0.89	78,564	$ 80
77						
78	GS-2 Substation	$0.001011	0	0.89	0	$ -
79	GS-2 Transmission	$0.001005	0	0.89	0	$ -
80			Sub Total General Service:		7,856,421	$ 8,231
81						
82			Total Spion Kop-related DSM Lost Revenues			$ 16,791
83						

Row	B	C	D	E	F	G
84	**July 2013-June 2014**					
85						
86						
87	**Residential**		Gross			Estimated
88		Average	Program		Net	Lost
89		Rate	Savings	Adjustment	Savings	Revenue
90	Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
91	Residential	$0.001257	36,693,357	0.89	32,657,087	41,050
92					32,657,087	41,050
93						
94	**Commercial & Industrial**		Gross			Estimated
95		Average	Program		Net	Lost
96		Rate	Savings	Adjustment	Savings	Revenue
97	Bill Line Item	($ per kwh)	(kwh)	Factor	(kwh)	($)
98	GS-1 Sec Non-Demand	$0.001258	256,131	0.89	227,956	287
99	GS-1 Sec Demand	$0.001258	25,100,798	0.89	22,339,711	28,103
100	GS-1 Pri Non-Demand	$0.001224	0	0.89	0	-
101	GS-1 Pri Demand	$0.001224	256,131	0.89	227,956	279
102						
103	GS-2 Substation	$0.001214	0	0.89	0	-
104	GS-2 Transmission	$0.001206	0	0.89	0	-
105			Sub Total General Service:		22,795,623	28,669
106						
107			Total Spion Kop-related DSM Lost Revenues			$ 69,719
108						
109						

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NorthWestern Energy
Electric Utility Derivation of Rates
Spion Kop
Year 2013

Customer Rate Class	Loss Factor	Dec12 to Nov13 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	Spion Kop Fixed Rate After Losses	Spion Kop Fixed Revenue Check
Residential	8.5100%	2,362,571,006	2,362,571,006	2,563,625,799	$ 0.001047	$ 2,473,612
Residential Employee	8.5100%	3,786,173	2,271,704	2,465,026	$ 0.000628	$ 2,378
GS 1 Secondary NonDemand	8.5100%	274,329,840	274,329,840	297,675,310	$ 0.001048	$ 287,498
GS 1 Secondary Demand	8.5100%	2,449,898,973	2,449,898,973	2,658,385,376	$ 0.001048	$ 2,567,494
GS 1 Primary NonDemand	5.5400%	561,768	561,768	592,889	$ 0.001020	$ 573
GS 1 Primary Demand	5.5400%	350,542,637	350,542,637	369,962,699	$ 0.001020	$ 357,553
General Service Substation	4.6300%	244,005,756	244,005,756	255,303,222	$ 0.001011	$ 246,690
General Service Transmission	4.0000%	132,300,021	132,300,021	137,592,022	$ 0.001005	$ 132,962
Irrigation	8.5100%	83,490,261	83,490,261	90,595,283	$ 0.001048	$ 87,498
Lighting	8.5100%	57,821,458	57,821,458	62,742,064	$ 0.001048	$ 60,597
		5,959,307,893	5,957,793,424	6,438,939,689	$ 0.001043	$ 6,216,854
YNP Contract		18,457,300			Rounding Adjustment	$ 506
Total Electric Supply Load		5,977,765,193				$ 6,217,360
		-				

Spion Kop First-year Revenue Requirement [1]	$ 6,217,360
Total Spion Kop Fixed Rate Before Losses	**$ 0.000966**
Total Spion Kop Fixed Rate After Losses	**$ 0.001043**

[1] Source: Appendix G Dec 2012.
file name: Appendix H First Year 2013.xlsx

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NorthWestern Energy
Electric Utility Derivation of Rates
Spion Kop
Year 2014

Customer Rate Class	Loss Factor	Dec12 to Nov13 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	Spion Kop Fixed Rate After Losses	Spion Kop Fixed Revenue Check
Residential	8.5100%	2,362,571,006	2,362,571,006	2,563,625,799	$ 0.001467	$ 3,465,892
Residential Employee	8.5100%	3,786,173	2,271,704	2,465,026	$ 0.000880	$ 3,332
GS 1 Secondary NonDemand	8.5100%	274,329,840	274,329,840	297,675,310	$ 0.001468	$ 402,716
GS 1 Secondary Demand	8.5100%	2,449,898,973	2,449,898,973	2,658,385,376	$ 0.001468	$ 3,596,452
GS 1 Primary NonDemand	5.5400%	561,768	561,768	592,889	$ 0.001428	$ 802
GS 1 Primary Demand	5.5400%	350,542,637	350,542,637	369,962,699	$ 0.001428	$ 500,575
General Service Substation	4.6300%	244,005,756	244,005,756	255,303,222	$ 0.001416	$ 345,512
General Service Transmission	4.0000%	132,300,021	132,300,021	137,592,022	$ 0.001407	$ 186,146
Irrigation	8.5100%	83,490,261	83,490,261	90,595,283	$ 0.001468	$ 122,564
Lighting	8.5100%	57,821,458	57,821,458	62,742,064	$ 0.001468	$ 84,882
		5,959,307,893	5,957,793,424	6,438,939,689	$ 0.001462	$ 8,708,872
YNP Contract		18,457,300			Rounding Adjustment	$ 5,865
Total Electric Supply Load		5,977,765,193				$ 8,714,738
		-				

Spion Kop Second-year Revenue Requirement [1]	$ 8,714,738
Total Spion Kop Fixed Rate Before Losses	**$ 0.001353**
Total Spion Kop Fixed Rate After Losses	**$ 0.001461**

[1] Source: Appendix G Dec 2012.
file name: Appendix H Second Year 2014.xlsx

2013-2014 Spion Kop AVERAGE Fixed Rate After Losses	
Residential	$ 0.001257
Residential Employee	$ 0.000754
GS 1 Secondary NonDemand	$ 0.001258
GS 1 Secondary Demand	$ 0.001258
GS 1 Primary NonDemand	$ 0.001224
GS 1 Primary Demand	$ 0.001224
General Service Substation	$ 0.001214
General Service Transmission	$ 0.001206
Irrigation	$ 0.001258
Lighting	$ 0.001258
	$ 0.001253

NorthWestern® Energy

2013 DSM / USB Communications Plan

NorthWestern Energy offers a broad selection of energy efficiency, renewable energy, and low income programs and services funded by customers through electric and natural gas supply rates and the electric and natural gas Universal System Benefits Charges (USBC). The energy savings resulting from these programs are a key piece of NorthWestern Energy's supply portfolio.

The electric and natural gas resource acquisition targets for these programs are set forth in the supply portfolio plans filed with the Montana Public Service Commission (MPSC).

Program offerings have stabilized in the past couple of years. Compact Fluorescent Lights (CFLs) continue to contribute a significant portion of the electric savings in recent years. Savings from the commercial and industrial markets have not grown as rapidly.

A comprehensive independent evaluation of all NorthWestern Energy demand side management (DSM) and Universal System Benefits (USB) programs was completed in 2012. The evaluation concluded that NorthWestern Energy's programs deliver cost effective natural gas and electric savings, are well-run, and follow more than 50 best practices. The evaluation provided specific recommendations for program changes, some of which relate to communication, education, and marketing. Recommendations are being incorporated into the 2013 communications plan as appropriate and applicable.

Nationally and locally, attention to energy efficiency, renewable energy, and "green" or sustainable energy has continued.

The DSM targets and the heightened awareness of "green" help frame the need and opportunities set forth in this communications plan. The plan is intended to be an active, adaptive product—one that can be filed with the MPSC as part of the implementation strategies to achieve the DSM targets and can be modified to meet current needs and opportunities.

The plan is implemented consistent with NorthWestern Energy E+ graphics and image standards and strategies.

When referring to DSM in this plan, both DSM activities funded with supply rates and USB activities funded with the USBC are included. Generally, DSM refers to both activities but where appropriate, USB has been specifically broken out.

The plan refines and sustains residential, low income, and renewable generation communications strategies and continues the acceleration of communication for commercial/industrial programs. The following table lists the programs by customer sector addressed in the plan.

Table 1: DSM Programs

EFFICIENCY PLUS (E+) PROGRAM		
ELECTRIC PROGRAMS	**NATURAL GAS PROGRAMS**	**CUSTOMER SECTOR**
E+ Audit for the Home	E+ Audit for the Home	Residential
E+ Residential Lighting		Residential
E+ Residential Rebates Program—Existing Homes	E+ Residential Rebates Program—Existing Homes	Residential
E+ Residential New Homes Program	E+ Residential New Homes Program	Residential
E+ Free Weatherization/Fuel Switch	E+ Free Weatherization	Residential
E+ Appraisal for Small Business		Commercial
E+ Commercial Lighting Rebate		Commercial/Industrial
E+ Business Partners Electric	E+ Business Partners Natural Gas	Commercial/Industrial
E+ Business Partners –Irrigation		Agriculture
E+ Commercial Savings-New Construction	E+ Commercial Savings-New Construction	Commercial /Industrial
E+ Commercial Savings-Existing Facilities	E+ Commercial Savings-Existing Facilities	Commercial /Industrial
E+ Green Motor Rewind Instant Rebate		Commercial/Industrial /Agriculture
E+ Renewable Generation		All
E+ Green Power (Communications, not resource)		All
Northwest Energy Efficiency Alliance (NEEA)		All

The DSM programs are not offered to Large USB Electric Choice customers or to Natural Gas Choice customers so these customers are not targeted in the plan.

The DSM Communications Plan is intended as a guide to identify and direct the communications strategies associated with the implementation of NorthWestern Energy's DSM programs. The plan will be modified as needed to suit changing opportunities and conditions.

GOAL

Effectively and efficiently market DSM programs to achieve defensible natural gas and electric resource acquisition results for the supply portfolios through NorthWestern Energy employees and its program contractors, and by generating increased public awareness of the programs and the opportunities to save energy.

OBJECTIVES

- Engage trade ally community and public entities to incorporate energy efficiency in their messages and marketing
- Engage customers to demand energy efficiency from service providers
- Build participation with emphasis on commercial/industrial DSM sector projects

AUDIENCES

- NorthWestern Energy employees
- NorthWestern Energy program contractors and partner contractors
- Commercial and industrial sector customers (electric and natural gas supply)
- Residential customers (gas and electric supply)
- Trade Allies: electrical vendors—i.e. Crescent Electric, Grainger, WesCo, CED; service providers—electricians, refrigeration, HVAC, motors, architects, engineers, insulation; distributors—lighting, equipment; retailers—of CFLs, building supplies, appliances, air sealing, and water measures; building contractors and general contractors; HVAC and insulation contractors; trade associations—i.e. AIA, ASHRAE, Montana Hospital Association, Montana Hospitality and Lodging Association.
- Public officials and government departments
- Media—mass and trades
- Related organizations

IMPLEMENTATION STRATEGIES

NorthWestern Energy will engage its employees, program implementation representatives, and program/partner contractors to utilize existing and new methods and tools to cultivate customer participation in the DSM programs.

Implementation tactics are targeted by customer sector and directed at defined audiences in most cases. Cross-marketing of programs within the customer sector is incorporated as appropriate. A general calendar of implementation tactics by quarter, sector, program and audience is provided.

TACTICS

Residential Programs

- Update program materials/resources (Web and Brochures)
- Coordinate display materials for Home Shows (Spring Shows run February – May; Farmers' Markets in the summer, selected Fall Shows run September-October)
- Update and execute natural gas program campaign
- Develop updated program-at-a-glance summary
- CFL instant coupon offerings to increase installation of CFLs, incorporating the educational messages into various residential lighting outreach activities (direct mail, tradeshows, events)
- Target direct mail and limited media for E+ Audits for the Home with cross marketing of Energy Appraisal
- Continue contacts by program contractors/community relations managers (CRMs)
- Update Customer Service Representative (CSR) training for new CSRs
- Messages in Energy Connections and news releases regarding saving energy
- Incorporate energy efficient products into contest offerings for customers
- Participate in local events as appropriate
- Contact various program trade allies with updates and solicitations of new trade allies (Preferred Contractors, lighting retailers, homebuilding associations)

Commercial/Industrial Programs

- Update existing program materials/resources (web and brochures) to incorporate program additions and changes
- Develop new materials (brochure copy, case studies, feature articles, etc.) Execute new project case studies on commercial/industrial customers
- Integrate commercial program messages into tradeshow displays

- Continue customer and trade ally contacts by program/partner contractors and CRMs
- Participate in local events where appropriate
- Targeted outreach for customer/trade ally training and partnership opportunities
- Review and update trade ally databases
- Update program-at-a-glance summary
- Update web resources with program changes and additions

METHODS/TOOLS

Residential Sector

Residential family of Program Brochures that describe individual program and cross-market same sector programs and highlight resources for more information directing customers to website or program contact phone numbers. GENERAL AUDIENCES

Web/interactive media tools Efficiency Plus (E+) web section of www.northwesternenergy.com, Facebook, and Search Engine Marketing (SEM), microsites such as MYCORNERCONTEST.COM for the Earth Day photo contest. GENERAL AUDIENCES

Internal Communications throughout the year such as FYI, TEAM, iConnect, emails, employee training sessions, etc. to inform all or targeted groups of employees of programs, featured projects/promotions, training, and events. EMPLOYEES

Billing messages in the message box of the NorthWestern Energy billing statement and in Energy Connections to encourage program participation. RESIDENTIAL CUSTOMERS

Direct Mail to Trade Allies and targeted customers of individual program offering and related trainings along with cross-marketing of other programs. TARGETED FOR INDIVIDUAL MAILING

One-on-one by program representatives, program contractors, CRMs, CSRs – communicate residential program offerings based upon opportunity and direct to appropriate resources. May include interactions during: E+ Audit for the Home, tradeshow discussions, customer care calls, or normal company interactions with the customer. OPPORTUNITY DRIVEN

One-to-Many through speakers' bureaus, service organization presentations by program contractors and CRMs to increase awareness of programs and opportunities to save energy. COMPANY OR CUSTOMER INITIATED

Home Improvement Shows, Farmers' Markets, Parade of Homes, community events to reach targeted audiences with information about programs and opportunities and, as appropriate, distribute CFLs. COMPANY OR ORGANIZATION INITIATED

Trade Association Events, publications, and websites to target presentations, displays and messages about opportunities for customers to save energy and the programs that NorthWestern Energy offers. TARGETED TRADE ALLIES OR CUSTOMER GROUP

Targeted media advertising tied to special campaigns, programs or events. TARGETED TO ELIGIBLE RESIDENTIAL AUDIENCE

Earned media feature stories on projects and opportunities in trade or mass media. GENERAL AUDIENCE WITH EMPHASIS ON ELIGIBLE AUDIENCE.

Customer contests provide customer awards tied to energy efficient products such as most efficient Energy Forward ENERGY STAR televisions as part of Earth Day photo customer contest. GENERAL AUDIENCE

Customer E-Newsletter Pilot to subset of residential customers to include information about programs, tips on efficiency, and events throughout the year. TARGETED RESIDENTIAL CUSTOMERS

Commercial/Industrial Sector

Commercial/Industrial family of Program Brochures that describe individual program and cross-market same sector programs and highlight resources for more information directing customers to website or program contact phone numbers. GENERAL AUDIENCES

Web/interactive media tools— Efficiency Plus (E+) web section of www.northwesternenergy.com, SEM, microsites as appropriate. GENERAL AUDIENCES

Internal Communications throughout the year such as FYI, TEAM, i-Connect, e-mails, CSR trainings, etc. to inform all or targeted groups of employees of programs, featured projects/promotions, training, and events. EMPLOYEES AND PROGRAM PARTNERS AS APPROPRIATE

Case Studies of E+ Business Partners, substantial E+ Commercial Lighting Rebate Program, or other E+ Rebate projects to demonstrate various types of customer participation and customer benefits. TARGETED TRADE ALLIES AND KEY CONTACTS AND TARGETED CUSTOMERS

Direct Mail to Trade Allies and targeted customers of individual program offering and related trainings along with cross-marketing of other programs. TARGETED FOR INDIVIDUAL MAILING

Customer Care E-Newsletter to key customers will include information about programs, training, and case studies throughout the year. COMMERCIAL CUSTOMERS AND TRADE ALLIES

One-on-one by program representatives, program contractors, CRMs, and CSRs – communicate commercial and industrial program offerings based upon opportunity and direct to appropriate resources. May include interactions during: E+ Energy Appraisal, informal facility assessment, project completion review, cold calls, trade ally visits, or normal company interactions with the customer. OPPORTUNITY DRIVEN

One-to-Many through speakers' bureaus, service organization presentations by program contractors and CRMs to increase awareness of programs and opportunities to save energy. COMPANY OR CUSTOMER INITIATED

Vendor breakfast/Brown Bags/After Hour events/Community Events to reach targeted audiences with information about programs and opportunities. COMPANY OR ORGANIZATION INITIATED

Trade Association Events, publications, and websites to target presentations, displays and messages about opportunities for customers to save energy and the programs that NorthWestern Energy offers. Northwestern Energy Lighting Trade Ally Network is an example of an activity that provides technical training and cultivates trade ally participation in programs. TARGETED TRADE ALLY OR CUSTOMER GROUP

Targeted media advertising tied to events, projects, or programs. Continuing E+ Commercial Lighting Rebate program advertising through television and radio to promote lighting as a universal way for businesses to save energy. GENERAL AUDIENCE WITH EMPHASIS ON COMMERCIAL LIGHTING OR OTHER SPECIFIC PROJECT-RELATED AUDIENCES

Earned media feature stories on projects and opportunities in trade or mass media. GENERAL AUDIENCE WITH EMPHASIS ON SPECIFIC PROJECT-RELATED AUDIENCES

Supporting commercial program contractors with consistent marketing materials to describe working relationship with NorthWestern Energy. GENERAL COMMERCIAL CUSTOMERS AND TRADE ALLIES AS IDENTIFIED BY PROGRAM CONTRACTORS.

NorthWestern Energy has defined an overall budget for marketing and communication for the electric and natural gas DSM programs of $1M. This includes mass media development and placement as well as all other marketing expenses.

MEASUREMENT

Measurement of this communications plan will be achieved through program participation in comparison to the resource acquisition goals set forth in the supply plans filed with the MPSC.

The DSM targets are based on a July 1 – June 30 year. USB programs operate on Calendar year.

Other supporting measurement will be gathered through existing customer and employee survey tools, tracking of participation in comparison to past performance.

Attached is a calendar for 2013 which will be modified based upon opportunities and needs.

DSM Program Communications Calendar

	A	B	C	D	E	F	G	H	I	J	K	L	M	P
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	Campaign/Initiative	MO	Implement-ation Dates	E	G	Audience	Message	Media	Internal (includes employees and key contractors)	Web	Hard Materials	Jan
2	R0x	**Residential**												
3	R0x	**Tips--Electric (update)**	Spot media and Campaigns			x		Residential electric customers	Act to save electricity; check out programs	Television; radio		Tips	Brochure	
4	R0x	**Tips--Natural Gas (update)**	Spot media and Campaigns				x	Residential natural gas customers	Act to save natural gas; check out programs	Television; radio		Tips	Brochure	
5	R1x	***Residential Audits***			On-going	x	x	Residential space or water heating customers whose home has not previously been audit (home 5 yrs old or older), Residential electric baseload customers	Call to Action--Schedule an Audit; follow-up on recommendations	2 Xs /Year Energy Connections--more as needed; news releases as needed; bill statement messages; direct mail to targeted customers	CSR, CRM reminders of qualifications	*On-going description, contact, qualifications; Facebook outreach*	Tradeshow and event handouts/sign-ups/display/brochures of all residential programs/resources in audit packets	
6	R1x	Outreach	Targeted Direct Mail	Mar Sept	Mar -- more as needed		x	Residential natural gas customers who've not previously had an audit	Call to Action--Schedule an Audit; follow-up on recommendations	Direct Mail/ reinforcing press release	E-mail notice of mailing		Direct Mail	
7	R1x	Electric Baseload	Targeted Direct Mail		On-going	x		Residential electric baseload customers	Call to Action--Complete Energy Usage survey; follow-up on recommendations	Direct Mail			Direct Mail Non-NWE production	
8	R2x	***E+ Home Lighting -- CFLs***	*Campaign Focus on Education--opportunities to save electricity*		*On-going*	x		Residential electric customers	Call to Action--Install CFLs in High Use Locations (Educate--4L's)	Multiple Xs Energy Connections; Direct Mail, Radio, Newspaper, billboard, micro-web site, web advertising, events, Spot TV		*Mail-in offer, education messages, reinforce special offers/events, list participating retailers*	*Tradeshow Display/Retailer support & POP*	
9	R2x	Mail-in Rebate Offer	Web, Audits, Distribution Events, Energy Connections		On-going	x		Residential electric customers	Call to Action--Install CFLs in High Use Locations (Educate--4L's) offer up to $2 off for up to 15 CFLs			on-line application	Brochure	
10	R2a	Spring Trade Shows a)	CFL distribution (Missoula, Billings, Helena, Great Falls, Butte); Displays; promote all appropriate programs	Feb	Feb - May	x		Residential electric customers	Call to Action--Install CFLs in High Use Locations (Educate--4L's)	Spot Newspaper/TV	local market e-mail	List in events/training/ workshops?	Canvas Bags, Brochures/Signage	
11	R2x	E+ Home Lighting -- CFLs Spring Intant Coupon Offer	Direct Mail to residential electric customers for up to $2 off on CFLs from Participating Retailers	Apr	Apr 22-Jun 16	x		Residential electric customers	Call to Action--Buy from participating retailers. Ltd time offer. Install CFLs in High Use Locations (Educate--4L's)	Multiple Xs Energy Connections; Direct Mail, Radio, Newspaper, billboard, micro-web site, web advertising, events, Spot TV, Retailer	e-mail of mailing and qualifications	Reference, list of participating retailers	see media	
12	R2x	Farmers' Market	CFL Distribution Events	Jul	Jul- Aug	x		Residential electric customers who've not rec'd Free CFLs at event earlier in year	Call to Action--Install CFLs in High Use Locations (Educate--4L's)	Newspaper, spot Radio	local market e-mail	List in events/training/work shops?		

DSM Program Communications Calendar

	A	B	C	D	E	F	G	H	I	J	K	L	M	P
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	Campaign/Initiative	MO	Implement-ation Dates	E	G	Audience	Message	Media	Internal (includes employees and key contractors)	Web	Hard Materials	Jan
13	R2a	Fall Trade Shows a)	Displays, all programs, CFL distribution (Missoula, Billings, Bozeman?, Helena?, Great Falls, Butte)	Sep	Sep - Oct	x		Residential electric customers who've not rec'd Free CFLs at event earlier in year	Call to Action--Install CFLs in High Use Locations (Educate--4L's)	Spot Newspaper	local market e-mail	List in events/training/work shops?	Canvas Bags, Brochures/Signage	
14	R2x	Regional Buy downs	Review POP/agreements for Regional efforts	Jan	Jan- Dec	x		Residential electric customers	Call to Action for specialty CFLs	POP/Retailer ed		Info on specialty CFLs and retailers		
15	R2x	E+ Home Lighting -- CFLs Fall Instant Coupon Offer	Direct Mail to residential electric customers for up to $2 off on CFLs from Participating Retailers	Oct	Tentative Oct 1 - Nov 15	x		Residential electric customers	Call to Action--Buy from participating retailers. Ltd time offer. Install CFLs in High Use Locations (Educate--4L's)	Multiple Xs Energy Connections; Direct Mail, Radio, Newspaper, billboard, micro-web site, web advertising, events, Spot TV, Retailer	e-mail of mailing and qualifications	Reference, list of participating retailers	see media	
16	R3x	***E+ Gas Savings for the Home***	Promote Rebates for homes with natural gas space or water heat		On-going		x	Residential natural gas space and water heating customers (New or Existing Homes)	Call to Action--Install qualifying measures for rebates (Insulation, Programmable Thermostats, High Efficiency heating or water Equipment replacements, heating system retrofit	2 Xs /Year Energy Connections--more as needed		Description of Rebate offers, forms, preferred contractor lists (Heating Contractors/Insula-tion Contractors)	General Brochure, description, application, preferred installers /Display materials / supporting Preferred Contractor advertising	
17	R3x	Gas Savings Mass Media Campaign 1	Mass Media targeted at residential natural gas customers	Aug	Q 3-4		x	Residential natural gas space or water heating customers	Call to Action--Install qualifying measures for rebates	spot TV, Radio,		Call to Action	General description, application, preferred installers, supporting preferred Contractor advertising	
18	R3a	Spring Tradeshows a)	Program Education in Natural Gas markets	Feb	Feb- May		x	Residential natural gas space or water heating customers	Call to Action--Install qualifying measures for rebates		local market e-mail	Call to Action	Displays/brochures program materials	
19	R3a	Fall Tradeshows a)	Program Education in Natural Gas markets	Sep	Sep- Oct		x	Residential natural gas space or water heating customers	Call to Action--Install qualifying measures for rebates		local market e-mail	Call to Action	Displays/brochures program materials	
20	R0x	Special Events--CSR Training, Game Days	Promote natural gas energy efficiency programs in existing homes, partners with local allies,		As needed	x	x	Residential natural gas space or water heating customers in existing homes; targeted Events	Call to Action--Participate in programs; priotitize measures; Install qualifying measures for rebates;	Spot newspaper; news releases as appropriate	CSR and local e-mails as appropriate	Schedule on site	Educational brochures; signage; displays; presentations	
21	R4x	***E+ New Homes***	Promote energy efficiency in new homes, rebates for qualifying measures, rebates for Energy Star manufactured homes; Training/promote Northwest Energy Star Homes/builders; new MT Code			x	x	Residential customers building new homes		Energy Connections	E-mail of program qualifications and links; Training	Rebate forms, link to all Energy Star builders, Energy Star support; training events	Publications for Trade Associations	

DSM Program Communications Calendar

	A	B	C	D	E	F	G	H	I	J	K	L	M	P
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	Campaign/Initiative	MO	Implement-ation Dates	E	G	Audience	Message	Media	Internal (includes employees and key contractors)	Web	Hard Materials	Jan
22	R4x	E+ New Homes Natural Gas	Promote natural gas energy efficiency in new homes, rebates for qualifying measures, training/promote Northwest Energy Star Homes; new MT Code	Sep	Sep and as approp.		x	Residential natural gas customers building new homes	Call to Action--install high efficiency heating or water heating measures; Northwest Energy Star manufactured homes	Special Publication, Newspaper at Parade of Homes		Schedule/homes, Rebate forms, link to all Energy Star builders, Energy Star support	Brochures/Signage as needed	
23	R4x	E+ New Homes Electric	Rebates for CFLs and Fixtures or Northwest Energy Star electrically heated manufactured homes, and information about Northwest Energy Star Homes; Train/promote NW Energy Star Homes/Builders; new	Sep	Sep and as approp.	x		Residential Electric Customers building new homes	Call to Action--Include ENERGY STAR lighting in new homes; Northwest Energy Star homes/builders	Special Publication, Newspaper at Parade of Homes		Schedule/homes, Rebate forms, link to all Energy Star builders, Energy Star support	Brochures/Signage as needed	
24	R4x	***E+ Residential Electric Savings***	Promote energy efficiency in homes with electric space or water heat; efficient appliances; electronics		as needed	x		Residential Electric customers in existing homes	Call to Action--Install qualifying efficiency measures	trade ally		Description of Rebate offers, forms, preferred contractor lists (Heating Contractors/Insulation Contractors)	Brochure/forms/application as needed	
25	R6x	**E+ Free Weatherization**	Supportive advertising for low income energy assistance--	Sep	Sep - Apr as needed	x	x	Income Qualified space or water heating customers for free Audit and installation of qualifying measures (LIEAP qualified) also receive NWE low income discount; may qualify for Energy Share	Call to Action--Apply for LIEAP as soon as possible to receive LIEAP and heating season discounts; and potentially qualify for free weatherization. Income Guidelines have been relaxed.	Energy Connections; Newspaper; radio , September? news release on NWE programs & funding		Description of program/discount and refer customers to Human Resource Councils to apply.	energy efficiency education materials	

DSM Program Communications Calendar

	A	B	C	D	E	F	G	H	I	J	K	L	M	P
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	Campaign/Initiative	MO	Implement-ation Dates	E	G	Audience	Message	Media	Internal (includes employees and key contractors)	Web	Hard Materials	Jan
26														
27	C0	Commercial *											PowerPoint presentation for internal and key contractor use; Messages for Commercial	
28	C1	***E+ Commercial Lighting Rebates***	Promote rebates energy efficient lighting in commercial facilities		on-going	x		Commercial and industrial electric customers and the trade allies who serve them	Call to Action--Install high efficiency lighting products	Special Publications (display ads or articles); Case Studies; Lighting trade ally network; Association/Vendor Events; targeted direct mail; business Solutions E-newsletter; solicit features	e-mail to CRMs and key staff	Description of Rebate offers, forms, Lighting Trade Ally lists, case studies; schedule of training events; links to other resources as appropriate	Brochure/Case Studies/Display Signage	
29	C1	***NWE Lighting Trade Ally Network***	Engage Lighting Trade Allies as Partners for program success		on-going	x		Lighting Trade Allies and key facility operators	Call to Action--technical training to improve ability to design, sell, install commercial/industrial energy efficient lighting equipment and to promote NWE Lighting Rebate Program	Qtrly Newsletters, e-mail Direct Mail, web	e-mail to CRMs and key staff	Schedule of training; Registration information; session description; "Qualified" List of Trade Ally Network Members for customers	Training invitation, Program brochure, Newsletter	
30	C2	***E+ Energy Appraisal for Business***	Energy audits for commercial facilities under 300kW with emphasis on electric savings		on-going	x		Electric Commercial facilities under 300 kW	Call to Action--Schedule Appraisal and follow-up on recommendations	Targeted Direct Mail; Energy Connections; Business Solutions E-newsletter; Event Displays;		**Description of offer and contact information**	**Brochure**	
31	C3	***E+ Business Partners***	Promote custom incentives for electric or natural gas cost effective energy efficiency measures in new or existing commercial/industrial facilities		on-going May- Jun & Fall emphasis	x	x	Commercial and industrial electric or natural gas customers and the trade allies who serve them	Call to Action--Install energy saving measures	Special Publications (display ads or articles); Case Studies; trade ally events; Association/Vendor Events; targeted direct mail; Business Solutions E-Newsletter, solicit feature articles		Description of program, application, case studies; Schedule of training events; links to other resources as appropriate	Brochure/Case Studies/Display Signage	

DSM Program Communications Calendar

	A	B	C	D	E	F	G	H	I	J	K	L	M	P
1		DSM Communications Calendar subject to change based upon Need or Opportunity	Campaign/initiative	MO	Implement-ation Dates	E	G	Audience	Message	Media	Internal (includes employees and key contractors)	Web	Hard Materials	Jan
32	C3a	***E+ Business Partners Natural Gas Measures***	Promote commercial natural gas offering custom incentives for new or existing facilities		May- Jun & Fall emphasis		x	Commercial and industrial natural gas customers and the trade allies who serve them	Call to Action--Install energy saving measures; explore offer	Special Publications (display ads or articles); Case Studies as they become available; trade ally events; Association/Vendor Events; targeted direct mail; Business Solutions E-Newsletter		Description of program, application, case studies as become available; Schedule of training events; links to other resources as appropriate	Brochure/Case Studies/Display Signage; presentations	
33	C3b	***E+ Natural Gas Savings Rebates for Commercial Customers -- Existing Buildings***	Promote rebates for qualifying energy efficient equipment and improvements in existing commercial facilities		May-June & Fall emphasis		x	Commercial and industrial natural gas customers and the trade allies who serve them	Call to Action--Install energy saving measures for rebates	Special Publications (display ads or articles); Case Studies as they become available; trade ally events; Association/Vendor Events; targeted direct mail; Business Solutions E-Newsletter, solicit feature articles		Description of program, application, case studies as become available; Schedule of training events; links to other resources as appropriate	Brochure/Case Studies/Display Signage; presentations	
34	C4a	***E+ Natural Gas Savings Rebates for Commercial Customers--New Construction***	Promote rebates for qualifying energy efficient equipment and improvements in new construction commercial facilities		May-June & (Fall?)		x	Commercial and industrial natural gas customers and the trade allies who serve them	Call to Action--Install energy saving measures for rebates	Special Publications (display ads or articles); Case Studies as they become available; trade ally events; Association/Vendor Events; targeted direct mail; Business Solutions E-Newsletter		Description of program, application, case studies as become available; Schedule of training events; links to other resources as appropriate	Brochure/Case Studies/Display Signage presentations	
35	C4b	***E+ Commercial Gas Program***	Engage natural gas Trade Allies as Partners for program success		On-going		x	Commercial and industrial natural gas trade allies and key facility operators	Call to Action--Promote NWE natural gas commercial rebate programs to improve trade allies ability to design, sell, install commercial/industrial qualifying energy efficient natural gas	Multiple site Breakfast/Brown Bag. Direct Mail; e-mail; trade ally newsletters		Schedule of sessions; registration information; preferred contractors as available	Invitation to session; presentation; forms/ applications	

DSM Program Communications Calendar

	A	B	C	D	E	F	G	H	I	J	K	L	M	P
1		DSM Communications Calendar subject to change based upon Need or Opportunity	Campaign/Initiative	MO	Implementation Dates	E	G	Audience	Message	Media	Internal (includes employees and key contractors)	Web	Hard Materials	Jan
36	C5b	***E+ Green Motor Rewind Rebates***	Promote instant rebates for motors rewond to Green Motors Standards in commercial/industrial facilities		as needed	x		Commercial and industrial electric customers with motors and the trade allies who serve them	Call to Action-- Demand GREEN motor standards when having motors rewond	Special Publications (display ads or articles); Case Studies as they become available; trade ally events; Association/Vendor Events; targeted direct mail; Business Solutions E-Newsletter		Description of program, application, case studies as become available; Schedule of training events; links to other resources as appropriate	Brochure/Case Studies/Display Signage; presentations	
37	C5	***Motor Training***	Training/education/ CEU		May (Fall?)	x		Commercial and industrial electric customers with motors and the trade allies who serve them	Education on value of effective motor management techniques; information on NWE programs	Direct Mail; e-mail; trade ally newsletters	e-mail to CSRs, CRMs and key staff	Schedule of training events; course description; registration information	Direct Mail flyer and PDF of same; training manuals	
38	C6	***E+ Irrigation***	Promote custom incentives for cost effective electric irrigation measures		Apr Sept	x		Irrigation customers	Call to Action--submit proposal for custom incentives for cost effective electric irrigation system improvements	Bi-annual mailing to irrigation customers through customer care	e-mail to CSRs, CRMs and key staff	Description of program, application,	Direct mail and include in Business Partner brochure	
39	C9	***Building Operator Certification Training***	Training/education/ certification for facility managers; emphasis on schools, public buildings, non-profit hospitals		Summer maybe Fall as well	x	x	Facility managers with interest in reducing energy costs through operations and maintenance and incorporating energy efficiency in purchases and practices	Call to Action--enroll; scholarships for tuition and travel for public schools, public buildings, and non-profit hospitals	Direct Mail, trade ally newsletters, e-mail, event booths	e-mail to CSRs, CRMs and key staff	Schedule of training events; course description; registration information	Direct Mail flyer and PDF of same; training manuals	
40	C10	***Tri--county Commercial Project***	Promote energy efficiency in existing buildings in partnership with L &C, Broadwater, Jefferson Counties	Mar	3 yr project	x	x	Target small businesses to increase adoption of energy efficiency improvements	Call to Action-- Appraisal, recommendations, standard rebates (Fed. Grants)	Direct contact with targeted businesses			Description for targeted businesses	
41	C11	***E+ Commercial Electric Rebates***	Promote prescriptive rebates for expanded commercial /industrial/irrigation energy efficiency opportunities in existing facilities and new construction			x		Promote opportunities to commercial/industrial/irrigation customers -- Target audiences as appropriate	Call to Action-- install qualifying measures, add to bottom line	Mix	e-mail to CSRs, CRMs and key staff,	Description of program; Add Program contractors; on-line forms; list of events/training;resources	Mix	
42		Renewables												
43	G1	***E+ Renewable Energy***	Support education and development of small scale renewable generation			x		Residential and commercial electric customers and the renewable trade allies who support renewable generation	Educate electric customers on small scale renewables and direct them to resources to develop	Special NWE publications; ltd print ads; energy connections; montanagreenpower.com; trade allies & Associations		Description of program; NWE publications; Schedule of training events; List of events where NWE is present with display or speakers; links to other resources as	NWE publications and Brochures; Signage & presentations	

DSM Program Communications Calendar

	A	B	C	D	E	F	G	H	I	J	K	L	M	P
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	Campaign/Initiative	MO	Implement-ation Dates	E	G	Audience	Message	Media	Internal (includes employees and key contractors)	Web	Hard Materials	Jan
44	G2	***E+ Green Power *****	Offer premium service option of green power product to electric customers		on-going	x		Residential and commercial electric customers who support renewable generation	Call to Action--Opportunity to support renewable generation through premium on electric bill	Energy Connections; Public Radio Sponsorships; other events or sites as appropriate and available		Description of program; on-line enrollment	Brochure; signage	
45														
46	O	***Northwest Energy Efficiency Alliance***	Promote		on-going	x		Residential, Commercial, Industrial, and agriculture customers and the trade allies and infrastructure that serve them	Varies with initiative	NWE supporting materials to NEEA messages	AS APPROPRIATE	Training Information; links to other resources	Varies with initiative	
47														
48		*Large Universal System Benefits Choice (USBC) Customers are not eligible for electric programs. Natural gas commercial programs are not offered to natural gas Choice customers.												
49														
50		**E+ Green is not a DSM program but is part of NWE's renewable offerings.												
51														

DSM Program Communications Calendar

	A	B	Q	R	S	T	U	V	W	X	Y	Z	AA
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2	R0x	**Residential**											
3	R0x	**Tips--Electric (update)**											
4	R0x	**Tips--Natural Gas (update)**											
5	R1x	***Residential Audits***											
6	R1x	Outreach											
7	R1x	Electric Baseload											
8	R2x	***E+ Home Lighting -- CFLs***											
9	R2x	Mail-in Rebate Offer											
10	R2a	Spring Trade Shows a)											
11	R2x	E+ Home Lighting -- CFLs Spring Intant Coupon Offer											
12	R2x	Farmers' Market											

DSM Program Communications Calendar

	A	B	Q	R	S	T	U	V	W	X	Y	Z	AA
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
13	R2a	Fall Trade Shows a)											
14	R2x	Regional Buy downs											
15	R2x	E+ Home Lighting – CFLs Fall Instant Coupon Offer											
16	R3x	***E+ Gas Savings for the Home***											
17	R3x	Gas Savings Mass Media Campaign 1											
18	R3a	Spring Tradeshows a)											
19	R3a	Fall Tradeshows a)											
20	R0x	Special Events--CSR Training, Game Days											
21	R4x	***E+ New Homes***											

DSM Program Communications Calendar

	A	B	Q	R	S	T	U	V	W	X	Y	Z	AA
1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
22	R4x	E+ New Homes Natural Gas											
23	R4x	E+ New Homes Electric											
24	R4x	***E+ Residential Electric Savings***											
25	R6x	**E+ Free Weatherization**											

DSM Program Communications Calendar

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26													
27	C0	**Commercial** *											
28	C1	***E+ Commercial Lighting Rebates***											
29	C1	***NWE Lighting Trade Ally Network***											
30	C2	***E+ Energy Appraisal for Business***											
31	C3	***E+ Business Partners***											

DSM Program Communications Calendar

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1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
32	C3a	***E+ Business Partners Natural Gas Measures***											
33	C3b	***E+ Natural Gas Savings Rebates for Commercial Customers -- Existing Buildings***											
34	C4a	***E+ Natural Gas Savings Rebates for Commercial Customers--New Construction***											
35	C4b	***E+ Commercial Gas Program***											

DSM Program Communications Calendar

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1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
36	C5b	***E+ Green Motor Rewind Rebates***											
37	C5	***Motor Training***											
38	C6	***E+ Irrigation***											
39	C9	***Building Operator Certification Training***											
40	C10	***Tri--county Commercial Project***											
41	C11	***E+ Commercial Electric Rebates***											
42		**Renewables**											
43	G1	***E+ Renewable Energy***											

DSM Program Communications Calendar

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1		**DSM Communications Calendar** subject to change based upon Need or Opportunity	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
44	G2	***E+ Green Power *****											
45													
46	O	***Northwest Energy Efficiency Alliance***											
47													
48		*Large Universal System Benefits Choice (USE											
49		gas commercial programs are not offered to na											
50													
51		**E+ Green is not a DSM program but is part of											

PREFILED DIRECT TESTIMONY

OF FRANK V. BENNETT

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL ELECTRICITY SUPPLY TRACKER

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Witness Information

Q. Please state your name and business address.

A. My name is Frank V. Bennett and my business address is 40 East Broadway, Butte, MT 59701.

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

A. I am employed by NorthWestern Energy ("NorthWestern") as a Contract and Regulatory Specialist.

Q. Please describe your employment history.

A. I have been working with NorthWestern's Supply group since 1996. In this capacity, I administer energy supply contracts for NorthWestern's Montana utility and assist with various other supply matters. I am a regular participant in the preparation of testimony, exhibits, and work papers in supply-related proceedings before the Montana Public Service Commission ("MPSC" or "Commission"). From 1991 through 1996, I worked as a Landman for The Montana Power Company and North American Resources Company. During this time, I worked on Joint Operation contracts with other corporations and with land and mineral owners in an effort to explore and develop natural resources primarily in Montana, Wyoming, and Colorado. From 1984 through 1991, I worked in various capacities within the mineral industry, mainly for Altana Exploration Company and Roan Resources Ltd., in the Canadian provinces of Alberta and Saskatchewan with additional work in Montana and Colorado.

Q. Please describe your educational background.

A. I attended Montana Tech of the University of Montana where I received my Bachelor of Science degree in Business and Information Technology.

Purpose of Testimony

Q. Please describe your Annual Electricity Supply Tracker testimony.

A. In my testimony, I present the following information:

- The tracker exhibits attached to my testimony that are filed in this docket;
- Updates to the costs included in the 12-month ended June 2013 tracker period with 9 months of actual numbers and 3 months of estimated numbers;
- Components included in the 12-month electricity supply cost tracker for the period ended June 2013; and
- The forecast costs of the 12-month ended June 2014 tracker period.

Tracker Presentation in this Docket

Q. Please summarize the tracker presentation filed in this docket.

A. By statutory definition, "Electricity supply costs" means the actual costs incurred in providing electricity supply service through power purchase agreements, demand-side management, and energy efficiency programs…" § 69-8-103(8), MCA. The electric tracker deals only with electricity supply and related costs. I provide testimony and exhibits in this docket separated into four components: (1) Electricity Supply Tracker, (2) Colstrip Unit 4 ("CU4") True-up, (3) Dave Gates Generating Station ("DGGS") True-up, and (4) Spion Kop Wind Generation Asset ("Spion") True-up. All testimony is filed jointly to facilitate a retail customer total supply rate calculation.

Update to the 2012/2013 Electricity Supply Tracker Period

Q. Please summarize the estimated 12-month electricity supply tracker period ending June 2013, as it was filed in Docket No. D2012.5.49.

A. The tracker period ending June 2013 in Docket No. D2012.5.49 included 12 estimated months, July 2012 through June 2013. Interim Order No. 7219 in Docket No. D2012.5.49 authorized rates reflecting the 2012/2013 tracker period estimates effective on July 1, 2012. NorthWestern filed monthly rate adjustments for each month, from August 2012 through June 2013 in Docket No. D2012.7.75.

Q. How has NorthWestern incorporated the CU4 generation that is reflected in the 2012/2013 tracker?

A. NorthWestern has included the full rate-based volume of unit contingent energy associated with 222 megawatts ("MW") of capacity in the tracker.

Q. How has NorthWestern incorporated the DGGS regulation service in the 2012/2013 tracker?

A. The variable costs associated with the provision of regulation service by DGGS, are included in the DGGS True-up. NorthWestern has included 7 MW of energy from DGGS in the tracker to serve retail load.

Q. How has NorthWestern incorporated the Spion generation that is reflected in the 2012/2013 tracker?

A. NorthWestern has included the variable energy volumes generated by Spion's 40 MW of capacity in the tracker. The variable costs associated with Spion are included in the Spion True-up.

Q. How has the regulation cost associated with United Materials of Great Falls ("UMGF") been adjusted in this filing?

A. Consistent with consolidated Docket Nos. D2006.5.66 and D2007.5.46, Final Order No. 6836c, in this tracker filing, NorthWestern reduced regulation costs associated with wind energy contracts that do not serve retail load. Accordingly, NorthWestern removed all associated wind regulation charges for the UMGF project from the 2005/2006 tracker period forward for the periods of time that NorthWestern was not purchasing the output from this facility. The removed regulation charges are not part of the Transmission Business Unit rate NorthWestern charges to its retail customers, but are collected from NorthWestern's equity holders.

Q. In addition to adjustments made for CU4, DGGS, and Spion as described above, how has the 12-month ended June 2013 electricity supply tracker period been updated from the forecasts originally filed in Docket No. D2012.5.49?

A. The 2012 electricity supply tracker filing, Docket No. D2012.5.49, was submitted under cover letter dated May 31, 2012. My prefiled direct testimony in the 2012 filing included information for two tracker periods. Actual and estimated information was submitted for the first tracker period, July 2011 through June 2012. Forecast information was submitted for the second tracker period, July 2012 through June 2013. The first tracker period was updated for 12 months of actual information in response to Data Request PSC-014a in Docket No. D2012.5.49.

The forecast information for the July 2012 through June 2013 period has been updated in this filing with actual information[1] for July 2012 through March 2013, and estimates for April, May, and June of 2013, and is included as Exhibit__(FVB-1)12-13. The actual numbers identify the load, specific monthly resource quantities bought and sold, and related costs for each month in NorthWestern's electricity supply portfolio. Pages 3 and 4

[1] With the exception of transmission (e.g.: load following and imbalance costs) in which there is a lag of actual costs by a number of months.

of Exhibit__(FVB-1)12-13 show that during the 12-month tracker period ending June 2013, NorthWestern expects Total Delivered Supply to be 6,518,048 megawatt hours ("MWh") of electricity. A total of 1,814,128 MWh of this electricity is attributable to our rate-based assets. The remaining 4,703,920 MWh of electricity is projected to be purchased at a cost of $223,454,237 to NorthWestern's electricity supply customers. The July 2012 beginning Deferred Account balance was a $15,312,718 under-collection for the market-based supply portion of this exhibit. Incorporating this under-collection with 9 months of actual and 3 months of estimated information, the 12 months ended June 2013 Deferred Account balance is forecasted to be a $(3,477,111) over-collection (refer to Exhibit__(FVB-1)12-13, page 2). For further discussion of the Deferred Account, please refer to the Prefiled Direct Testimony of Cheryl A. Hansen – Electricity Supply Tracker.

<u>Components of 2012/2013 Electricity Supply Tracker Period</u>

Q. Describe the Electricity Supply cost components of the 12-month ended June 2013 tracker period as shown in Exhibit__(FVB-1)12-13.

A. NorthWestern's tracker exhibits in this filing reflect the expanded data analysis requested by the Commission staff and incorporated for the 2011/2012 tracker period with my testimony in Docket No. D2012.5.49. There are three basic cost components that make up the Electric Supply portfolio for the 12-month tracker period of July 2012 through June 2013:

Electric Supply Expenses, Transmission Costs, and Administrative Expenses.

I. Electric Supply Expenses

A. Off System Transactions – These fixed and indexed price transactions have a delivery point outside of NorthWestern's service territory. Most of these transactions are at the Mid-Columbia trading hub and are used for hedging purposes.

B. On System Transactions – These fixed and indexed price transactions have a delivery point on or within NorthWestern's service territory and include the following:

1. Fixed Price Transactions

   a. Rate-Based Assets – This includes any energy contributed to the Supply Portfolio by NorthWestern's owned generation assets, described below. This energy reduces market purchases that would otherwise be made to balance loads with owned resources.

      i) CU4 is a generation asset approved for inclusion in rates in Docket No. D2008.6.69, Order No. 6925f at the volume of unit contingent energy associated with 222 MW of capacity. This asset was originally included as a rate-based facility in January 2009.

ii) DGGS at Mill Creek is a generation asset approved for inclusion in rates by Order No. 6943e in Docket No. D2008.8.95. NorthWestern includes 7 MW of base load energy as a result of minimum turndown from generating unit operations. This asset was included as a rate-based facility starting January 1, 2011.

iii) Spion is a generation asset approved for inclusion in rates by Order No. 7159l in Docket No. D2011.5.41. NorthWestern includes the variable energy volumes generated by Spion's 40 MW of capacity. This asset was included as a rate-based facility starting December 1, 2012.

b. Base Fixed Price Purchases

i.) A 200 MW peak, 125 MW off-peak contract with PPL Montana, LLC ("PPL") that is supplied seven days per week, 24 hours per day, on a firm basis. This contract expires on June 30, 2014.

ii.) The variable energy generated from the Judith Gap Energy, LLC ("Judith Gap") wind turbine facility with 135 MW of capacity. Judith Gap achieved commercial operation on February 16, 2006. This contract expires on December 31, 2026.

iii.) The energy generated by two hydroelectric power purchase agreements totaling approximately 20 MW of capacity.

iv.) The energy associated with approximately 100 MW of capacity from Qualifying Facility ("QF") contracts entered into prior to 1999. Under Tier II settlements, only a portion of the costs of these contracts is recovered from retail customers through the tracker. The 9-months actual and 3-months estimate shows that these Tier II QFs will meet the 807,609 MWh per year target included in the Stipulation.

v.) The variable energy generated by approximately 46 MW of capacity under various QF supply agreements in two primary groups. The first group includes agreements for approximately 32 MW of capacity that convey renewable energy credits ("RECs") to NorthWestern, which then uses them to meet its renewable energy requirements. The second group includes approximately 14 MW of generation under which the associated RECs remain with the QF (United Materials of Great Falls, plus other small QFs).

vi.) Short- and medium-term market power purchases and sales transacted with various suppliers to balance variable customer demand with electricity supply. The energy requirements vary in part due to customer use and seasonal weather impacts that affect demand.

2. Index Price Transactions

a. Base, short-term, and medium-term market power purchases and sales transacted with various suppliers to balance variable customer demand with electricity supply. The energy requirements vary in part due to customer use and seasonal weather impacts that affect demand.

b. Imbalance charges in three categories, including current month estimates of purchases and sales, prior month true-ups of the earlier estimated values, and accounting and Balancing Authority Area ("BAA") expenses that adjust accounts not tied directly with a specific meter or customer.

C. <u>Ancillary and Other</u> – The following are portfolio supply-related costs that are not actual energy-based power purchase agreements but are required to address the needs of the retail supply portfolio:

1. Approximately 50 MW of dispatchable capacity from Basin Creek Equity Partners, LLC ("Basin Creek"). The Basin Creek plant achieved commercial operation on July 1, 2006. This contract will expire on July 1, 2026, unless extended for a five-year term in accordance with the contract terms.

2. Operating Reserves which are the contingency reserves required to be in place under NorthWestern's BAA transmission tariff. This line item includes the fixed costs of the portion of Basin Creek used to provide operating reserves.

3. Expenses related to "wind other costs" incurred by NorthWestern to fully incorporate wind supply contracts into NorthWestern's energy supply portfolio. These other wind costs include Judith Gap costs, wind modeling, 3TIER services, Fergus Electric service at the met tower site leases, Western Renewable Energy Generation Information System fees, and other direct wind costs.

4. Demand Side Management ("DSM") program implementation costs directly involved with DSM programs and projects and Transmission and Distribution Lost Revenues related to DSM

and Universal System Benefits programs, which are all included as expenses.

II. Transmission Costs

These are costs of network transmission service and those associated with moving electricity off-system via point-to-point transmission service for resource balancing as well as other "ancillary services" required for system integrity and reliability.

Regulation and Frequency Response Service is an ancillary service which provides instantaneous voltage and energy regulation to balance load and resources. Because this service has been provided by the DGGS Generation Asset since January 1, 2011, these costs are now included in the DGGS portion of this filing.

Costs of the transmission facilities utilized to transmit and distribute energy to electric supply customers are included in delivery rates and, as such, no additional revenue is collected for these costs in this tracker filing.

As explained previously, Final Order No. 6836c reduced regulation costs associated with wind energy contracts that do not serve retail load.

III. Administrative Expenses

Incremental administrative and general costs incurred that are in addition to those recovered in the last general rate case filing (Docket No. D2009.9.129) of $1,594,818, or 0.71% of total electric supply expenses are also included in electricity supply costs. These costs include outside legal services, scheduling, software, broker costs, and other incremental expenses directly related to the electricity supply function (such as outside consultants used in conjunction with procurement activities).

Q. Please summarize the results of the 12-month ended June 2013 tracker period.

A. The results of the 2012/2013 tracker period are summarized in the following table:

Beginning Deferred Account		Balance ($)
Under-Collection		$ 15,312,718

Energy Supply/Service	MWh	Cost ($)	$ / MWh
Off System Transactions			
Fixed Price	1,042,462	43,722,602	41.94
Index Price	(1,042,217)	(23,833,009)	22.87
On System Transactions			
Rate-Based Assets	1,814,128		
Base Fixed Price Purchase	3,189,111	145,446,374	45.61
Index Price	1,337,613	26,876,349	20.09
Imbalance	158,012	3,974,110	
Ancillary and Other	18,939	27,267,810	
Transmission Costs	NA	590,060	
Administrative Expenses	NA	1,594,818	
Carrying Cost	NA	279,624	
Total Expenses:		$ 225,918,740	

Electricity Sales	MWh	Revenue ($)
Electric Cost Revenue		$ 232,169,533
Prior Deferred Expense		12,539,036
Total Revenue:		$ 244,708,569

Ending Deferred Account		Balance ($)
Over-Collection		$(3,477,111)

2013/2014 Forecast Electricity Supply Tracker Period

Q. Please summarize the 12-month electricity supply tracker period ending June 2014 as filed in this docket.

A. The June 2013 Deferred Account market-based supply over-collection ending balance of $(3,477,111) as described above is the July 2013 beginning balance. July 2013 through June 2014 information is based on forecast numbers and includes the following existing electric supply contracts: various off-system and on-system fixed and index priced transactions that are comprised of various rate-based assets, QFs, various base purchase contracts, and various term and competitive solicitation contracts. Please see Exhibit__(FVB-2)13-14 pages 3 and 4 for supply volume and cost details of the 12-month forecast tracker period.

Basin Creek plant output in this forecast has been modeled using recent operational experience and expectations of future dispatch based on forward market prices. The actual daily operation of the plant will take into consideration market conditions and the total Electric Supply Portfolio environment.

As explained previously, Final Order No. 6836c reduced regulation costs associated with wind energy contracts that do not serve retail load. NorthWestern removes a portion of regulation costs attributable to the UMGF wind project. This adjustment is reflected in the transmission cost section on page 1 of Exhibit__(FVB-2)13-14.

Q. How has NorthWestern treated regulation costs in the 2013/2014 tracker period?

A. The variable costs associated with the provision of regulation service by DGGS are included in the DGGS section of this filing. NorthWestern has included the 7 MW of DGGS base load energy in the supply portfolio as an energy resource as shown on page 3 of Exhibit__(FVB-2)13-14.

Q. How does the generation output from rate-based generation assets impact the 2013/2014 tracker period?

A. As in the prior tracker period, there are three rate-based generation assets that contribute energy to the electricity supply tracker in this forecast period. They include 222 MW of unit contingent energy associated with CU4, 40 MW of variable energy associated with Spion, and 7 MW of base load energy associated with DGGS.

Q. Describe the Total Supply requirement for the 12-month period ending June 2014 as illustrated in Exhibit__(FVB-2)13-14.

A. NorthWestern's electricity supply forecasted Total Delivered Supply is estimated at 6,491,589 MWh, as shown on page 3 of Exhibit__(FVB-2)13-14.

Q. Please summarize the 12-month ended June 2014 forecast tracker period.

A. The forecast tracker period is summarized in the following table:

Beginning Deferred Account		Balance ($)
Over-Collection		$ (3,477,111)

Energy Supply/Service	MWh	Cost ($)	$ / MWh
Off System Transactions			
Fixed Price	1,217,800	51,393,840	42.20
Index Price	(1,217,800)	(40,910,792)	33.59
On System Transactions			
Rate-Based Assets	1,868,168		
Base Fixed Price Purchases	3,272,070	153,187,709	46.82
Index Price	1,280,212	45,777,863	35.76
Imbalance	0	0	
Ancillary and Other	71,139	28,113,579	
Transmission Costs	NA	794,096	
Administrative Expenses	NA	1,581,448	
Carrying Cost	NA	(243,201)	
Total Expenses:		239,694,540	

Electricity Sales	MWh	Revenue ($)
Electric Cost Revenue		$239,694,540
Prior Deferred Expense		(3,477,111)
Total Revenue:		$236,217,429

Ending Deferred Account		Balance ($)
Even Collection		$ 0

Q. Describe the electric supply Revenue and Expense categories for the 12-month ended June 2014 forecast tracker period.

A. The electricity supply tracker revenue and expense details are reflected on page 1 of Exhibit__(FVB-2)13-14 under two main sections, Total Revenue and Total Expenses. Total Revenue is estimated to be $236,217,429. This includes the $(3,477,111) over-collection for the 2012-2013 tracker period. The 12-month forecast tracker period estimates the Total

Expenses as $239,694,540, reflecting an increase from the prior period. The costs shown above reflected in the forecast period include DSM costs and lost T&D revenues that are further explained in the Prefiled Direct Testimony of William M. Thomas.

Q. Are there any additional updates anticipated for the first month of this tracker rate filing?

A. No, not at this time. Because a regular monthly filing would have been submitted on June 15, 2013, for July 2013 rates, this tracker reflects the first monthly tracker rate filing under a yet-to-be-assigned monthly tracker docket number. The electric market forecast used in this filing was dated several weeks earlier than the forecasts normally used in monthly tracker rate filings. Therefore, if electric market prices decrease or increase dramatically prior to June 15, 2013, NorthWestern will file a monthly tracker rate filing update for a July 2013 rate adjustment.

Q. Does this conclude your Annual Electricity Supply Tracker testimony?

A. Yes, it does.

	A B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Electric Supply Cost Tracker**													
2	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
3														
4		**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Total**
5		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	
6	Total Sales and Unit Costs													
7	MWh	508,737	551,049	516,614	445,633	451,251	507,415	565,008	522,733	487,459	461,420	453,754	497,067	5,968,140
8	Supply Cost	$ 39.1902	$ 38.1487	$ 38.7757	$ 38.7570	$ 39.1902	$ 38.9468	$ 38.9932	$ 38.4429	$ 39.1080	$ 39.0577	$ 38.9658	$ 38.9658	$ 39.1902
9	YNP MWh	3,924	1,502	2,621	2,162	1,481	671	555	532	568	553	2,402	2,588	19,558
10	YNP Supply Rate	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000
11	Prior Year(s) Deferred Expense	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	
12														
13														
14	Electric Cost Revenues													
15	NWE Electric Supply	$ 19,077,519	$ 21,086,958	$ 19,785,214	$ 17,255,477	$ 17,557,654	$ 19,866,465	$ 22,095,107	$ 20,294,221	$ 18,880,319	$ 18,047,326	$ 17,680,909	$ 19,368,627	$ 230,995,797
16	YNP Electric Supply	$ 235,417	$ 90,103	$ 157,269	$ 129,707	$ 89,185	$ 40,534	$ 33,304	$ 31,922	$ 33,888	$ 33,017	$ 144,100	$ 155,290	$ 1,173,736
17	Subtotal	$ 19,312,937	$ 21,177,061	$ 19,942,483	$ 17,385,184	$ 17,646,839	$ 19,906,999	$ 22,128,411	$ 20,326,143	$ 18,914,207	$ 18,080,343	$ 17,825,009	$ 19,523,917	$ 232,169,533
18	Prior Year(s) Deferred Expense	$ 1,911,087	$ 383,254	$ 1,092,388	$ 946,625	$ 961,494	$ 1,078,367	$ 1,200,713	$ 1,110,621	$ 1,035,866	$ 980,617	$ 877,138	$ 960,865	$ 12,539,036
19	Total Revenue	$ 21,224,024	$ 21,560,314	$ 21,034,872	$ 18,331,809	$ 18,608,333	$ 20,985,366	$ 23,329,124	$ 21,436,764	$ 19,950,073	$ 19,060,960	$ 18,702,148	$ 20,484,782	$ 244,708,569
20														
21	Electric Supply Expenses													
22	Net Base Purchases	$ 12,803,996	$ 13,853,532	$ 13,308,976	$ 14,348,111	$ 13,869,570	$ 14,308,324	$ 18,135,782	$ 16,750,733	$ 17,272,347	$ 17,916,024	$ 18,227,003	$ 17,278,392	$ 188,072,790
23	Net Base Sales	$ (278,580)	$ (390,724)	$ (300,788)	$ (411,288)	$ (343,035)	$ (317,880)	$ (356,968)	$ (327,158)	$ (394,345)	$ (781,000)	$ (677,730)	$ (583,240)	$ (5,162,736)
24	Net Term Purchases	$ 4,175,907	$ 4,279,656	$ 1,536,552	$ 1,250,316	$ 1,317,860	$ 2,717,212	$ 980,805	$ 911,035	$ 813,080	$ 257,400	$ 214,448	$ 180,800	$ 18,635,072
25	Net Term Sales	$ (2,314,541)	$ (213,113)	$ (652,977)	$ (161,431)	$ -	$ -	$ -	$ -	$ (2,349,150)	$ (1,980,000)	$ (1,738,728)	$ (1,499,760)	$ (10,909,700)
26	Net Spot Purchases	$ 1,501,518	$ 1,427,581	$ 547,903	$ 881,806	$ 1,164,280	$ 1,390,939	$ (886,607)	$ 802,450	$ 1,076,168	$ (37,409)	$ 939,841	$ 1,743,077	$ 10,551,546
27	Net Spot Sales	$ (30,952)	$ (2,490,462)	$ (127,366)	$ (958,129)	$ (859,983)	$ (1,193,266)	$ (297,088)	$ (2,365,513)	$ (563,668)	$ (26,163)	$ (20,977)	$ (41,088)	$ (8,974,655)
28	Other Tracker Costs	$ 2,787,893	$ 4,092,350	$ 2,042,396	$ 2,303,391	$ 3,544,794	$ 2,526,286	$ 2,396,420	$ 1,562,877	$ 1,859,531	$ 2,462,426	$ 3,618,152	$ 2,045,404	$ 31,241,920
29	Total Electric Supply Expenses	$ 18,645,240	$ 20,558,820	$ 16,354,695	$ 17,252,776	$ 18,693,487	$ 19,431,615	$ 19,972,344	$ 17,334,425	$ 17,713,964	$ 17,811,278	$ 20,562,007	$ 19,123,585	$ 223,454,237
30														
31	NWE Transmission Costs													
32														
33	Other Services (Wheeling)	$ 47,679	$ 53,042	$ 50,455	$ 81,375	$ 80,868	$ 88,725	$ 90,264	$ 134,174	$ 116,442	$ 14,698	$ 18,006	$ 33,832	$ 809,559
34	Ancillary Cost (Disallowed)	$ (13,781)	$ (47,093)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (219,499)
35	Total NWE Transmission	$ 33,898	$ 5,949	$ 34,592	$ 65,513	$ 65,006	$ 72,862	$ 74,401	$ 118,312	$ 100,580	$ (1,165)	$ 2,144	$ 17,969	$ 590,060
36														
37	Administrative Expenses													
38	MPSC Tax Collection	$ 41,570	$ 42,712	$ 41,533	$ 41,636	$ 42,512	$ 47,532	$ 53,057	$ 49,147	$ 44,926	$ 12,304	$ 12,478	$ 13,667	$ 443,073
39	MCC Tax Collection	$ 24,942	$ 25,627	$ 24,920	$ 12,672	$ 12,938	$ 14,466	$ 16,148	$ 14,958	$ 13,673	$ 40,427	$ 40,998	$ 44,905	$ 286,674
40	Modeling	$ 76,190	$ 54,671	$ 52,379	$ 88,046	$ 25,830	$ 12,175	$ 38,480	$ 40,292	$ 39,355	$ 20,198	$ 20,198	$ 20,198	$ 488,010
41	Trading & Marketing	$ 9,927	$ 7,774	$ 6,325	$ 8,782	$ 8,121	$ 7,424	$ 7,184	$ 7,184	$ 7,981	$ 8,327	$ 8,327	$ 8,327	$ 95,683
42	Administration	$ 38,027	$ 8,900	$ 4,400	$ 4,400	$ 4,400	$ 67,618	$ 4,428	$ 5,259	$ 99,871	$ 14,692	$ 14,692	$ 14,692	$ 281,379
43	Total Administrative Expenses	$ 190,657	$ 139,684	$ 129,556	$ 155,535	$ 93,801	$ 149,215	$ 119,296	$ 116,840	$ 205,806	$ 95,948	$ 96,692	$ 101,789	$ 1,594,818
44														
45	Carrying Cost Expense													
46	Carrying Costs	$ 86,042	$ 80,930	$ 51,482	$ 46,127	$ 48,053	$ 39,530	$ 18,791	$ (6,762)	$ (19,620)	$ (27,419)	$ (14,595)	$ (22,935)	$ 279,624
47	Total Carrying Costs	$ 86,042	$ 80,930	$ 51,482	$ 46,127	$ 48,053	$ 39,530	$ 18,791	$ (6,762)	$ (19,620)	$ (27,419)	$ (14,595)	$ (22,935)	$ 279,624
48														
49														
50	Total Expenses	$ 18,955,837	$ 20,785,383	$ 16,570,326	$ 17,519,951	$ 18,900,346	$ 19,693,223	$ 20,184,832	$ 17,562,815	$ 18,000,730	$ 17,878,643	$ 20,646,248	$ 19,220,408	$ 225,918,740
51														
52	Deferred Cost Amortization	$ 1,911,087	$ 383,254	$ 1,092,388	$ 946,625	$ 961,494	$ 1,078,367	$ 1,200,713	$ 1,110,621	$ 1,035,866	$ 980,617	$ 877,138	$ 960,865	$ 12,539,036
53	(under collection)/over collection													
54	Monthly Deferred Cost	$ 357,100	$ 391,678	$ 3,372,158	$ (134,767)	$ (1,253,507)	$ 213,777	$ 1,943,579	$ 2,763,328	$ 913,477	$ 201,700	$ (2,821,239)	$ 303,509	$ 6,250,793
55	Cumulative Deferred Cost	$ 357,100	$ 748,778	$ 4,120,936	$ 3,986,169	$ 2,732,661	$ 2,946,438	$ 4,890,017	$ 7,653,345	$ 8,566,822	$ 8,768,523	$ 5,947,284	$ 6,250,793	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	**Electric Supply Cost Tracker**													
2	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
3														
4														
5			**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**
6			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate
7														
8			Note: for supply cost expense positive value reflects an under collection, negative an (over collection).											
9	Deferred Supply Cost Expense													
10		Beginning Balance	$ **15,312,718**	$ 13,044,530	$ 12,269,599	$ 7,805,053	$ 6,993,195	$ 7,285,208	$ 5,993,064	$ 2,848,772	$ (1,025,177)	$ (2,974,520)	$ (4,156,837)	$ (2,212,737)
11		Monthly Deferred Cost	$ (2,268,187)	$ (774,932)	$ (4,464,546)	$ (811,858)	$ 292,013	$ (1,292,143)	$ (3,144,292)	$ (3,873,949)	$ (1,949,343)	$ (1,182,318)	$ 1,944,100	$ (1,264,374)
12		Ending Balance	$ 13,044,530	$ 12,269,599	$ 7,805,053	$ 6,993,195	$ 7,285,208	$ 5,993,064	$ 2,848,772	$ (1,025,177)	$ (2,974,520)	$ (4,156,837)	$ (2,212,737)	$ (3,477,111)
13														
14														
15	Total Capital		$ 13,044,530	$ 12,269,599	$ 7,805,053	$ 6,993,195	$ 7,285,208	$ 5,993,064	$ 2,848,772	$ (1,025,177)	$ (2,974,520)	$ (4,156,837)	$ (2,212,737)	$ (3,477,111)
16														
17														
18														
19	Cost of Capital		Rate	% Capitalization	Rate of Return									
20		Long-Term Debt	5.76%	52.00%	3.00%									
21		Common Equity	10.25%	48.00%	4.92%									
22														
23		Average Cost of Capital			7.92%									
24														
25	Deferred Supply Expense													
26		Carrying Charge	7.92%											
27														

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Electric Supply Cost Tracker**														
2	**Electric Tracker Projection**														
3															
4	**Volumes in MWh**		**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Total**
5			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	
6	**Off System Transactions**														
7	**Fixed Price**														
8	Base Fixed Price Purchases		-	-	-	-	-	-	-	-	-	-	-	-	-
9	Competitive Solicitations		28,600	29,400	27,600	29,400	28,025	28,600	103,400	93,598	103,275	100,400	100,400	103,400	776,098
10	Base Fixed Price Sales		-	-	-										-
11	Competitive Solicitations		-	-	-	-	-	-			-	-	-	-	-
12	Term Fixed Price Purchases		90,000	75,564	19,200	21,600	20,000	40,000	-	-	-	-	-	-	266,364
13	Term Fixed Price Sales		-	-	-	-	-	-			-	-	-	-	-
14	**Index Price**														
15	Base Index Price Purchases		-	-	-	-	-	-			-	-	-	-	-
16	Base Index Price Sales			-	-	-	-	-			-	-			-
17	Competitive Solicitations		(28,600)	(29,400)	(27,600)	(29,515)	(28,025)	(28,600)	(29,000)	(26,402)	(28,975)	(28,400)	(28,400)	(29,000)	(341,917)
18	Term Index Price Purchases		-	-	-	-	-	-			-	-	-	-	-
19	Term Index Price Sales		(90,000)	(75,600)	-	-	-	-			(74,300)	(72,000)	(72,000)	(74,400)	(458,300)
20	Spot Purchases		400		-	-	-	-			-	-	-	-	400
21	Spot Sales		-	-	(19,200)	(21,600)	(20,000)	(40,000)	(74,400)	(67,200)	-	-	-	-	(242,400)
22															
23	**On System Transactions**														
24	**Fixed Price**														
25	Rate-Based Assets														
26	Colstrip Unit 4		89,669	149,166	148,514	150,045	152,348	138,213	159,562	143,944	151,263	146,160	99,876	90,132	1,618,892
27	Dave Gates Generating Station		5,208	5,208	5,040	5,208	5,047	5,208	5,208	29,580	5,201	5,040	5,208	5,040	86,196
28	Spion Kop		-	-	-	-	15,216	15,967	18,619	17,979	12,171	11,520	8,928	8,640	109,040
29	Base Fixed Price Purchases														
30	PPL 7 Year Contract		124,200	125,400	118,800	125,400	120,125	123,000	124,200	112,800	124,075	121,200	124,200	120,000	1,463,400
31	Judith Gap		21,604	26,452	28,382	40,055	43,758	48,594	67,086	57,104	42,072	39,803	35,962	26,626	477,498
32	Other Non-QF		14,334	11,321	8,600	5,524	3,933	11,769	3,921	11,832	3,863	12,960	13,392	12,960	114,409
33	Competitive Solicitations		20,000	21,600	19,200	21,600	20,000	20,000	20,800	19,200	20,800	20,800	20,800	20,000	244,800
34	QF Tier II		51,659	65,484	71,306	77,783	72,898	75,106	74,544	65,138	75,784	68,123	74,697	75,155	847,677
35	QF Tier II Adjustments		(6,001)												(6,001)
36	QF-1 Tariff Contracts		3,518	3,402	2,938	4,379	5,401	5,540	6,315	5,280	4,966	7,560	8,160	6,840	64,299
37	Term Fixed Price Purchases		2,158	1,350	1,200	1,350	1,971	1,250	1,950	1,800	1,950	1,950	1,950	1,875	20,754
38	Term Fixed Price Sales		(6,458)	(6,558)	(5,312)	(5,472)	(1,200)	(1,250)	(1,950)	(1,800)	(1,950)	(1,950)	(1,950)	(1,875)	(37,725)
39	**Index Price**														
40	Base Index Price Purchases														
41	Competitive Solicitations		28,600	29,400	27,600	29,400	28,025	28,600	45,400	40,800	45,325	43,600	45,400	44,000	436,150
42	Term Index Price Purchases		79,333	73,709	36,000	18,473	19,566	50,572	34,149	31,277	23,792	10,400	10,400	10,000	397,671
43	Term Index Price Sales		-	-	-	-	-	-	-	-	-	-	-	-	-
44	Spot Purchases		161,548	69,656	24,849	30,159	42,873	66,174	40,619	30,231	31,593	(1,363)	40,633	79,051	616,023
45	Spot Sales		(2,861)	(7,524)	(6,447)	(10,886)	(12,461)	(6,488)	(12,419)	(20,176)	(24,466)	(1,204)	(1,914)	(5,385)	(112,231)
46	Imbalance, Current Month Estimate		41,876	11,831	7,153	7,145	12,115	-	17,703	3,591	-	-	-	-	101,414
47	Imbalance, Prior Months True-up		(4,324)	(30,248)	41,876	-	11,901	-	27,548	27,548	(17,703)	-	-	-	56,598
48	Imbalance, Accounting & BA Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
49															
50	**Ancillary and Other**														
51	Basin Creek Fixed Costs		-	-	-	-	-	-	-	-	-	-	-	-	-
52	Basin Creek Variable Costs		2,236	-	1,175	-	-	4,584	3,863	1,261	4,215	772	571	262	18,939
53	Basin Creek Fuel														
54	Basin Creek Storage														
55	Operating Reserves		-	-	-	-	-	-	-	-	-	-	-	-	-
56	Wind Other Cost														
57	DSM Program & Labor Costs		-	-	-	-	-	-	-	-	-	-	-	-	-
58	DSM Lost T& D Revenues		-	-	-	-	-	-	-	-	-	-	-	-	-
59	DSM Lost Revenue Adjustment														
60															
61	**Total Delivered Supply**		626,699	549,613	530,873	500,048	541,516	586,840	637,119	577,385	502,951	485,372	486,313	493,321	6,518,048
62															
63	**Electric Tracker Projection Excluding Generation Assets Cost of Service**														
64	**Total Supply Expense**														
65															

	A B	C	D	E	F	G	H	I	J	K	L	M	N	O
66	**Energy Supply Revenue (Expense)**	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Total
67		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	
68	**Off System Transactions**													
69	**Fixed Price**													
70	Base Fixed Price Purchases													
71	Competitive Solicitations	$ 1,652,140	$ 1,691,460	$ 1,595,040	$ 1,691,460	$ 1,616,260	$ 1,652,140	$ 4,362,240	$ 3,958,958	$ 4,357,660	$ 4,252,320	$ 4,362,240	$ 4,215,600	$ 35,407,518
72	Base Fixed Price Sales													
73	Competitive Solicitations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	Term Fixed Price Purchases	$ 2,488,500	$ 2,203,344	$ 689,760	$ 775,980	$ 718,500	$ 1,439,000		$ -		$ -	$ -	$ -	$ 8,315,084
75	Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
76	**Index Price**													
77	Base Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
78	Base Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -			$ -
79	Competitive Solicitations	$ (278,580)	$ (390,724)	$ (300,788)	$ (411,288)	$ (343,035)	$ (317,880)	$ (356,968)	$ (327,158)	$ (394,345)	$ (781,000)	$ (677,730)	$ (583,240)	$ (5,162,736)
80	Term Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81	Term Index Price Sales	$ (1,996,020)	$ -	$ (492,616)	$ -	$ -	$ -	$ -	$ -	$ (2,349,150)	$ (1,980,000)	$ (1,738,728)	$ (1,499,760)	$ (10,056,274)
82	Spot Purchases	$ 14,100	$ -	$ -	$ -	$ -	$ -	$ (2,046,704)	$ -	$ -	$ -	$ -	$ -	$ (2,032,604)
83	Spot Sales	$ -	$ (2,339,392)	$ -	$ (701,256)	$ (577,920)	$ (1,047,820)	$ -	$ (1,915,008)	$ -	$ -	$ -	$ -	$ (6,581,396)
84														
85	**On System Transactions**													
86	**Fixed Price**													
87	Rate-Based Assets													
88	Colstrip Unit 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89	Dave Gates Generating Station	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	Spion Kop	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	Base Fixed Price Purchases													
92	PPL 7 Year Contract	$ 6,532,920	$ 6,596,040	$ 6,248,880	$ 6,602,310	$ 6,324,581	$ 6,475,950	$ 6,545,340	$ 5,944,560	$ 6,538,753	$ 6,393,300	$ 6,551,550	$ 6,330,000	$ 77,084,184
93	Judith Gap	$ 645,025	$ 900,168	$ 968,872	$ 1,205,418	$ 1,399,531	$ 1,597,468	$ 2,186,368	$ 1,861,475	$ 1,272,812	$ 1,263,750	$ 1,141,788	$ 845,372	$ 15,288,046
94	Other Non-QF	$ 796,609	$ 601,173	$ 433,511	$ 219,619	$ 160,166	$ 160,166	$ 160,166	$ 632,668	$ 160,166	$ 754,920	$ 780,084	$ 754,920	$ 5,614,168
95	Competitive Solicitations	$ 1,080,500	$ 1,166,940	$ 1,037,280	$ 1,166,940	$ 1,080,500	$ 1,080,500	$ 1,123,720	$ 1,037,280	$ 1,123,720	$ 1,123,720	$ 1,123,720	$ 1,080,500	$ 13,225,320
96	QF Tier II	$ 1,820,403	$ 2,401,298	$ 2,614,791	$ 2,852,303	$ 2,673,170	$ 2,754,137	$ 2,733,528	$ 2,388,610	$ 2,778,999	$ 2,498,070	$ 2,739,139	$ 2,755,934	$ 31,010,383
97	QF Tier II Adjustments	$ (102,929)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (102,929)
98	QF-1 Tariff Contracts	$ 176,549	$ 183,130	$ 183,013	$ 280,493	$ 346,402	$ 345,883	$ 400,936	$ 333,981	$ 302,745	$ 523,944	$ 566,184	$ 475,546	$ 4,118,805
99	Term Fixed Price Purchases	$ 49,613	$ -	$ -	$ -	$ 12,210	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 61,823
100	Term Fixed Price Sales	$ (318,521)	$ (213,113)	$ (160,361)	$ (161,431)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (853,426)
101	**Index Price**													
102	Base Index Price Purchases													
103	Competitive Solicitations	$ 202,780	$ 313,324	$ 227,588	$ 329,568	$ 268,960	$ 242,080	$ 623,484	$ 593,200	$ 737,492	$ 1,106,000	$ 962,298	$ 820,520	$ 6,427,294
104	Term Index Price Purchases	$ 1,637,793	$ 2,076,312	$ 846,792	$ 474,336	$ 587,150	$ 1,278,212	$ 980,805	$ 911,035	$ 813,080	$ 257,400	$ 214,448	$ 180,800	$ 10,258,164
105	Term Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
106	Spot Purchases	$ 1,487,418	$ 1,427,581	$ 547,903	$ 881,806	$ 1,164,280	$ 1,390,939	$ 1,160,097	$ 802,450	$ 1,076,168	$ (37,409)	$ 939,841	$ 1,743,077	$ 12,584,150
107	Spot Sales	$ (30,952)	$ (151,070)	$ (127,366)	$ (256,873)	$ (282,063)	$ (145,446)	$ (297,088)	$ (450,505)	$ (563,668)	$ (26,163)	$ (20,977)	$ (41,088)	$ (2,393,259)
108	Imbalance, Current Month Estimate	$ 399,560	$ 193,149	$ 105,034	$ 154,795	$ 242,355	$ 736,503	$ 399,525	$ 75,251	$ 39,937	$ -	$ -	$ -	$ 2,346,109
109	Imbalance, Prior Months True-up	$ (7,046)	$ (9,973)	$ (43,697)	$ 135,151	$ 93,255	$ (154,795)	$ 186,406	$ 10,391	$ (136,485)	$ -	$ -	$ -	$ 73,207
110	Imbalance, Accounting & BA Expense	$ 875,495	$ 458,459	$ 43,697	$ 89,215	$ (168,855)	$ 154,795	$ -	$ (151,788)	$ 253,777	$ -	$ -	$ -	$ 1,554,794
111														
112	**Ancillary and Other**													
113	Basin Creek Fixed Costs	$ 452,985	$ 452,985	$ 452,985	$ 452,985	$ 878,354	$ 452,985	$ 412,077	$ 460,191	$ 460,191	$ 354,408	$ 926,037	$ 354,408	$ 6,110,591
114	Basin Creek Variable Costs	$ 10,883	$ 19,638	$ 5,668	$ 13,455	$ 2,955	$ 21,343	$ 18,083	$ 6,010	$ 19,533	$ 27,218	$ 20,331	$ 9,286	$ 174,402
115	Basin Creek Fuel	$ 73,669	$ 93,036	$ 47,924	$ 87,122	$ 40,935	$ 166,984	$ 152,305	$ 69,993	$ 160,109				$ 892,078
116	Basin Creek Storage	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 36,000
117	Operating Reserves	$ 104,160	$ 104,160	$ 100,800	$ 104,160	$ 100,940	$ 111,600	$ 111,600	$ 100,800	$ 111,450	$ 201,600	$ 208,320	$ 201,600	$ 1,561,190
118	Wind Other Cost	$ 24,523	$ 2,873	$ 5,476	$ 18,177	$ 767,871	$ 2,871	$ 6,955	$ 26,728	$ 4,445	$ 12,360	$ 701,803	$ 12,360	$ 1,586,440
119	DSM Program & Labor Costs	$ 455,133	$ 2,379,492	$ 925,980	$ 849,801	$ 1,188,455	$ 635,469	$ 710,938	$ 566,772	$ 548,044	$ 1,468,309	$ 1,102,118	$ 1,069,220	$ 11,899,730
120	DSM Lost T& D Revenues	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 4,746,366
121	DSM Lost Revenue Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 261,013	$ -	$ 261,013
122														
123	**Total Delivered Supply**	$ 18,645,240	$ 20,558,820	$ 16,354,695	$ 17,252,776	$ 18,693,487	$ 19,431,615	$ 19,972,344	$ 17,334,425	$ 17,713,964	$ 17,811,278	$ 20,562,007	$ 19,123,585	$ 223,454,237
124		Wind Other Cost includes: Judith Gap impact fees and property tax charges, Global Energy fees, 3 Tier fees, electric service at met towers, and met tower site leases.												
125	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
126	**Unit Costs**													
127														

	A B	C	D	E	F	G	H	I	J	K	L	M	N	O
128	**Energy Supply Unit Costs**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Total**
129		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	
130	**Off System Transactions**													
131	**Fixed Price**													
132	Base Fixed Price Purchases													
133	Competitive Solicitations	$ 57.77	$ 57.53	$ 57.79	$ 57.53	$ 57.67	$ 57.77	$ 42.19	$ 42.30	$ 42.19	$ 42.35	$ 43.45	$ 40.77	$ 45.62
134	Base Fixed Price Sales													
135	Competitive Solicitations	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
136	Term Fixed Price Purchases	$ 27.65	$ 29.16	$ 35.93	$ 35.93	$ 35.93	$ 35.98	n/a	n/a	n/a	n/a	n/a	n/a	$ 31.22
137	Term Fixed Price Sales	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
138	**Index Price**													
139	Base Index Price Purchases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140	Base Index Price Sales													
141	Competitive Solicitations	$ 9.74	$ 13.29	$ 10.90	$ 13.93	$ 12.24	$ 11.11	$ 12.31	$ 12.39	$ 13.61	$ 27.50	$ 23.86	$ 20.11	$ 15.10
142	Term Index Price Purchases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
143	Term Index Price Sales	$ 22.18	$ -	n/a	n/a	n/a	n/a	n/a	n/a	$ 31.62	$ 27.50	$ 24.15	$ 20.16	$ 21.94
144	Spot Purchases	$ 35.25	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	$ (5,081.51)
145	Spot Sales	n/a	n/a	$ -	$ 32.47	$ 28.90	$ 26.20	$ -	$ 28.50	n/a	n/a	n/a	n/a	$ 27.15
146														
147	**On System Transactions**													
148	**Fixed Price**													
149	Rate-Based Assets													
150	Colstrip Unit 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
151	Dave Gates Generating Station	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
152	Spion Kop	n/a	n/a	n/a	n/a	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
153	Base Fixed Price Purchases													
154	PPL 7 Year Contract	$ 52.60	$ 52.60	$ 52.60	$ 52.65	$ 52.65	$ 52.65	$ 52.70	$ 52.70	$ 52.70	$ 52.75	$ 52.75	$ 52.75	$ 52.67
155	Judith Gap	$ 29.86	$ 34.03	$ 34.14	$ 30.09	$ 31.98	$ 32.87	$ 32.59	$ 32.60	$ 30.25	$ 31.75	$ 31.75	$ 31.75	$ 32.02
156	Other Non-QF	$ 55.57	$ 53.10	$ 50.41	$ 39.76	$ 40.72	$ 13.61	$ 40.85	$ 53.47	$ 41.46	$ 58.25	$ 58.25	$ 58.25	$ 49.07
157	Competitive Solicitations	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03
158	QF Tier II	$ 35.24	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.58
159	QF Tier II Adjustments													
160	QF-1 Tariff Contracts	$ 50.18	$ 53.83	$ 62.30	$ 64.05	$ 64.13	$ 62.43	$ 63.49	$ 63.25	$ 60.96	$ 69.30	$ 69.39	$ 69.52	$ 64.06
161	Term Fixed Price Purchases	$ 22.99	$ -	$ -	$ -	$ 6.19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.98
162	Term Fixed Price Sales	$ 49.32	$ 32.50	$ 30.19	$ 29.50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22.62
163	**Index Price**													
164	Base Index Price Purchases													
165	Competitive Solicitations	$ 7.09	$ 10.66	$ 8.25	$ 11.21	$ 9.60	$ 8.46	$ 13.73	$ 14.54	$ 16.27	$ 25.37	$ 21.20	$ 18.65	$ 14.74
166	Term Index Price Purchases	$ 20.64	$ 28.17	$ 23.52	$ 25.68	$ 30.01	$ 25.28	$ 28.72	$ 29.13	$ 34.17	$ 24.75	$ 20.62	$ 18.08	$ 25.80
167	Term Index Price Sales	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
168	Spot Purchases	$ 9.21	$ 20.49	$ 22.05	$ 29.24	$ 27.16	$ 21.02	$ 28.56	$ 26.54	$ 34.06	$ 27.45	$ 23.13	$ 22.05	$ 20.43
169	Spot Sales	$ 10.82	$ 20.08	$ 19.76	$ 23.60	$ 22.64	$ 22.42	$ 23.92	$ 22.33	$ 23.04	$ 21.73	$ 10.96	$ 7.63	$ 21.32
170	Imbalance, Current Month Estimate	$ 9.54	$ 16.33	$ 14.68	$ 21.66	$ 20.00	n/a	$ 22.57	$ 20.96	n/a	n/a	n/a	n/a	$ 23.13
171	Imbalance, Prior Months True-up	$ 1.63	$ 0.33	$ (1.04)	n/a	$ 7.84	n/a	$ 6.77	$ 0.38	$ 7.71	n/a	n/a	n/a	$ 1.29
172	Imbalance, Accounting & BA Expense													
173														
174	**Ancillary and Other**													
175	Basin Creek Fixed Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
176	Basin Creek Variable Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
177	Basin Creek Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
178	Basin Creek Storage	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
179	Operating Reserves	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
180	Wind Other Cost	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
181	DSM Program & Labor Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
182	DSM Lost T& D Revenues	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
183	DSM Lost Revenue Adjustment	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
184														
185														
186	**Total Delivered Supply**	$ 29.75	$ 37.41	$ 30.81	$ 34.50	$ 34.52	$ 33.11	$ 31.35	$ 30.02	$ 35.22	$ 36.70	$ 42.28	$ 38.77	$ 34.28
187														

	A B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Electric Supply Cost Tracker**													
2	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
3														
4		**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Total**
5		Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
6	Total Sales and Unit Costs													
7	MWh	510,194	533,603	488,645	465,210	483,078	530,062	563,388	525,942	497,190	474,079	453,460	462,147	5,986,998
8	Supply Cost	$ 39.8325	$ 39.8325	$ 39.8325	$ 39.8325	$ 39.8325	$ 39.8325	$ 39.8325	$ 39.8325	$ 39.8325	$ 39.8325	$ 39.8325	$ 39.8325	$ 39.8325
9	YNP MWh	2,529	2,560	2,294	1,436	905	916	1,038	967	878	1,150	2,320	2,241	19,234
10	YNP Supply Rate	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000
11	Prior Year(s) Deferred Expense	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	
12														
13														
14	Electric Cost Revenues													
15	NWE Electric Supply	$ 20,322,278	$ 21,254,739	$ 19,463,966	$ 18,530,469	$ 19,242,180	$ 21,113,676	$ 22,441,130	$ 20,949,598	$ 19,804,323	$ 18,883,754	$ 18,062,460	$ 18,408,458	$ 238,477,031
16	YNP Electric Supply	$ 160,110	$ 162,044	$ 145,199	$ 90,901	$ 57,287	$ 58,013	$ 65,719	$ 61,183	$ 55,598	$ 72,786	$ 146,844	$ 141,826	$ 1,217,509
17	Subtotal	$ 20,482,387	$ 21,416,783	$ 19,609,165	$ 18,621,370	$ 19,299,467	$ 21,171,689	$ 22,506,849	$ 21,010,781	$ 19,859,921	$ 18,956,540	$ 18,209,304	$ 18,550,285	$ 239,694,540
18	Prior Year(s) Deferred Expense	$ (296,309)	$ (309,904)	$ (283,794)	$ (270,183)	$ (280,560)	$ (307,848)	$ (327,203)	$ (305,455)	$ (288,757)	$ (275,334)	$ (263,359)	$ (268,404)	$ (3,477,111)
19	Total Revenue	$ 20,186,079	$ 21,106,878	$ 19,325,370	$ 18,351,187	$ 19,018,907	$ 20,863,841	$ 22,179,646	$ 20,705,325	$ 19,571,164	$ 18,681,206	$ 17,945,945	$ 18,281,880	$ 236,217,429
20														
21	Electric Supply Expenses													
22	Net Base Purchases	$ 17,562,666	$ 17,389,500	$ 17,617,398	$ 19,025,699	$ 18,593,444	$ 19,377,170	$ 20,111,280	$ 17,698,540	$ 19,298,949	$ 17,896,210	$ 18,498,754	$ 17,608,201	$ 220,677,811
23	Net Base Sales	$ (1,100,200)	$ (1,302,162)	$ (1,085,220)	$ (1,064,424)	$ (1,030,547)	$ (1,138,740)	$ (1,097,468)	$ (958,656)	$ (996,192)	$ (637,004)	$ (734,742)	$ (682,160)	$ (11,827,515)
24	Net Term Purchases	$ 2,490,800	$ 2,453,220	$ 371,520	$ 375,840	$ 876,751	$ 1,750,509	$ 768,144	$ 677,376	$ 343,928	$ 239,096	$ 276,328	$ -	$ 10,623,511
25	Net Term Sales	$ (2,643,200)	$ (3,144,552)	$ (2,749,200)	$ (2,635,536)	$ (2,592,189)	$ (2,894,960)	$ (2,749,584)	$ (2,383,872)	$ (2,494,656)	$ (1,477,232)	$ (1,719,256)	$ (1,599,040)	$ (29,083,277)
26	Net Spot Purchases	$ 2,900,017	$ 3,541,250	$ 1,339,041	$ 778,057	$ 1,636,310	$ 2,889,455	$ 2,718,684	$ 2,821,369	$ 1,479,051	$ 179,675	$ 1,897,496	$ 1,958,338	$ 24,138,742
27	Net Spot Sales	$ (139,374)	$ (532,194)	$ (454,258)	$ (724,694)	$ (847,501)	$ (445,591)	$ (440,573)	$ (645,505)	$ (653,937)	$ (127,336)	$ (22,571)	$ (47,120)	$ (5,080,653)
28	Other Tracker Costs	$ 2,532,510	$ 2,464,792	$ 2,054,668	$ 2,007,735	$ 3,264,434	$ 2,217,283	$ 1,804,448	$ 1,818,377	$ 1,763,657	$ 2,594,229	$ 3,368,798	$ 2,222,647	$ 28,113,579
29	Total Electric Supply Expenses	$ 21,603,219	$ 20,869,854	$ 17,093,950	$ 17,762,677	$ 19,900,702	$ 21,755,127	$ 21,114,930	$ 19,027,628	$ 18,740,801	$ 18,667,638	$ 21,564,808	$ 19,460,865	$ 237,562,198
30														
31	NWE Transmission Costs													
32														
33	Other Services (Wheeling)	$ 33,142	$ 81,051	$ 69,835	$ 113,410	$ 128,089	$ 66,577	$ 60,706	$ 92,841	$ 99,197	$ 44,382	$ 6,906	$ 14,968	$ 811,106
34	Ancillary Cost (Disallowed)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (1,418)	$ (17,010)
35	Total NWE Transmission	$ 31,724	$ 79,634	$ 68,417	$ 111,993	$ 126,672	$ 65,160	$ 59,288	$ 91,424	$ 97,780	$ 42,964	$ 5,489	$ 13,550	$ 794,096
36														
37	Administrative Expenses						$ -							
38	MPSC Tax Collection (.0023)	$ 46,428	$ 48,546	$ 44,448	$ 42,208	$ 43,743	$ 47,987	$ 51,013	$ 47,622	$ 45,014	$ 42,967	$ 41,276	$ 42,048	$ 543,300
39	MCC Tax Collection (.0007)	$ 14,130	$ 14,775	$ 13,528	$ 12,846	$ 13,313		$ 15,526	$ 14,494	$ 13,700	$ 13,077	$ 12,562	$ 12,797	$ 150,748
40	Modeling	$ 46,172	$ 46,172	$ 46,172	$ 46,172	$ 46,172	$ 46,172	$ 46,172	$ 46,172	$ 46,172	$ 46,172	$ 46,172	$ 46,172	$ 554,064
41	Trading & Marketing	$ 7,269	$ 7,269	$ 7,269	$ 7,269	$ 7,269	$ 7,269	$ 7,269	$ 7,269	$ 7,269	$ 7,269	$ 7,269	$ 7,269	$ 87,228
42	Administration	$ 20,509	$ 20,509	$ 20,509	$ 20,509	$ 20,509	$ 20,509	$ 20,509	$ 20,509	$ 20,509	$ 20,509	$ 20,509	$ 20,509	$ 246,108
43	Total Administrative Expenses	$ 134,508	$ 137,271	$ 131,926	$ 129,004	$ 131,007	$ 121,937	$ 140,489	$ 136,066	$ 132,663	$ 129,994	$ 127,788	$ 128,796	$ 1,581,448
44														
45	Carrying Cost Expense													
46	Carrying Costs	$ (12,574)	$ (12,791)	$ (26,362)	$ (28,844)	$ (21,470)	$ (14,452)	$ (20,291)	$ (30,055)	$ (34,238)	$ (33,407)	$ (8,715)	$ 0	$ (243,201)
47	Total Carrying Costs	$ (12,574)	$ (12,791)	$ (26,362)	$ (28,844)	$ (21,470)	$ (14,452)	$ (20,291)	$ (30,055)	$ (34,238)	$ (33,407)	$ (8,715)	$ 0	$ (243,201)
48														
49														
50	Total Expenses	$ 21,756,878	$ 21,073,968	$ 17,267,931	$ 17,974,829	$ 20,136,910	$ 21,927,771	$ 21,294,416	$ 19,225,063	$ 18,937,006	$ 18,807,189	$ 21,689,369	$ 19,603,211	$ 239,694,540
51														
52	Deferred Cost Amortization	$ (296,309)	$ (309,904)	$ (283,794)	$ (270,183)	$ (280,560)	$ (307,848)	$ (327,203)	$ (305,455)	$ (288,757)	$ (275,334)	$ (263,359)	$ (268,404)	$ (3,477,111)
53	(under collection)/over collection													
54	Monthly Deferred Cost	$ (1,274,490)	$ 342,815	$ 2,341,233	$ 646,541	$ (837,443)	$ (756,082)	$ 1,212,432	$ 1,785,718	$ 922,915	$ 149,351	$ (3,480,064)	$ (1,052,927)	$ (0)
55	Cumulative Deferred Cost	$ (1,274,490)	$ (931,675)	$ 1,409,558	$ 2,056,099	$ 1,218,656	$ 462,574	$ 1,675,007	$ 3,460,725	$ 4,383,639	$ 4,532,991	$ 1,052,926	$ (0)	

Electric Supply Cost Tracker

Electric Tracker Projection Excluding Generation Assets Cost of Service

	Jul-13 Estimate	Aug-13 Estimate	Sep-13 Estimate	Oct-13 Estimate	Nov-13 Estimate	Dec-13 Estimate	Jan-14 Estimate	Feb-14 Estimate	Mar-14 Estimate	Apr-14 Estimate	May-14 Estimate	Jun-14 Estimate
Note: for supply cost expense positive value reflects an under collection, negative an (over collection).												
Deferred Supply Cost Expense												
Beginning Balance	$ (3,477,111)	$ (1,906,312)	$ (1,939,223)	$ (3,996,662)	$ (4,373,020)	$ (3,255,017)	$ (2,191,087)	$ (3,076,317)	$ (4,556,580)	$ (5,190,738)	$ (5,064,755)	$ (1,321,331)
Monthly Deferred Cost	$ 1,570,799	$ (32,911)	$ (2,057,439)	$ (376,358)	$ 1,118,004	$ 1,063,930	$ (885,230)	$ (1,480,263)	$ (634,158)	$ 125,983	$ 3,743,424	$ 1,321,331
Ending Balance	$ (1,906,312)	$ (1,939,223)	$ (3,996,662)	$ (4,373,020)	$ (3,255,017)	$ (2,191,087)	$ (3,076,317)	$ (4,556,580)	$ (5,190,738)	$ (5,064,755)	$ (1,321,331)	$ 0
Total Capital	$ (1,906,312)	$ (1,939,223)	$ (3,996,662)	$ (4,373,020)	$ (3,255,017)	$ (2,191,087)	$ (3,076,317)	$ (4,556,580)	$ (5,190,738)	$ (5,064,755)	$ (1,321,331)	$ 0

Cost of Capital	Rate	% Capitalization	Rate of Return
Long-Term Debt	5.76%	52.00%	3.00%
Common Equity	10.25%	48.00%	4.92%
Average Cost of Capital			7.92%
Deferred Supply Expense			
Carrying Charge	7.92%		

	A/B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Electric Supply Cost Tracker**													
2	**Electric Tracker Projection**													
3														
4	**Volumes in MWh**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Total**
5		Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
6	**Off System Transactions**													
7	**Fixed Price**													
8	Base Fixed Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Competitive Solicitations	103,400	103,800	99,600	103,800	100,125	103,000	103,400	93,600	103,275	100,400	103,400	100,000	1,217,800
10	Base Fixed Price Sales													-
11	Competitive Solicitations	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Term Fixed Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Term Fixed Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
14	**Index Price**													
15	Base Index Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Base Index Price Sales													-
17	Competitive Solicitations	(29,000)	(29,400)	(27,600)	(29,400)	(28,025)	(28,600)	(29,000)	(26,400)	(28,975)	(28,400)	(29,000)	(28,000)	(341,800)
18	Term Index Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Index Price Sales	(74,400)	(74,400)	(72,000)	(74,400)	(72,100)	(74,400)	(74,400)	(67,200)	(74,300)	(72,000)	(74,400)	(72,000)	(876,000)
20	Spot Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Spot Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
22														
23	**On System Transactions**													
24	**Fixed Price**													
25	Rate-Based Assets													
26	Colstrip Unit 4	151,032	151,032	146,160	151,032	146,160	151,032	151,032	136,416	151,032	146,160	75,516	114,492	1,671,096
27	Dave Gates Generating Station	5,208	5,208	5,040	5,208	5,040	5,208	5,208	4,704	5,208	5,040	5,208	5,040	61,320
28	Spion Kop	8,184	8,184	9,360	14,136	14,400	11,904	17,856	10,752	11,888	11,520	8,928	8,640	135,752
29	Base Fixed Price Purchases													
30	PPL 7 Year Contract	124,200	125,400	118,800	125,400	120,125	123,000	124,200	112,800	124,075	121,200	124,200	120,000	1,463,400
31	Judith Gap	22,884	25,777	27,463	42,957	48,637	53,498	58,235	41,616	43,022	39,172	35,251	28,651	467,163
32	Other Non-QF	13,392	13,392	12,960	13,392	12,978	13,392	13,392	12,096	13,374	12,960	13,392	12,960	157,680
33	Competitive Solicitations	20,800	21,600	19,200	21,600	20,000	20,000	20,800	19,200	20,800	20,800	20,800	20,000	245,600
34	QF Tier II	56,629	37,248	67,118	72,110	69,667	73,022	72,371	66,880	74,590	68,123	74,697	75,155	807,610
35	QF Tier II Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
36	QF-1 Tariff Contracts	7,068	7,068	6,840	8,196	9,004	9,540	18,228	13,776	14,489	12,600	13,368	10,440	130,616
37	Term Fixed Price Purchases	1,950	2,025	1,800	2,025	1,875	1,875	-	-	-	-	-	-	11,550
38	Term Fixed Price Sales	(1,950)	(2,025)	(1,800)	(2,025)	(1,875)	(1,875)	-	-	-	-	-	-	(11,550)
39	**Index Price**													
40	Base Index Price Purchases													
41	Competitive Solicitations	45,400	45,000	44,400	45,000	44,075	45,800	45,400	40,800	45,325	43,600	45,400	44,000	534,200
42	Term Index Price Purchases	62,400	54,000	9,600	10,800	22,978	43,392	20,800	19,200	10,400	10,400	10,400	-	274,370
43	Term Index Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Spot Purchases	68,639	74,116	32,305	20,721	42,779	69,625	68,950	74,679	41,291	6,980	64,717	69,346	634,149
45	Spot Sales	(5,162)	(15,368)	(13,186)	(22,312)	(25,612)	(12,412)	(13,027)	(19,923)	(21,287)	(9,524)	(1,482)	(3,212)	(162,507)
46	Imbalance, Current Month Estimate	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Imbalance, Prior Months True-up	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Imbalance, Accounting & BA Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
49														
50	**Ancillary and Other**													
51	Basin Creek Fixed Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Basin Creek Variable Costs	11,485	14,046	9,528	6,054	5,232	6,610	5,070	3,663	3,072	1,800	2,191	2,390	71,139
53	Operating Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Wind Other Cost													
55	DSM Program & Labor Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
56	DSM Lost T& D Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
57	DSM Lost Revenue Adjustment													
58														
59	**Total Delivered Supply**	592,160	566,703	495,588	514,294	535,463	613,612	608,515	536,659	537,278	490,831	492,585	507,902	6,491,589
60														
61	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
62	**Total Supply Expense**													
63														

	A / B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Electric Supply Cost Tracker**													
2	**Electric Tracker Projection**													
3														
64	**Energy Supply Expense**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Total**
65		Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
66	**Off System Transactions**													
67	**Fixed Price**													
68	Base Fixed Price Purchases													
69	Competitive Solicitations	$ 4,362,240	$ 4,398,960	$ 4,178,880	$ 4,398,960	$ 4,220,180	$ 4,325,520	$ 4,362,240	$ 3,959,040	$ 4,357,660	$ 4,252,320	$ 4,362,240	$ 4,215,600	$ 51,393,840
70	Base Fixed Price Sales													
71	Competitive Solicitations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72	Term Fixed Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	**Index Price**													
75	Base Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76	Base Index Price Sales													
77	Competitive Solicitations	$ (1,100,200)	$ (1,302,162)	$ (1,085,220)	$ (1,064,424)	$ (1,030,547)	$ (1,138,740)	$ (1,097,468)	$ (958,656)	$ (996,192)	$ (637,004)	$ (734,742)	$ (682,160)	$ (11,827,515)
78	Term Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79	Term Index Price Sales	$ (2,643,200)	$ (3,144,552)	$ (2,749,200)	$ (2,635,536)	$ (2,592,189)	$ (2,894,960)	$ (2,749,584)	$ (2,383,872)	$ (2,494,656)	$ (1,477,232)	$ (1,719,256)	$ (1,599,040)	$ (29,083,277)
80	Spot Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81	Spot Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82														
83	**On System Transactions**													
84	**Fixed Price**													
85	Rate-Based Assets													
86	Colstrip Unit 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
87	Dave Gates Generating Station	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88	Spion Kop	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89	Base Fixed Price Purchases													
90	PPL 7 Year Contract	$ 6,557,760	$ 6,621,120	$ 6,272,640	$ 6,627,390	$ 6,348,606	$ 6,500,550	$ 6,570,180	$ 5,967,120	$ 6,563,568	$ 6,417,540	$ 6,576,390	$ 6,354,000	$ 77,376,864
91	Judith Gap	$ 726,580	$ 818,424	$ 871,935	$ 1,363,891	$ 1,544,213	$ 1,698,576	$ 1,848,971	$ 1,321,311	$ 1,365,948	$ 1,243,714	$ 1,119,212	$ 909,654	$ 14,832,430
92	Other Non-QF	$ 780,084	$ 780,084	$ 754,920	$ 780,084	$ 755,969	$ 780,084	$ 782,502	$ 706,776	$ 781,450	$ 757,260	$ 782,502	$ 757,260	$ 9,198,975
93	Competitive Solicitations	$ 1,123,720	$ 1,166,940	$ 1,037,280	$ 1,166,940	$ 1,080,500	$ 1,080,500	$ 1,123,720	$ 1,037,280	$ 1,123,720	$ 1,123,720	$ 1,123,720	$ 1,080,500	$ 13,268,540
94	QF Tier II	$ 2,076,585	$ 1,365,884	$ 2,461,217	$ 2,644,274	$ 2,554,689	$ 2,677,717	$ 2,653,845	$ 2,452,490	$ 2,735,215	$ 2,498,070	$ 2,739,139	$ 2,755,934	$ 29,615,059
95	QF Tier II Adjustments													
96	QF-1 Tariff Contracts	$ 491,397	$ 491,397	$ 475,546	$ 568,748	$ 623,883	$ 659,703	$ 1,216,407	$ 916,907	$ 971,387	$ 856,357	$ 909,737	$ 714,373	$ 8,895,842
97	Term Fixed Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
98	Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
99	**Index Price**													
100	Base Index Price Purchases													
101	Competitive Solicitations	$ 1,444,300	$ 1,746,690	$ 1,564,980	$ 1,475,412	$ 1,465,404	$ 1,654,520	$ 1,553,416	$ 1,337,616	$ 1,400,002	$ 747,228	$ 885,814	$ 820,880	$ 16,096,262
102	Term Index Price Purchases	$ 2,490,800	$ 2,453,220	$ 371,520	$ 375,840	$ 876,751	$ 1,750,509	$ 768,144	$ 677,376	$ 343,928	$ 239,096	$ 276,328	$ -	$ 10,623,511
103	Term Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
104	Spot Purchases	$ 2,900,017	$ 3,541,250	$ 1,339,041	$ 778,057	$ 1,636,310	$ 2,889,455	$ 2,718,684	$ 2,821,369	$ 1,479,051	$ 179,675	$ 1,897,496	$ 1,958,338	$ 24,138,742
105	Spot Sales	$ (139,374)	$ (532,194)	$ (454,258)	$ (724,694)	$ (847,501)	$ (445,591)	$ (440,573)	$ (645,505)	$ (653,937)	$ (127,336)	$ (22,571)	$ (47,120)	$ (5,080,653)
106	Imbalance, Current Month Estimate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
107	Imbalance, Prior Months True-up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
108	Imbalance, Accounting & BA Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
109														
110	**Ancillary and Other**													
111	Basin Creek Fixed Costs	$ 368,817	$ 383,832	$ 376,268	$ 365,422	$ 862,022	$ 378,548	$ 370,210	$ 377,706	$ 361,595	$ 366,247	$ 820,461	$ 361,607	$ 5,392,735
112	Basin Creek Variable Costs	$ 426,206	$ 525,396	$ 354,743	$ 226,172	$ 203,692	$ 268,265	$ 205,098	$ 147,845	$ 123,039	$ 69,388	$ 84,118	$ 92,327	$ 2,726,289
113	Operating Reserves	$ 208,320	$ 208,320	$ 201,600	$ 208,320	$ 201,600	$ 208,320	$ 208,320	$ 188,160	$ 208,320	$ 201,600	$ 208,320	$ 201,600	$ 2,452,800
114	Wind Other Cost	$ 12,360	$ 12,360	$ 12,360	$ 12,360	$ 701,803	$ 12,360	$ 12,360	$ 12,360	$ 12,360	$ 12,360	$ 701,803	$ 12,360	$ 1,527,205
115	DSM Program & Labor Costs	$ 983,840	$ 801,918	$ 576,730	$ 662,495	$ 762,352	$ 816,824	$ 475,494	$ 559,340	$ 525,377	$ 1,411,669	$ 1,021,131	$ 1,021,787	$ 9,618,958
116	DSM Lost T& D Revenues	$ 532,966	$ 532,966	$ 532,966	$ 532,966	$ 532,966	$ 532,966	$ 532,966	$ 532,966	$ 532,966	$ 532,966	$ 532,966	$ 532,966	$ 6,395,592
117	DSM Lost Revenue Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
118														
119	**Total Delivered Supply**	$ 21,603,219	$ 20,869,854	$ 17,093,950	$ 17,762,677	$ 19,900,702	$ 21,755,127	$ 21,114,930	$ 19,027,628	$ 18,740,801	$ 18,667,638	$ 21,564,808	$ 19,460,865	$ 237,562,198
120		Wind Other Cost includes: Judith Gap impact fees and property tax charges, consulting work on met towers, 3 TIER corecasting fees, electric service at met towers, and WREGIS charges.												
121	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
122	**Unit Costs**													
123														

	A B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Electric Supply Cost Tracker**													
2	**Electric Tracker Projection**													
3														
124	**Energy Supply Unit Costs**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Total**
125		Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
126	**Off System Transactions**													
127	**Fixed Price**													
128	Base Fixed Price Purchases													
129	Competitive Solicitations	$ 42.19	$ 42.38	$ 41.96	$ 42.38	$ 42.15	$ 42.00	$ 42.19	$ 42.30	$ 42.19	$ 42.35	$ 42.19	$ 42.16	$ 42.20
130	Base Fixed Price Sales													
131	Competitive Solicitations	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
132	Term Fixed Price Purchases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	#DIV/0!
133	Term Fixed Price Sales	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
134	**Index Price**													
135	Base Index Price Purchases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
136	Base Index Price Sales													
137	Competitive Solicitations	$ 37.94	$ 44.29	$ 39.32	$ 36.20	$ 36.77	$ 39.82	$ 37.84	$ 36.31	$ 34.38	$ 22.43	$ 25.34	$ 24.36	$ 34.60
138	Term Index Price Purchases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
139	Term Index Price Sales	$ 35.53	$ 42.27	$ 38.18	$ 35.42	$ 35.95	$ 38.91	$ 36.96	$ 35.47	$ 33.58	$ 20.52	$ 23.11	$ 22.21	$ 33.20
140	Spot Purchases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
141	Spot Sales	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
142														
143	**On System Transactions**													
144	**Fixed Price**													
145	Rate-Based Assets													
146	Colstrip Unit 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
147	Dave Gates Generating Station	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
148	Spion Kop	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
149	Base Fixed Price Purchases													
150	PPL 7 Year Contract	$ 52.80	$ 52.80	$ 52.80	$ 52.85	$ 52.85	$ 52.85	$ 52.90	$ 52.90	$ 52.90	$ 52.95	$ 52.95	$ 52.95	$ 52.87
151	Judith Gap	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75	$ 31.75
152	Other Non-QF	$ 58.25	$ 58.25	$ 58.25	$ 58.25	$ 58.25	$ 58.25	$ 58.43	$ 58.43	$ 58.43	$ 58.43	$ 58.43	$ 58.43	$ 58.34
153	Competitive Solicitations	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03
154	QF Tier II	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67
155	QF Tier II Adjustments	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
156	QF-1 Tariff Contracts	$ 69.52	$ 69.52	$ 69.52	$ 69.39	$ 69.29	$ 69.15	$ 66.73	$ 66.56	$ 67.05	$ 67.96	$ 68.05	$ 68.43	$ 68.11
157	Term Fixed Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	n/a	n/a	n/a	n/a	n/a	n/a	$ -
158	Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	n/a	n/a	n/a	n/a	n/a	n/a	$ -
159	**Index Price**													
160	Base Index Price Purchases													
161	Competitive Solicitations	$ 31.81	$ 38.82	$ 35.25	$ 32.79	$ 33.25	$ 36.12	$ 34.22	$ 32.78	$ 30.89	$ 17.14	$ 19.51	$ 18.66	$ 30.13
162	Term Index Price Purchases	$ 39.92	$ 45.43	$ 38.70	$ 34.80	$ 38.16	$ 40.34	$ 36.93	$ 35.28	$ 33.07	$ 22.99	$ 26.57	n/a	$ 38.72
163	Term Index Price Sales	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
164	Spot Purchases	$ 42.25	$ 47.78	$ 41.45	$ 37.55	$ 38.25	$ 41.50	$ 39.43	$ 37.78	$ 35.82	$ 25.74	$ 29.32	$ 28.24	$ 38.06
165	Spot Sales	$ 27.00	$ 34.63	$ 34.45	$ 32.48	$ 33.09	$ 35.90	$ 33.82	$ 32.40	$ 30.72	$ 13.37	$ 15.23	$ 14.67	$ 31.26
166	Imbalance, Current Month Estimate	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
167	Imbalance, Prior Months True-up	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
168	Imbalance, Accounting & BA Expense													
169														
170	**Ancillary and Other**													
171	Basin Creek Fixed Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
172	Basin Creek Variable Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
173	Operating Reserves	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
174	Wind Other Cost													
175	DSM Program & Labor Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
176	DSM Lost T& D Revenues	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
177	DSM Lost Revenue Adjustment	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
178														
179														
180	**Total Delivered Supply**	$ 36.48	$ 36.83	$ 34.49	$ 34.54	$ 37.17	$ 35.45	$ 34.70	$ 35.46	$ 34.88	$ 38.03	$ 43.78	$ 38.32	$ 36.60
181														

Tradition — Electricity West

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5/9/2013

MID C	Jun 2013		Jul 2013		Aug 2013		Q3 of 13		Q4 of 13		Q1 of 14		Q2 of 14		Cal 14		Cal 15		Cal 16		Cal 17		Cal 18	
	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer
6x16	29.75	30.75	41.50	42.50	47.25	48.25	43.40	44.40	38.75	39.75	37.25	38.25	27.25	28.25	36.50	37.50	38.00	39.00	39.25	40.25	41.00	42.00	43.25	44.25
6x8+24																								

NP 15	Jun 2013		Jul 2013		Aug 2013		Q3 of 13		Q4 of 13		Q1 of 14		Q2 of 14		Cal 14		Cal 15		Cal 16		Cal 17		Cal 18	
	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer
6x16	42.00	43.00	50.25	51.25	55.00	56.00	51.50	52.50	46.65	47.65	47.75	48.75	41.50	42.50	47.70	48.70	49.00	50.00	50.00	51.00	52.00	53.00	54.50	55.50
6x8+24																								

SP 15	Jun 2013		Jul 2013		Aug 2013		Q3 of 13		Q4 of 13		Q1 of 14		Q2 of 14		Cal 14		Cal 15		Cal 16		Cal 17		Cal 18	
	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer
6x16	48.25	49.25	57.50	58.50	62.00	63.00	58.50	59.50	50.15	51.15	50.50	51.50	47.25	48.25	51.50	52.50	52.25	53.25	53.00	54.00	54.25	55.25	56.25	57.25
6x8+24																								

PV	Jun 2013		Jul 2013		Aug 2013		Q3 of 13		Q4 of 13		Q1 of 14		Q2 of 14		Cal 14		Cal 15		Cal 16		Cal 17		Cal 18	
	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer
6x16	39.00	40.00	49.00	50.00	51.75	52.75	47.65	48.65	37.40	38.40	38.25	39.25	38.25	39.25	40.75	41.75	41.75	42.75	43.00	44.00	44.25	45.25	46.50	47.50
6x8+24																								

Mead 230	Jun 2013		Jul 2013		Aug 2013		Q3 of 13		Q4 of 13		Q1 of 14		Q2 of 14		Cal 14		Cal 15		Cal 16		Cal 17		Cal 18	
	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer	Bid	Offer
6x16	40.50	41.50	50.50	51.50	53.25	54.25	49.90	50.90	39.65	40.65	40.50	41.50	40.50	41.50	42.00	43.00	43.25	44.25	44.50	45.50	45.75	46.75	48.25	49.25
6x8+24																								

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.5.33
Annual Electricity Supply Tracker
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF CHERYL A. HANSEN

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL ELECTRICITY SUPPLY TRACKER

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Witness Information

Q. Please state your name and business address.

A. My name is Cheryl A. Hansen, and my business address is 40 East Broadway, Butte, Montana 59701.

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

A. I am employed by NorthWestern Energy ("NWE" or "NorthWestern") as a Senior Analyst in the Regulatory Affairs Department.

Q. Please summarize your educational and employment experiences.

A. I received a Bachelor of Arts degree in Anthropology from the University of Montana in 1974. I commenced my employment with Montana Power Company and NorthWestern in 1978 and have worked in various positions within the Regulatory Affairs Department. Over the years, I attended various courses and/or seminars on a variety of utility and regulatory subjects, including rate design and marginal costing.

I am a regular participant in the preparation of rate case testimony, exhibits, and workpapers in proceedings before the Montana Public Service Commission ("MPSC" or "Commission") and the Federal Energy Regulatory Commission ("FERC"). I have provided rate design and cost of service support in several rate proceedings and have filed testimony before both the FERC and this Commission.

Purpose of Testimony

Q. What is the purpose of your Annual Electricity Supply Tracker testimony?

A. This testimony:

1. Presents the 2013-2014 tracker year billing statistics and explains how they are derived;
2. Presents the derivation of proposed electricity deferred supply rates resulting from the over/under collection reflected in both the 2011-2012 true-up period and the 2012-2013 true-up period;
3. Presents the derivation of proposed electricity supply rates for the forecasted 2013-2014 tracker period; and
4. Presents the overall total supply rates incorporating all individual rate components.

2013-2014 Tracker Year Billing Statistics

Q. How were the tracker period usage and billing statistics developed?

A. The tracker period usage and billing statistics were developed using the same methodology as that presented in previous NWE filings. The methodology utilizes historical actual billed data, weather adjustments, known changes, and forecasted loads to derive the estimated usage for the July 2013 to June 2014 tracker period.

Q. Explain how cyclical and calendar usage are used in this filing.

A. Cyclical usage represents customer usage billed throughout a calendar month on each of 21 yearly billing cycles that normally include usage for the current and prior month (e.g., a July 15 meter read includes 15 days of usage in July and 15 days of usage in June). Calendar usage, on the other hand, represents a customer's adjusted usage as if it was recorded for the calendar month.

Calendar data is used to determine the cost of energy supply, which is incurred on a calendar basis and is used in the analysis included in the Prefiled Direct Testimony of Frank V. Bennett ("Bennett Direct Testimony"). Cyclical data is used to establish rates for billing purposes and calculate forecasted revenues.

Q. How was the tracker period usage presented in Exhibit__(CAH-1)13-14 developed?

A. Table 1 of Exhibit__(CAH-1)13-14 is actual billed usage for the period April 2012 through March 2013. The subsequent tables show a variety of changes that are made to arrive at the July 2013 through June 2014 forecasted usage shown on Table 5 of the exhibit. A brief description of Tables 1 through 4 in Exhibit__(CAH-1)13-14 is as follows:

1. Table 1 is actual billed usage for 12 months ended March 2013.

2. Table 2 is the result of shifting data to calendar month primarily using the Load Vision computer program. Load Vision shifts data

to calendar month by using actual hourly metered data for the larger customers, individual meter read data for smaller General Service – 1 ("GS-1") and Residential customers, monthly hours of darkness for lighting, and actual meter reads and historical load research shapes for irrigation.

3. Table 3 is Table 2 adjusted for known changes and forecast information for the Residential and GS-1 customer classes.

4. Table 4 summarizes the changes shown on Table 3 as described below:

   - Column C shows the actual billed usage for the 12 months ended March 2013 as reflected on Table 1.
   - Column D shows changes in the operations of large customers. Changes include a decrease in load for one customer who is no longer active, adjusting loads for two customers to normal year usage, and increasing loads for two customers to reflect expansion plans. Overall, the adjustment in Column D shows an increase of 9,892 megawatt-hours ("MWh") in electric supply usage.
   - Column E replaces the actual irrigation load with a six-year average resulting in a decrease of 21,410 MWh to non-choice usage. This is offset by an increase of 2,950 MWh to represent customer movement from choice back to non-

choice. The net adjustment in Column E shows a decrease of 18,460 MWh to electric supply usage.

- Column F shows changes to the Residential and GS-1 Secondary classes as a result of their forecasted usage for the 12 months ended June 2014. The changes reflect the effects of normal weather, customer growth, and demand-side management activities for these groups. The total usage for each of these groups is based on regression models that predict annual usage for each group as a function of historical usage per customer, number of customers, heating degree days, and cooling degree days. The annual usage is shaped to calendar months using the average monthly shapes from prior test periods. The net impact of the forecast and calendar month adjustments as shown in Column F is a 70,379 MWh increase to electric supply usage.
- Column G is the resulting forecasted usage for the July 2013 through June 2014 time period.
- Column H reflects the sum of all changes (Columns D through F). The total result is a forecasted increase of 61,811 MWh to electric supply usage for the 2013-2014 tracker period.

Q. Describe the adjustments made in Table 5 of Exhibit__(CAH-1)13-14.

A. Again, Table 3 is forecasted calendar month usage with the known change adjustments described above. Table 5 modifies Table 3 by making two adjustments. First, the calendar usage data is shifted back to billed cyclical data. This cyclical adjustment is made to the Residential, GS-1 Secondary, GS-1 Primary, and Irrigation customer classes, as well as to Yellowstone National Park ("YNP"). The GS-2 (Substation and Transmission) customer class consists primarily of the large industrial customers, whose usage remains fairly constant throughout the year, and, therefore, a cyclical billing adjustment is unnecessary. Second, Lighting customers are billed a flat amount of kilowatt hours each month; therefore the total usage is spread evenly as one-twelfth in each month.

Q. Please describe Table 6 of Exhibit__(CAH-1)13-14.

A. Table 6 is a subset of Table 5 showing only those loads applicable to electric supply purchases and that is used in the Bennett Direct Testimony.

It is necessary to make several adjustments to Table 5 in order to provide the appropriate loads for rate design purposes. These adjustments do not affect total load, but provide the detail required in the derivation of rates. The loads for the Residential class are allocated between Residential and Residential Employee using a ratio based on actual historical usage. The loads for the GS-1 Secondary and GS-1 Primary are allocated to Non-Demand Metered and Demand Metered using a ratio based on actual historical usage. These changes are reflected on Table 6 of Exhibit__(CAH-1)13-14 for use in the derivation of rates.

Q. Please explain how the YNP loads are treated in the derivation of rates process.

A. The loads for YNP are served by the utility and are included in the total delivered load shown in the tables discussed above. However, the costs for YNP are recovered through a separately negotiated contract rate; therefore, the loads and corresponding revenues associated with YNP are excluded from any rate design for MPSC jurisdictional rates. The loads for YNP are included only in the derivation of electricity supply rates. If the YNP rate were to include additional allocations related to Colstrip Unit 4 ("CU4"), the Dave Gates Generating Station ("DGGS"), and the Spion Kop Wind Generation Asset ("Spion"), the resulting revenue would be very small and not worth the administrative burden. Therefore, only the electricity supply rate derivation includes a revenue credit related to the YNP customer class.

Derivation of Proposed Deferred Electricity Supply Rates

Q. What is the electricity supply cost account balance for the 12-month period ending June 2013?

A. The electricity supply cost account balance for the 12-month period ending June 2013 is an over-collection of $(3,477,111) as presented on page 1 of Exhibit__(CAH-2)13-14. As discussed below, this includes the prior period balance for the 2011-2012 tracker period and the current period balance for the 2012-2013 tracker period.

Q. Describe the status of the deferred electricity supply cost account balance associated with the 2011-2012 tracker period.

A. In the annual filing submitted on May 31, 2012, the net deferred account balance for the 2011-2012 tracker period was shown as an under-collection of $11,496,428. This amount becomes the starting balance in this filing. Added to this balance is the prior period true-up for the 2 months of estimated data included in the May 2012 filing. Page 1 of Exhibit__(CAH-2)13-14 shows the true-up of the previously estimated months of May and June 2012 with actual data for these months. The resulting actual under-collected ending balance of $15,312,718 is the deferred account beginning balance for the 2012-2013 tracker period. This balance is then combined with the current year monthly activity shown on Exhibit__(CAH-2)13-14, page 1, resulting in a net under-collected balance of $2,773,682 for the 2011-2012 tracker period. The months of April, May and June 2013 are estimated and will be trued-up in the next annual electric supply filing.

Q. Describe the electricity supply cost account balance associated with the 2012-2013 tracking period.

A. Page 2 of Exhibit__(CAH-2)13-14 shows the monthly detail of the difference between the electricity supply cost revenues and expenses for the 2012-2013 tracker period, resulting in an over-collected amount of $(6,250,793). The months of April, May and June 2013 are estimated and will be trued-up in the next annual electric supply filing.

Q. What is the total deferred electricity supply cost account adjustment proposed for amortization in this filing?

A. The total deferred electricity supply cost account adjustment proposed in this filing is an over-collection of $(3,477,111) shown below and on page 1, line 56 of Exhibit__(CAH-2)13-14.

Total Electric Deferred Supply Cost Account Balance

2011-2012 Prior Period Supply Cost Account Balance	$2,773,682
2012-2013 Current Period Supply Cost Account Balance	$(6,250,793)
	$(3,477,111)

Derivation of the deferred electricity supply rates is shown on Exhibit__(CAH-2)13-14, page 3 with the resulting rates and revenues shown on page 4.

Derivation of Proposed Electricity Supply Rates

Q. Please describe the process used by NorthWestern to derive the proposed 2013-2014 forecasted electricity supply rates in this filing.

A. The rate design methodology used in this filing to derive the proposed 2013-2014 forecasted electricity supply rates is the same as that presented in previous electricity supply tracker filings. All forecasted costs are from Exhibit__(FVB-2)13-14 of the Bennett Direct Testimony and are discussed therein.

Derivation of the electricity supply rates is shown on Exhibit__(CAH-2)13-14, pages 5 and 6. The total proposed electricity supply cost of $239,694,540 from Exhibit__(FVB-2)13-14 is used as the starting point shown on page 5. This amount is then reduced for the supply revenues received from YNP. The forecasted loads from Exhibit__(CAH-1)13-14 are adjusted for the employee discount and weighted by losses. A unit rate is calculated and then adjusted for losses by rate class to derive electricity supply base rates. These base rates are further adjusted on page 6 so that the percentage rate increase for each customer class is no greater than the Residential customer rate class increase. The resulting rates are the electricity supply rates proposed in this filing.

Page 7 of Exhibit__(CAH-2)13-14 reflects the electricity supply rates and revenues in summarized format.

Proposed Total Deferred Supply Rates

Q. What is the net deferred supply cost account adjustment proposed for amortization in this filing?

A. The net deferred supply cost account adjustment proposed in this filing is an over-collection of $(746,835). The adjustment consists of the following:

Net Deferred Supply Cost Account Balance

Total Deferred Electricity Supply Over-Collected Balance	$(3,477,111)
Total Deferred CU4 Variable Over-Collected Balance	$(1,868,066)
Total Deferred DGGS Variable Under-Collected Balance	$4,598,342
	$(746,835)

The deferred CU4 variable rate design is shown on page 3 of Exhibit__(CAH-3)13-14 and is addressed in, and included with, the Annual CU4 True-up section of my testimony. The deferred DGGS variable rate design is shown on page 3 of Exhibit__(CAH-4)13-14 and is addressed in, and included with, the Annual DGGS True-up section of my testimony.

The individual rate components are then combined into a single deferred rate for use in billing the ratepayer. The net total deferred supply rate is shown on page 1 of Exhibit__(CAH-6)13-14. The total deferred supply revenue of $(751,388), including rounding, is shown on Exhibit__(CAH-6)13-14, page 2, column T, line 39.

Proposed Total Supply Rates

Q. Please describe the process used by NorthWestern to derive the total 2013-2014 electric supply rates proposed in this filing.

A. The total electric supply rate currently includes several separate rate components – an electricity supply tracker rate, a CU4 fixed cost of service rate, a CU4 variable rate, a DGGS fixed cost of service rate, a DGGS variable rate, a Spion fixed cost of service rate, and a Spion variable rate. See page 7 of Exhibit__(CAH-2)13-14 for proposed electricity supply rates; page 6 of Exhibit__(CAH-3)13-14 for proposed CU4 fixed and variable rates; page 6 of Exhibit__(CAH-4)13-14 for proposed DGGS fixed and variable rates; and page 2 of Exhibit__(CAH-5)13-14 for proposed Spion fixed and variable rates. Note that the CU4, DGGS, and Spion fixed rates remain unchanged from current rates. All of the individual fixed and variable rate components are bundled together into a single rate for customer billing as shown on Exhibit__(CAH-6)13-14, page 3 with the resulting revenues by rate component shown on page 4 and listed below:

Net Supply Revenue

Total Supply Revenue at Current Rates	$376,660,580
Electricity Supply Revenue at Proposed Rates	238,472,742
CU4 Fixed Revenue at Current Rates	75,915,751
CU4 Variable Revenue at Proposed Rates	25,837,848
DGGS Fixed Revenue at Current Rates	28,586,541
DGGS Variable Revenue at Proposed Rates	12,215,388
Spion Fixed Revenue at Current Rates	6,245,924
Spion Variable Revenue at Proposed Rates	83,795
Total Supply Revenue at Proposed Rates	$387,357,989
Net Proposed Total Supply Revenue Change	$10,697,409

Q. Have you provided a summary of the unit rates and resulting revenues proposed in this filing?

A. Yes. The total supply rates (the summation of all the individual rate components) and total supply revenues are shown on Exhibit__(CAH-6)13-14, page 5.

Q. What is NWE's proposal for rate implementation?

A. NWE proposes an interim rate effective date for its proposed rate adjustments and implementation of monthly electric supply adjustments for service on and after July 1, 2013.

Q. Does this conclude your Annual Electricity Supply Tracker testimony?

A. Yes, it does.

TABLE 1 - Actual billing cycle data

NorthWestern Energy Actual Revenue Month Sales in MWH

Class	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Total
Residential Non-Choice	187,781	169,473	170,267	187,129	206,131	188,362	159,939	182,446	220,429	258,306	230,908	210,399	2,371,570
Residential Choice	9	8	9	10	13	11	9	8	10	8	7	1	103
Total Residential	**187,790**	**169,481**	**170,276**	**187,139**	**206,144**	**188,373**	**159,948**	**182,454**	**220,439**	**258,314**	**230,915**	**210,400**	**2,371,672**
GS Secondary Non-Choice	214,665	211,897	220,111	232,995	249,545	245,407	214,381	204,224	224,883	239,838	225,680	218,382	2,702,006
GS Secondary Choice	6,828	6,057	6,382	6,658	7,031	6,771	6,030	5,304	5,544	5,701	5,506	5,245	73,058
GS Primary Non-Choice	27,500	26,014	26,327	27,799	30,055	29,161	28,721	29,953	29,766	30,368	29,363	25,505	340,534
GS Primary Choice	6,090	5,802	5,953	6,072	6,453	6,098	5,436	5,734	5,129	5,234	5,630	5,467	69,096
Total General Service - 1	**255,083**	**249,770**	**258,773**	**273,524**	**293,084**	**287,437**	**254,568**	**245,215**	**265,322**	**281,141**	**266,179**	**254,598**	**3,184,694**
GS Substation Non-Choice	17,716	17,369	16,426	17,015	19,407	19,151	18,641	19,498	17,963	20,440	19,461	18,255	221,340
GS Substation Choice	139,205	105,270	120,677	131,759	140,437	140,983	134,640	122,512	145,627	143,115	144,091	127,109	1,595,425
GS Transmission Non-Choice	10,489	9,818	8,750	10,416	12,272	10,208	10,329	9,243	9,483	11,187	12,456	10,073	124,725
GS Transmission Choice	10,998	10,698	10,733	9,269	10,669	11,878	11,066	12,114	12,132	12,947	13,330	12,172	138,007
Total General Service - 2	**178,407**	**143,155**	**156,586**	**168,459**	**182,785**	**182,220**	**174,677**	**163,368**	**185,206**	**187,688**	**189,338**	**167,609**	**2,079,498**
Irrigation Non-Choice	8	2,901	15,946	29,034	29,326	20,013	9,268	1,022	4	-21	3	2	107,505
Irrigation Choice	0	28	25	42	42	42	17	7	0	0	0	0	203
Total Irrigation	**8**	**2,929**	**15,972**	**29,075**	**29,368**	**20,056**	**9,284**	**1,028**	**4**	**-21**	**3**	**2**	**107,707**
Lighting Non-Choice	4,781	4,786	4,775	4,763	4,762	4,800	4,808	4,796	4,886	4,891	4,862	4,844	57,754
Lighting Choice	365	365	365	365	365	365	365	365	365	365	365	365	4,380
Total Lighting	**5,146**	**5,151**	**5,140**	**5,128**	**5,127**	**5,165**	**5,173**	**5,161**	**5,251**	**5,256**	**5,227**	**5,208**	**62,134**
Yellowstone Contract	669	976	3,327	3,924	1,502	2,621	2,162	1,481	671	555	532	568	18,987
Total Yellowstone	**669**	**976**	**3,327**	**3,924**	**1,502**	**2,621**	**2,162**	**1,481**	**671**	**555**	**532**	**568**	**18,987**
REC Silicon	70,758	66,657	68,627	64,728	68,910	68,923	67,796	68,544	67,943	71,347	70,123	62,076	816,432
Special Contract	**70,758**	**66,657**	**68,627**	**64,728**	**68,910**	**68,923**	**67,796**	**68,544**	**67,943**	**71,347**	**70,123**	**62,076**	**816,432**
Total Distribution	**697,861**	**638,118**	**678,701**	**731,977**	**786,921**	**754,795**	**673,607**	**667,251**	**744,836**	**804,280**	**762,317**	**700,461**	**8,641,124**
Total Electric Supply Usage	463,609	443,232	465,929	513,074	553,001	519,724	448,248	452,663	508,086	565,563	523,265	488,027	5,944,421
Total Choice Usage	234,253	194,886	212,772	218,902	233,920	235,071	225,358	214,588	236,750	238,717	239,051	212,435	2,696,702
	697,861	**638,118**	**678,701**	**731,977**	**786,921**	**754,795**	**673,607**	**667,251**	**744,836**	**804,280**	**762,317**	**700,461**	**8,641,124**

TABLE 2 - Calendar month sales from Load Vision

NorthWestern Energy Calendar Month Sales (MWh)

Class	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Total
Residential Non-Choice	190,521	168,191	165,265	168,060	211,700	196,129	158,613	182,024	202,090	249,042	249,063	205,676	2,346,372
Residential Choice	9	8	8	9	14	11	8	8	9	8	7	1	100
Total Residential	**190,530**	**168,199**	**165,273**	**168,069**	**211,714**	**196,140**	**158,621**	**182,032**	**202,099**	**249,050**	**249,070**	**205,677**	**2,346,472**
GS Secondary Non-Choice	220,946	210,241	213,961	220,025	254,137	251,503	217,310	216,132	214,041	233,548	238,479	208,110	2,698,433
GS Secondary Choice	6,929	5,852	6,300	6,242	7,143	7,035	6,138	5,563	5,464	5,526	5,718	5,083	72,992
GS Primary Non-Choice	28,851	26,597	26,592	27,114	30,291	30,315	29,384	31,068	30,759	32,748	33,082	28,026	354,827
GS Primary Choice	6,068	5,765	5,936	6,062	6,440	6,195	5,373	5,713	5,255	5,219	5,592	5,576	69,195
Total General Service - 1	**262,793**	**248,455**	**252,790**	**259,443**	**298,011**	**295,048**	**258,205**	**258,475**	**255,519**	**277,041**	**282,870**	**246,795**	**3,195,447**
GS Substation Non-Choice	20,724	19,417	18,391	18,134	20,154	20,020	18,949	20,138	18,844	19,912	20,301	18,760	233,743
GS Substation Choice	136,820	103,068	119,294	130,483	139,008	139,650	133,189	133,842	131,155	140,885	141,796	125,337	1,574,526
GS Transmission Non-Choice	10,172	9,869	9,261	9,651	12,377	10,785	10,047	9,389	9,471	10,980	12,452	10,282	124,736
GS Transmission Choice	10,998	10,698	10,733	9,269	10,669	11,878	11,066	12,114	12,150	12,947	13,312	12,172	138,007
Total General Service - 2	**178,713**	**143,053**	**157,680**	**167,536**	**182,208**	**182,334**	**173,251**	**175,483**	**171,619**	**184,723**	**187,862**	**166,551**	**2,071,013**
Irrigation Non-Choice	1	627	10,013	25,397	32,153	23,003	12,288	2,174	38	15	29	6	105,745
Irrigation Choice	0	0	23	21	42	40	27	8	0	1	8	0	170
Total Irrigation	**1**	**627**	**10,013**	**25,397**	**32,153**	**23,003**	**12,288**	**2,174**	**38**	**15**	**29**	**6**	**105,915**
Lighting Non-Choice	5,137	4,046	3,586	3,117	3,588	4,033	4,519	5,792	5,809	6,538	6,499	4,949	57,614
Lighting Choice	385	311	273	237	281	303	345	443	433	486	479	370	4,345
Total Lighting	**5,522**	**4,357**	**3,859**	**3,354**	**3,868**	**4,336**	**4,865**	**6,235**	**6,242**	**7,024**	**6,978**	**5,320**	**61,959**
Yellowstone Contract	878	1,150	2,320	2,241	2,529	2,560	2,294	1,436	905	916	1,038	967	19,234
Total Yellowstone	**878**	**1,150**	**2,320**	**2,241**	**2,529**	**2,560**	**2,294**	**1,436**	**905**	**916**	**1,038**	**967**	**19,234**
REC Silicon	70,758	66,657	68,627	64,728	68,910	68,923	67,796	68,544	67,943	71,347	70,123	62,076	816,431
Special Contract	**70,758**	**66,657**	**68,627**	**64,728**	**68,910**	**68,923**	**67,796**	**68,544**	**67,943**	**71,347**	**70,123**	**62,076**	**816,431**
Total Distribution	**709,196**	**632,498**	**660,562**	**690,768**	**799,394**	**772,343**	**677,319**	**694,380**	**704,365**	**790,116**	**797,969**	**687,390**	**8,616,470**
Total Electric Supply Usage	477,231	440,137	449,390	473,739	566,929	538,348	453,404	468,153	481,956	553,699	560,943	476,775	5,940,705
Total Choice Usage	231,965	192,360	211,195	217,049	232,507	234,035	223,942	226,234	222,409	236,419	237,034	210,615	2,675,766
	709,196	**632,498**	**660,585**	**690,788**	**799,436**	**772,383**	**677,347**	**694,387**	**704,365**	**790,118**	**797,977**	**687,390**	**8,616,470**

TABLE 3: Table 2 adjusted for known changes & forecast information.

NorthWestern Energy Sales in MWH - With Forecast and Known Change Adjustments

Class	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Total
Residential Non-Choice	196,149	185,249	160,682	183,551	208,621	254,553	247,937	215,351	200,873	176,944	166,980	163,018	2,359,909
Residential Choice	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Residential	**196,149**	**185,249**	**160,682**	**183,551**	**208,621**	**254,553**	**247,937**	**215,351**	**200,873**	**176,944**	**166,980**	**163,018**	**2,359,909**
GS Secondary Non-Choice	255,023	251,157	221,465	222,142	219,995	241,779	241,672	218,097	228,793	214,058	218,823	224,229	2,757,232
GS Secondary Choice	6,587	6,487	5,720	5,738	5,682	6,245	6,242	5,633	5,909	5,529	5,652	5,792	71,215
GS Primary Non-Choice	30,733	30,764	29,768	31,082	30,759	32,748	33,082	28,026	29,325	26,997	26,995	27,500	357,777
GS Primary Choice	5,998	5,747	4,989	5,699	5,255	5,219	5,592	5,576	5,594	5,365	5,533	5,676	66,244
Total General Service - 1	**298,341**	**294,155**	**261,943**	**264,660**	**261,691**	**285,991**	**286,587**	**257,331**	**269,621**	**251,949**	**257,003**	**263,197**	**3,252,469**
GS Substation Non-Choice	20,016	19,931	18,866	20,049	18,758	19,764	20,227	18,760	20,619	19,326	18,296	18,058	232,670
GS Substation Choice	139,008	139,650	133,189	133,842	131,155	140,885	141,796	125,337	136,820	120,734	126,825	130,483	1,599,722
GS Transmission Non-Choice	13,634	11,883	11,065	10,123	10,541	11,247	12,452	10,282	11,536	11,202	10,631	11,105	135,701
GS Transmission Choice	13,472	13,684	13,424	13,230	13,231	14,063	14,428	13,180	13,747	13,619	13,165	12,507	161,748
Total General Service - 2	**186,130**	**185,148**	**176,544**	**177,244**	**173,686**	**185,958**	**188,903**	**167,559**	**182,721**	**164,880**	**168,916**	**172,152**	**2,129,842**
Irrigation Non-Choice	26,170	18,731	10,011	1,773	31	13	30	5	1	510	8,159	20,661	86,095
Irrigation Choice	42	30	16	3	0	0	0	0	0	1	13	33	138
Total Irrigation	**26,213**	**18,761**	**10,027**	**1,776**	**31**	**13**	**30**	**5**	**1**	**511**	**8,172**	**20,694**	**86,233**
Lighting Non-Choice	3,588	4,033	4,519	5,792	5,809	6,538	6,499	4,949	5,137	4,046	3,586	3,117	57,614
Lighting Choice	281	303	345	443	433	486	479	370	385	311	273	237	4,345
Total Lighting	**3,868**	**4,336**	**4,865**	**6,235**	**6,242**	**7,024**	**6,978**	**5,320**	**5,522**	**4,357**	**3,859**	**3,354**	**61,959**
Yellowstone Contract	2,529	2,560	2,294	1,436	905	916	1,038	967	878	1,150	2,320	2,241	19,234
Total Yellowstone	**2,529**	**2,560**	**2,294**	**1,436**	**905**	**916**	**1,038**	**967**	**878**	**1,150**	**2,320**	**2,241**	**19,234**
REC Silicon	68,910	68,923	67,796	68,544	67,943	71,347	70,123	62,076	70,758	66,657	68,627	64,728	816,431
Special Contract	**68,910**	**68,923**	**67,796**	**68,544**	**67,943**	**71,347**	**70,123**	**62,076**	**70,758**	**66,657**	**68,627**	**64,728**	**816,431**
Total Distribution	**782,141**	**759,132**	**684,150**	**703,446**	**719,119**	**805,803**	**801,597**	**708,608**	**730,374**	**666,448**	**675,877**	**689,383**	**8,726,077**
Total Electric Supply Usage	547,843	524,307	458,670	475,948	495,419	567,559	562,938	496,436	497,161	454,233	455,789	469,929	6,006,232
Total Choice Usage	234,298	234,824	225,479	227,498	223,699	238,244	238,660	212,172	233,213	212,215	220,088	219,454	2,719,845
	782,141	**759,132**	**684,150**	**703,446**	**719,119**	**805,803**	**801,597**	**708,608**	**730,374**	**666,448**	**675,877**	**689,383**	**8,726,077**

TABLE 4 - Comparison of Tables 1 & 3

NorthWestern Energy Sales (MWh)

Class	Table 1	Lg Cust Known Changes	Irrig Adj & Choice/ NonChoice Movement	Res/GS-1 Forecasts & Shift to Calendar Month	Table 3	Diff MWH	% Diff	Changes
Residential Non-Choice	2,371,570			-11,661	2,359,909	-11,661	-0.49%	Replaced actual with forecast for 12 months ended June 2014.
Residential Choice	103			-103	0	-103	-100.00%	Only one residential choice account as of May 2013.
Total Residential	**2,371,672**	**0**	**0**	**-11,764**	**2,359,909**	**-11,764**	**-0.50%**	
GS Secondary Non-Choice	2,702,006			55,226	2,757,232	55,226	2.04%	Replaced actual with forecast for 12 months ended June 2014.
GS Secondary Choice	73,058			-1,842	71,215	-1,842	-2.52%	Replaced with forecast and a few accounts moved back to non-choice.
GS Primary Non-Choice	340,534		2,950	14,293	357,777	17,243	5.06%	Shift to calendar (14,293) and movement from choice to default (2,950).
GS Primary Choice	69,096		-2,950	98	66,244	-2,852	-4.13%	Shift to calendar (98) and movement from choice to default (-2,950).
Total General Service - 1	**3,184,694**	**0**	**0**	**67,775**	**3,252,469**	**67,775**	**2.13%**	
GS Substation Non-Choice	221,340	-1,073		12,403	232,670	11,330	5.12%	Shift to calendar/part of 1 cust choice in Tbl 2 (12,403). 1 cust no longer active (-1,073).
GS Substation Choice	1,595,425	25,196		-20,898	1,599,722	4,298	0.27%	Shift to calendar/part of 1 cust choice in Tbl 2 (-20,899). 1 cust normal usage (25,196).
GS Transmission Non-Choice	124,725	10,965		11	135,701	10,976	8.80%	Shift to calendar (11). Incr 1 cust to account for normal yr (10,965).
GS Transmission Choice	138,007	23,741			161,748	23,741	17.20%	Incr 1 cust for expansions (6,076 & 4,525). Incr 1 cust for expansion (13,140).
Total General Service - 2	**2,079,498**	**58,829**	**0**	**-8,485**	**2,129,841**	**50,344**	**2.42%**	
Irrigation Non-Choice	107,505		-21,410		86,095	-21,410	-19.92%	Replaced actuals with 6 year average
Irrigation Choice	203			-64	138	-64	-31.66%	
Total Irrigation	**107,707**	**0**	**-21,410**	**-64**	**86,233**	**-21,474**	**-19.94%**	
Lighting Non-Choice	57,754			-140	57,614	-140	-0.24%	Shift to calendar month.
Lighting Choice	4,380			-35	4,345	-35	-0.79%	
Total Lighting	**62,134**	**0**	**0**	**-175**	**61,959**	**-175**	**-0.28%**	
Yellowstone Contract	18,987			247	19,234	247	1.30%	
Total Yellowstone	**18,987**	**0**	**0**	**247**	**19,234**	**247**	**1.30%**	
REC Silicon	816,432			0	816,431	0	0.00%	
Special Contract	**816,432**	**0**	**0**	**0**	**816,431**	**0**	**0.00%**	
Total Distribution	**8,641,124**	**58,829**	**-21,410**	**47,534**	**8,726,077**	**84,953**	**0.98%**	
Total Electric Supply Usage	5,944,421	9,892	-18,460	70,379	6,006,232	61,811	1.04%	
Total Choice Usage	2,696,702	48,937	-2,950	-22,845	2,719,845	23,142	0.86%	
	8,641,124	**58,829**	**-21,410**	**47,534**	**8,726,077**	**84,953**	**0.98%**	
		-	-	-	-			

TABLE 5: Table 3 shifted for cyclical billing.

NorthWestern Energy Sales in MWH - Shifted to Cyclical Month

Class	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Total
Residential Non-Choice	179,584	190,699	172,966	172,117	196,086	231,587	251,245	231,644	208,112	188,908	171,962	164,999	2,359,909
Residential Choice	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Residential	**179,584**	**190,699**	**172,966**	**172,117**	**196,086**	**231,587**	**251,245**	**231,644**	**208,112**	**188,908**	**171,962**	**164,999**	**2,359,909**
GS Secondary Non-Choice	239,626	253,090	236,311	221,804	221,068	230,887	241,726	229,884	223,445	221,425	216,441	221,526	2,757,232
GS Secondary Choice	6,189	6,537	6,104	5,729	5,710	5,963	6,243	5,938	5,771	5,719	5,590	5,722	71,215
GS Primary Non-Choice	29,117	30,748	30,266	30,425	30,920	31,753	32,915	30,554	28,675	28,161	26,996	27,248	357,777
GS Primary Choice	5,837	5,873	5,368	5,344	5,477	5,237	5,405	5,584	5,585	5,480	5,449	5,605	66,244
Total General Service - 1	**280,769**	**296,248**	**278,049**	**263,301**	**263,175**	**273,841**	**286,289**	**271,959**	**263,476**	**260,785**	**254,476**	**260,100**	**3,252,469**
GS Substation Non-Choice	20,016	19,931	18,866	20,049	18,758	19,764	20,227	18,760	20,619	19,326	18,296	18,058	232,670
GS Substation Choice	139,008	139,650	133,189	133,842	131,155	140,885	141,796	125,337	136,820	120,734	126,825	130,483	1,599,722
GS Transmission Non-Choice	13,634	11,883	11,065	10,123	10,541	11,247	12,452	10,282	11,536	11,202	10,631	11,105	135,701
GS Transmission Choice	13,472	13,684	13,424	13,230	13,231	14,063	14,428	13,180	13,747	13,619	13,165	12,507	161,748
Total General Service - 2	**186,130**	**185,148**	**176,544**	**177,244**	**173,686**	**185,958**	**188,903**	**167,559**	**182,721**	**164,880**	**168,916**	**172,152**	**2,129,842**
Irrigation Non-Choice	23,416	22,451	14,371	5,892	902	22	22	18	3	256	4,334	14,410	86,095
Irrigation Choice	38	36	23	9	1	0	0	0	0	0	7	23	138
Total Irrigation	**23,453**	**22,487**	**14,394**	**5,901**	**904**	**22**	**22**	**18**	**3**	**256**	**4,341**	**14,433**	**86,233**
Lighting Non-Choice	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	57,614
Lighting Choice	362	362	362	362	362	362	362	362	362	362	362	362	4,345
Total Lighting	**5,163**	**5,163**	**5,163**	**5,163**	**5,163**	**5,163**	**5,163**	**5,163**	**5,163**	**5,163**	**5,163**	**5,163**	**61,959**
Yellowstone Contract	2,385	2,545	2,427	1,865	1,171	911	977	1,002	922	1,014	1,735	2,280	19,234
Total Yellowstone	**2,385**	**2,545**	**2,427**	**1,865**	**1,171**	**911**	**977**	**1,002**	**922**	**1,014**	**1,735**	**2,280**	**19,234**
REC Silicon	68,910	68,923	67,796	68,544	67,943	71,347	70,123	62,076	70,758	66,657	68,627	64,728	816,431
Special Contract	**68,910**	**68,923**	**67,796**	**68,544**	**67,943**	**71,347**	**70,123**	**62,076**	**70,758**	**66,657**	**68,627**	**64,728**	**816,431**
Total Distribution	**746,394**	**771,213**	**717,338**	**694,136**	**708,127**	**768,829**	**802,723**	**739,421**	**731,155**	**687,664**	**675,221**	**683,855**	**8,726,077**
													-
Total Electric Supply Usage	512,578	536,148	491,072	467,075	484,248	530,972	564,365	526,945	498,113	475,093	455,195	464,427	6,006,232
Total Choice Usage	233,816	235,065	226,266	227,061	223,879	237,857	238,358	212,477	233,042	212,571	220,026	219,428	2,719,845
	746,394	**771,213**	**717,338**	**694,136**	**708,127**	**768,829**	**802,723**	**739,421**	**731,155**	**687,664**	**675,221**	**683,855**	**8,726,077**

TABLE 6 - Table 5 modified for rate design

NorthWestern Energy Revenue Month Sales (MWh) - Electric Supply Rate Design Load

Class	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Total
Residential Non-Choice	179,288	190,385	172,681	171,833	195,763	231,206	250,832	231,263	207,769	188,597	171,678	164,727	2,356,022
Residential Employee	296	314	285	283	323	381	414	382	343	311	283	272	3,887
Total Residential	**179,584**	**190,699**	**172,966**	**172,117**	**196,086**	**231,587**	**251,245**	**231,644**	**208,112**	**188,908**	**171,962**	**164,999**	**2,359,909**
	-	-	-	-	-	-	-	-	-	-	-	-	-
GS Secondary Non-Demand	24,279	25,643	23,943	22,473	22,398	23,393	24,491	23,292	22,639	22,435	21,930	22,445	279,361
GS Secondary Demand	215,347	227,447	212,368	199,331	198,670	207,494	217,234	206,593	200,806	198,991	194,511	199,081	2,477,871
Total GS-1 Secondary	**239,626**	**253,090**	**236,311**	**221,804**	**221,068**	**230,887**	**241,726**	**229,884**	**223,445**	**221,425**	**216,441**	**221,526**	**2,757,232**
	-	-	-	-	-	-	-	-	-	-	-	-	-
GS Primary Non-Demand	46	48	48	48	49	50	52	48	45	44	43	43	563
GS Primary Demand	29,071	30,700	30,218	30,377	30,872	31,703	32,863	30,505	28,630	28,117	26,954	27,205	357,214
Total GS-1 Primary	**29,117**	**30,748**	**30,266**	**30,425**	**30,920**	**31,753**	**32,915**	**30,554**	**28,675**	**28,161**	**26,996**	**27,248**	**357,777**
	-	-	-	-	-	-	-	-	-	-	-	-	-
Total GS-2 Substation	**20,016**	**19,931**	**18,866**	**20,049**	**18,758**	**19,764**	**20,227**	**18,760**	**20,619**	**19,326**	**18,296**	**18,058**	**232,670**
Total GS-2 Transmission	**13,634**	**11,883**	**11,065**	**10,123**	**10,541**	**11,247**	**12,452**	**10,282**	**11,536**	**11,202**	**10,631**	**11,105**	**135,701**
Total Irrigation	**23,416**	**22,451**	**14,371**	**5,892**	**902**	**22**	**22**	**18**	**3**	**256**	**4,334**	**14,410**	**86,095**
Total Lighting	**4,801**	**4,801**	**4,801**	**4,801**	**4,801**	**4,801**	**4,801**	**4,801**	**4,801**	**4,801**	**4,801**	**4,801**	**57,614**
MPSC Electric Supply Load	**510,194**	**533,603**	**488,645**	**465,210**	**483,078**	**530,062**	**563,388**	**525,942**	**497,190**	**474,079**	**453,460**	**462,147**	**5,986,998**
Yellowstone Park Load	**2,385**	**2,545**	**2,427**	**1,865**	**1,171**	**911**	**977**	**1,002**	**922**	**1,014**	**1,735**	**2,280**	**19,234**
Total Electric Supply Load	**512,578**	**536,148**	**491,072**	**467,075**	**484,248**	**530,972**	**564,365**	**526,945**	**498,113**	**475,093**	**455,195**	**464,427**	**6,006,232**
													-

NorthWestern Energy
Electric Utility
Deferred Electricity Supply Cost Account Balance
July 2012 - June 2013

Month	Monthly Collection	Collection to-date	Balance Remaining
Jul11-Jun12 under-collected balance as filed in D2012.5.49			**$ 11,496,428**
Rates effective 8/1/2012 in compliance with Interim Order No. 7219a.			
Prior Period Jul11-Jun12 True-up - Deferred:			
May12: Deferred - Estimated as filed in D2012.5.49		$ (1,598,737)	
May12: Deferred - Actual		$ (1,555,113)	$ 43,624
Jun12: Deferred - Estimated as filed in D2012.5.49		$ (1,755,397)	
Jun12: Deferred - Actual		$ (1,626,135)	$ 129,262
Prior Period Jul11-Jun12 True-up - Supply:			
May12: Revenue - Estimated as filed in D2012.5.49	$ 16,798,979		
May12: Revenue - Actual	$ 16,239,166	$ (559,813)	
May12: Expense - Estimated as filed in D2012.5.49	$ 20,617,849		
May12: Expense - Actual	$ 21,785,208	$ 1,167,359	$ 1,727,171
Jun12: Revenue - Estimated as filed in D2012.5.49	$ 18,535,496		
Jun12: Revenue - Actual	$ 17,131,675	$ (1,403,821)	
Jun12: Expense - Estimated as filed in D2012.5.49	$ 17,177,881		
Jun12: Expense - Actual	$ 17,690,292	$ 512,411	$ 1,916,232
Actual Jul11-Jun12 under-collected balance[1]			**$ 15,312,718**
			-
Deferred Jul12-Jun13 Monthly Activity[2]:			
July 2012	$ 1,911,087	$ 1,911,087	$ 13,401,630
August 2012	$ 383,254	$ 2,294,341	$ 13,018,377
September 2012	$ 1,092,388	$ 3,386,729	$ 11,925,988
October 2012	$ 946,625	$ 4,333,354	$ 10,979,363
November 2012	$ 961,494	$ 5,294,849	$ 10,017,869
December 2012	$ 1,078,367	$ 6,373,215	$ 8,939,502
January 2013	$ 1,200,713	$ 7,573,928	$ 7,738,789
February 2013	$ 1,110,621	$ 8,684,549	$ 6,628,169
March 2013	$ 1,035,866	$ 9,720,415	$ 5,592,303
April 2013 - Estimated	$ 980,617	$ 10,701,032	$ 4,611,685
May 2013 - Estimated	$ 877,138	$ 11,578,171	$ 3,734,547
June 2013 - Estimated	$ 960,865	$ 12,539,036	$ 2,773,682
		-	
Prior Period Jul11-Jun12 Electricity Supply Cost Ending Balance			**$ 2,773,682**
			-
Current Period Jul12-Jun13 Electricity Supply Cost Ending Balance (see page 2)			**$ (6,250,793)**
Total Electricity Supply Cost Balance Jul12-Jun13[3]			**$ (3,477,111)**
			-

[1]Source: Exhibit_(FVB-1)12-13, page 2, line 10.
[2]Source: Exhibit_(FVB-1)12-13, page 1, line 52.
[3]Source: Exhibit_(FVB-1)12-13, page 2, line 15.

NorthWestern Energy
Electric Utility
Electricity Supply Cost Account Balance
July 2012 - June 2013

Month		Supply Cost Revenue		Supply Cost Expense		Supply Cost Balance
July 2012	$	19,312,937	$	18,955,837	$	(357,100)
August 2012	$	21,177,061	$	20,785,383	$	(391,678)
September 2012	$	19,942,483	$	16,570,326	$	(3,372,158)
October 2012	$	17,385,184	$	17,519,951	$	134,767
November 2012	$	17,646,839	$	18,900,346	$	1,253,507
December 2012	$	19,906,999	$	19,693,223	$	(213,777)
January 2013	$	22,128,411	$	20,184,832	$	(1,943,579)
February 2013	$	20,326,143	$	17,562,815	$	(2,763,328)
March 2013	$	18,914,207	$	18,000,730	$	(913,477)
April 2013 - Estimated	$	18,080,343	$	17,878,643	$	(201,700)
May 2013 - Estimated	$	17,825,009	$	20,646,248	$	2,821,239
June 2013 - Estimated	$	19,523,917	$	19,220,408	$	(303,509)
Supply Cost Balance Jul12-Jun13	**$**	**232,169,533**	**$**	**225,918,740**	**$**	**(6,250,793)**
		-		-		-

Source:
Revenue: Exhibit_(FVB-1)12-13, page 1, line 17.
Expense: Exhibit_(FVB-1)12-13, page 1, line 50.

NorthWestern Energy
Electric Utility Derivation of Rates
Deferred Electricity Supply
Tracker Period July 2013 to June 2014

Customer Rate Class	Loss Factor	Jul13 to Jun14 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	Deferred Supply Cost Rate After Losses	Deferred Supply Cost Revenue Check
Residential	8.5100%	2,356,022,192	2,356,022,192	2,556,519,680	$ (0.000584)	$ (1,375,917)
Residential Employee	8.5100%	3,886,619	2,331,972	2,530,422	$ (0.000350)	$ (1,360)
GS 1 Secondary NonDemand	8.5100%	279,360,817	279,360,817	303,134,423	$ (0.000584)	$ (163,147)
GS 1 Secondary Demand	8.5100%	2,477,871,468	2,477,871,468	2,688,738,330	$ (0.000584)	$ (1,447,077)
GS 1 Primary NonDemand	5.5400%	563,318	563,318	594,526	$ (0.000568)	$ (320)
GS 1 Primary Demand	5.5400%	357,213,999	357,213,999	377,003,654	$ (0.000568)	$ (202,898)
General Service Substation	4.6300%	232,669,987	232,669,987	243,442,607	$ (0.000563)	$ (130,993)
General Service Transmission	4.0000%	135,701,068	135,701,068	141,129,111	$ (0.000560)	$ (75,993)
Irrigation	8.5100%	86,094,805	86,094,805	93,421,473	$ (0.000584)	$ (50,279)
Lighting	8.5100%	57,613,774	57,613,774	62,516,706	$ (0.000584)	$ (33,646)
		5,986,998,047	5,985,443,400	6,469,030,933	$ (0.000582)	$ (3,481,630)
YNP Contract		19,233,936			Rounding Adjustment	$ 4,519
Total Electric Supply Load		6,006,231,983				$ (3,477,111)
		6,006,232				

2012-13 Deferred Electricity Supply Cost Over-Collection	**$ (3,477,111)**
Total Deferred Electricity Supply Rate Before Losses	$ (0.000538)
Total Deferred Electricity Supply Rate After Losses	$ (0.000582)

NorthWestern Energy
Electric Utility
Deferred Electricty Supply Revenue ($000) Summary
Tracker Period July 2013 to June 2014

	Jul13 to Jun14 Supply Retail kWh Sales	Current Deferred Supply Rates[1] 8/1/2012	Current Deferred Supply Revenue	Proposed Deferred Supply Rates 7/1/2013	Proposed Deferred Supply Revenue	Revenue Diff Proposed vs Current
Residential						
Residential	2,356,022	$ 0.002133	$ 5,025	$ (0.000584)	$ (1,376)	$ (6,401)
Residential Employee	3,887	$ 0.001280	$ 5	$ (0.000350)	$ (1)	$ (6)
Total Residential			$ 5,030		$ (1,377)	$ (6,408)
General Service 1						
GS-1 Sec Non-Demand	279,361	$ 0.002134	$ 596	$ (0.000584)	$ (163)	$ (759)
GS-1 Sec Demand	2,477,871	$ 0.002134	$ 5,288	$ (0.000584)	$ (1,447)	$ (6,735)
GS-1 Pri Non-Demand	563	$ 0.002076	$ 1	$ (0.000568)	$ (0)	$ (1)
GS-1 Pri Demand	357,214	$ 0.002076	$ 742	$ (0.000568)	$ (203)	$ (944)
Total GS-1			$ 6,627		$ (1,813)	$ (8,440)
General Service 2						
GS-2 Substation	232,670	$ 0.002058	$ 479	$ (0.000563)	$ (131)	$ (610)
GS-2 Transmission	135,701	$ 0.002046	$ 278	$ (0.000560)	$ (76)	$ (354)
Total GS-2			$ 756		$ (207)	$ (963)
Irrigation						
Irrigation	86,095	$ 0.002134	$ 184	$ (0.000584)	$ (50)	$ (234)
Total Irrigation			$ 184		$ (50)	$ (234)
Lighting						
Lighting	57,614	$ 0.002134	$ 123	$ (0.000584)	$ (34)	$ (157)
Total Lighting			$ 123		$ (34)	$ (157)
Total Rate Schedule	**5,986,998**		**$ 12,720**		**$ (3,482)**	**$ (16,201.833)**
	-					

[1]Docket No. D2012.5.49, Interim Order No. 7219a in August 2012 Electric Supply monthly filing, effective 8/1/2012.

Northwestern Energy
Electric Utility Derivation of Rates
Electricity Supply Excluding Generation Assets - Prior to Cap Adjustment
Tracker Period July 2013 to June 2014

Customer Rate Class	Loss Factor	Jul13 to Jun14 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	Electricity Supply Rate After Losses	Electricity Supply Revenue Check
Residential	8.5100%	2,356,022,192	2,356,022,192	2,556,519,680	$ 0.040001	$ 94,243,244
Residential Employee	8.5100%	3,886,619	2,331,972	2,530,422	$ 0.024001	$ 93,283
GS 1 Secondary NonDemand	8.5100%	279,360,817	279,360,817	303,134,423	$ 0.040001	$ 11,174,712
GS 1 Secondary Demand	8.5100%	2,477,871,468	2,477,871,468	2,688,738,330	$ 0.040001	$ 99,117,337
GS 1 Primary NonDemand	5.5400%	563,318	563,318	594,526	$ 0.038906	$ 21,916
GS 1 Primary Demand	5.5400%	357,213,999	357,213,999	377,003,654	$ 0.038906	$ 13,897,768
General Service Substation	4.6300%	232,669,987	232,669,987	243,442,607	$ 0.038571	$ 8,974,314
General Service Transmission	4.0000%	135,701,068	135,701,068	141,129,111	$ 0.038339	$ 5,202,643
Irrigation	8.5100%	86,094,805	86,094,805	93,421,473	$ 0.040001	$ 3,443,878
Lighting	8.5100%	57,613,774	57,613,774	62,516,706	$ 0.040001	$ 2,304,609
		5,986,998,047	5,985,443,400	6,469,030,933	$ 0.039842	$ 238,473,704
YNP Contract		19,233,936			Rounding Adjustment	$ 3,328
Total Electricity Supply Load		6,006,231,983				$ 238,477,032

Electricity Supply Excluding Generation Assets Costs	$ 239,694,540
less: YNP Contract Revenues	$ (1,217,508)
Electricity Supply Excluding Generation Assets Rate Design Revenues	**$ 238,477,032**
Electricity Supply Cost Rate Before Losses	$ 0.036864
Electricity Supply Cost Rate After Losses	$ 0.039832

YNP Contract Load	19,233,936
YNP May13-Apr14 Contract Supply Rate	0.063300
YNP Supply Revenue	$ 1,217,508

NorthWestern Energy
Electric Utility Derivation of Rates
Electricity Supply Excluding Generation Assets Capped at Residential Increase
Revenues ($000)
Tracker Period July 2013 to June 2014

CAPPED RATES	Jul13 to Jun14 Supply Retail kWh Sales	Current Revenue	Proposed Rates	Proposed Revenue	$ Change	% Change	$ at Res Cap 0.86%	Capped $ Change	Capped % Change	Capped kWh Rates
Residential										
Residential	2,356,022	$ 93,440	$ 0.040001	$ 94,243	$ 803	0.86%	$ 94,243	$ 95,372	2.07%	$ 0.040480
Res Employee	3,887	$ 92	$ 0.024001	$ 93	$ 1	0.86%	$ 93	$ 94	2.07%	$ 0.024288
Total Residential	2,359,909	$ 93,532		$ 94,337	$ 804	0.86%	$ 94,337	$ 95,467	2.07%	
General Service 1										
GS1 Sec NonDmd	279,361	$ 10,023	$ 0.040001	$ 11,175	$ 1,152	11.49%	$ 10,109	$ 10,230	2.07%	$ 0.036620
GS1 Sec Dmd	2,477,871	$ 98,272	$ 0.040001	$ 99,117	$ 845	0.86%	$ 99,117	$ 100,305	2.07%	$ 0.040480
GS1 Prim NonDmd	563	$ 22	$ 0.038906	$ 22	$ 0	0.87%	$ 22	$ 22	2.07%	$ 0.039367
GS1 Prim Dmd	357,214	$ 12,581	$ 0.038906	$ 13,898	$ 1,316	10.46%	$ 12,690	$ 12,842	2.07%	$ 0.035949
Total GS-1	3,115,010	$ 120,898		$ 124,212	$ 3,313	2.74%	$ 121,938	$ 123,399	2.07%	
General Service 2										
GS2 Substation	232,670	$ 8,897	$ 0.038571	$ 8,974	$ 77	0.87%	$ 8,974	$ 9,081	2.07%	$ 0.039031
GS2 Transmission	135,701	$ 5,158	$ 0.038339	$ 5,203	$ 45	0.87%	$ 5,202	$ 5,265	2.07%	$ 0.038795
Total GS-2	368,371	$ 14,055		$ 14,177	$ 122	0.87%	$ 14,176	$ 14,346	2.07%	
Irrigation										
Irrigation	86,095	$ 3,089	$ 0.040001	$ 3,444	$ 355	11.49%	$ 3,115	$ 3,153	2.07%	$ 0.036620
Total Irrigation	86,095	$ 3,089		$ 3,444	$ 355	11.49%	$ 3,115	$ 3,153	2.07%	
Lighting										
Lighting	57,614	$ 2,067	$ 0.040001	$ 2,305	$ 238	11.49%	$ 2,085	$ 2,110	2.07%	$ 0.036620
Total Lighting	57,614	$ 2,067		$ 2,305	$ 238	11.49%	$ 2,085	$ 2,110	2.07%	
Total Rate Schedule	5,986,998	$ 233,642		$ 238,474	$ 4,832	2.07%	$ 235,651	$ 238,474		
	-							-		
Capped Rate Adjustment Factor							0.011979			

NorthWestern Energy
Electric Utility
Electricity Supply Excluding Generation Assets Revenue ($000) Summary
Tracker Period July 2013 to June 2014

	Jul13 to Jun14 Supply Retail kWh Sales		Current Rates[1] 6/1/2013		Current Supply Revenue		Proposed Rates 7/1/2013		Proposed Supply Revenue		Revenue Diff Proposed vs Current
Residential											
Residential	2,356,022	$	0.039660	$	93,440	$	0.040480	$	95,372	$	1,932
Residential Employee	3,887	$	0.023796	$	92	$	0.024288	$	94	$	2
Total Residential				$	93,532			$	95,466	$	1,934
General Service 1											
GS-1 Sec Non-Demand	279,361	$	0.035878	$	10,023	$	0.036620	$	10,230	$	207
GS-1 Sec Demand	2,477,871	$	0.039660	$	98,272	$	0.040480	$	100,304	$	2,032
GS-1 Pri Non-Demand	563	$	0.038569	$	22	$	0.039367	$	22	$	0
GS-1 Pri Demand	357,214	$	0.035221	$	12,581	$	0.035949	$	12,841	$	260
Total GS-1				$	120,898			$	123,398	$	2,500
General Service 2											
GS-2 Substation	232,670	$	0.038240	$	8,897	$	0.039031	$	9,081	$	184
GS-2 Transmission	135,701	$	0.038009	$	5,158	$	0.038795	$	5,265	$	107
Total GS-2				$	14,055			$	14,346	$	291
Irrigation											
Irrigation	86,095	$	0.035878	$	3,089	$	0.036620	$	3,153	$	64
Total Irrigation				$	3,089			$	3,153	$	64
Lighting											
Lighting	57,614	$	0.035878	$	2,067	$	0.036620	$	2,110	$	43
Total Lighting				$	2,067			$	2,110	$	43
Total Rate Schedule	**5,986,998**			**$**	**233,642**			**$**	**238,473**	**$**	**4,830.827**
	-										

[1]Appendix F in June 2013 Electric Supply monthly filing, effective June 1, 2013.

NorthWestern Energy
Electric Utility
Total Proposed Deferred Supply Rates
Effective July 1, 2013

	Deferred Electricity Supply Rates[1]	Deferred CU4 Rates[2]	Deferred DGGS Rates[3]	Total Deferred Supply Rates
Residential				
Residential	(0.000584)	(0.000314)	0.000772	(0.000126)
Residential Employee	(0.000350)	(0.000189)	0.000463	(0.000076)
Total Residential				
General Service 1				
GS-1 Sec Non-Demand	(0.000584)	(0.000314)	0.000772	(0.000126)
GS-1 Sec Demand	(0.000584)	(0.000314)	0.000772	(0.000126)
GS-1 Pri Non-Demand	(0.000568)	(0.000305)	0.000750	(0.000123)
GS-1 Pri Demand	(0.000568)	(0.000305)	0.000750	(0.000123)
Total GS-1				
General Service 2				
GS-2 Substation	(0.000563)	(0.000302)	0.000744	(0.000121)
GS-2 Transmission	(0.000560)	(0.000301)	0.000739	(0.000122)
Total GS-2				
Irrigation				
Irrigation	(0.000584)	(0.000314)	0.000772	(0.000126)
Total Irrigation				
Lighting				
Lighting	(0.000584)	(0.000314)	0.000772	(0.000126)
Total Lighting				
Average Billed Rate	**(0.000582)**	**(0.000313)**	**0.000769**	**(0.000894)**
Total Supply Rate	**(0.582)**	**(0.313)**	**0.769**	**(0.895)**

[1]Source: Exhibit_(CAH-2)13-14
[2]Source: Exhibit_(CAH-3)13-14
[3]Source: Exhibit_(CAH-4)13-14

NorthWestern Energy
Electric Utility
Total Deferred Supply Revenue ($000) Summary
Tracker Period July 2013 to June 2014

		Current Deferred Revenue				Proposed Deferred Revenue				Revenue
	Jul13 to Jun14 Supply Retail kWh Sales	Deferred Supply Revenue	Deferred CU4 Revenue	Deferred DGGS Revenue	Total Deferred Revenue	Deferred Supply Revenue	Deferred CU4 Revenue	Deferred DGGS Revenue	Total Deferred Revenue	Difference Proposed vs Current
Residential										
Residential	2,356,022	$ 5,025	$ (1,310)	$ (813)	$ 2,903	$ (1,376)	$ (740)	$ 1,819	$ (297)	$ (3,199)
Residential Employee	3,887	$ 5	$ (1)	$ (1)	$ 3	$ (1)	$ (1)	$ 2	$ (0)	$ (3)
Total Residential		$ 5,030	$ (1,311)	$ (814)	$ 2,905	$ (1,377)	$ (741)	$ 1,821	$ (297)	$ (3,203)
General Service 1										
GS-1 Sec Non Demand	279,361	$ 596	$ (155)	$ (96)	$ 344	$ (163)	$ (88)	$ 216	$ (35)	$ (380)
GS-1 Sec Demand	2,477,871	$ 5,288	$ (1,378)	$ (855)	$ 3,055	$ (1,447)	$ (778)	$ 1,913	$ (312)	$ (3,367)
GS-1 Pri Non Demand	563	$ 1	$ (0)	$ (0)	$ 1	$ (0)	$ (0)	$ 0	$ (0)	$ (1)
GS-1 Pri Demand	357,214	$ 742	$ (193)	$ (120)	$ 429	$ (203)	$ (109)	$ 268	$ (44)	$ (473)
Total GS-1		$ 6,627	$ (1,726)	$ (1,071)	$ 3,829	$ (1,813)	$ (975)	$ 2,397	$ (391)	$ (4,220)
General Service 2										
GS-2 Substation	232,670	$ 479	$ (125)	$ (77)	$ 277	$ (131)	$ (70)	$ 173	$ (28)	$ (305)
GS-2 Transmission	135,701	$ 278	$ (72)	$ (45)	$ 161	$ (76)	$ (41)	$ 100	$ (17)	$ (177)
Total GS-2		$ 756	$ (197)	$ (122)	$ 437	$ (207)	$ (111)	$ 273	$ (45)	$ (482)
Irrigation										
Irrigation	86,095	$ 184	$ (48)	$ (30)	$ 106	$ (50)	$ (27)	$ 66	$ (11)	$ (117)
Total Irrigation		$ 184	$ (48)	$ (30)	$ 106	$ (50)	$ (27)	$ 66	$ (11)	$ (117)
Lighting										
Lighting	57,614	$ 123	$ (32)	$ (20)	$ 71	$ (34)	$ (18)	$ 44	$ (7)	$ (78)
Total Lighting		$ 123	$ (32)	$ (20)	$ 71	$ (34)	$ (18)	$ 44	$ (7)	$ (78)
Total Rate Schedule	**5,986,998**	**$ 12,720**	**$ (3,314)**	**$ (2,057)**	**$ 7,349**	**$ (3,482)**	**$ (1,872)**	**$ 4,602**	**$ (751)**	**$ (8,100.251)**
	5,986,998	-	-	-	-	-	-	-	-	-

NorthWestern Energy
Electric Utility
Total Proposed Supply Rates
Effective July 1, 2013

	Proposed Electricity Supply Rates[1]	Colstrip Unit 4[2]		Dave Gates Gen Station[3]		Spion Kop[4]		Proposed Total Supply Rates
		Current Fixed Rates	Proposed Variable Rates	Current Fixed Rates	Proposed Variable Rates	Current Fixed Rates	Proposed Variable Rates	
Residential								
Residential	0.040480	0.012734	0.004334	0.004795	0.002049	0.001047	0.000014	0.065453
Residential Employee	0.024288	0.007640	0.002601	0.002877	0.001230	0.000628	0.000008	0.039272
Total Residential								
General Service 1								
GS-1 Sec Non-Demand	0.036620	0.012734	0.004334	0.004795	0.002049	0.001048	0.000014	0.061594
GS-1 Sec Demand	0.040480	0.012734	0.004334	0.004795	0.002049	0.001048	0.000014	0.065454
GS-1 Pri Non-Demand	0.039367	0.012385	0.004215	0.004664	0.001993	0.001020	0.000014	0.063658
GS-1 Pri Demand	0.035949	0.012385	0.004215	0.004664	0.001993	0.001020	0.000014	0.060240
Total GS-1								
General Service 2								
GS-2 Substation	0.039031	0.012278	0.004179	0.004624	0.001975	0.001011	0.000014	0.063112
GS-2 Transmission	0.038795	0.012204	0.004154	0.004596	0.001964	0.001005	0.000014	0.062732
Total GS-2								
Irrigation								
Irrigation	0.036620	0.012734	0.004334	0.004795	0.002049	0.001048	0.000014	0.061594
Total Irrigation								
Lighting								
Lighting	0.036620	0.012734	0.004334	0.004795	0.002049	0.001048	0.000014	0.061594
Total Lighting								
Average Billed Rate	**0.039832**	**0.012680**	**0.004316**	**0.004775**	**0.002040**	**0.001043**	**0.000014**	**0.064700**
Total Supply Rate	**39.832**		**16.996**		**6.815**		**1.057**	**64.700**

[1]Source: Exhibit_(CAH-2)13-14
[2]Source: Exhibit_(CAH-3)13-14
[3]Source: Exhibit_(CAH-4)13-14
[4]Source: Exhibit_(CAH-5)13-14

NorthWestern Energy
Electric Utility
Total Supply Revenue ($000) Summary by Rate Component
Tracker Period July 2013 to June 2014

	Total Supply Revenue Current Rate 6/1/2013	Proposed Supply Revenue							
		Electricity Supply Revenue	CU4 Fixed Revenue	CU4 Variable Revenue	DGGS Fixed Revenue	DGGS Variable Revenue	Spion Fixed Revenue	Spion Variable Revenue	Total Supply Revenue 7/1/2013
Residential									
Residential	$ 149,958	$ 95,372	$ 30,002	$ 10,211	$ 11,297	$ 4,827	$ 2,467	$ 33	$ 154,209
Residential Employee	$ 148	$ 94	$ 30	$ 10	$ 11	$ 5	$ 2	$ 0	$ 153
Total Residential	$ 150,107	$ 95,466	$ 30,031	$ 10,221	$ 11,308	$ 4,832	$ 2,469	$ 33	$ 154,361
General Service 1									
GS-1 Sec Non Demand	$ 16,725	$ 10,230	$ 3,557	$ 1,211	$ 1,340	$ 572	$ 293	$ 4	$ 17,207
GS-1 Sec Demand	$ 157,717	$ 100,304	$ 31,553	$ 10,739	$ 11,881	$ 5,077	$ 2,597	$ 35	$ 162,187
GS-1 Pri Non Demand	$ 35	$ 22	$ 7	$ 2	$ 3	$ 1	$ 1	$ 0	$ 36
GS-1 Pri Demand	$ 20,917	$ 12,841	$ 4,424	$ 1,506	$ 1,666	$ 712	$ 364	$ 5	$ 21,519
Total GS-1	$ 195,393	$ 123,398	$ 39,542	$ 13,458	$ 14,890	$ 6,363	$ 3,255	$ 44	$ 200,948
General Service 2									
GS-2 Substation	$ 14,279	$ 9,081	$ 2,857	$ 972	$ 1,076	$ 460	$ 235	$ 3	$ 14,684
GS-2 Transmission	$ 8,278	$ 5,265	$ 1,656	$ 564	$ 624	$ 267	$ 136	$ 2	$ 8,513
Total GS-2	$ 22,557	$ 14,346	$ 4,513	$ 1,536	$ 1,700	$ 726	$ 372	$ 5	$ 23,197
Irrigation									
Irrigation	$ 5,154	$ 3,153	$ 1,096	$ 373	$ 413	$ 176	$ 90	$ 1	$ 5,303
Total Irrigation	$ 5,154	$ 3,153	$ 1,096	$ 373	$ 413	$ 176	$ 90	$ 1	$ 5,303
Lighting									
Lighting	$ 3,449	$ 2,110	$ 734	$ 250	$ 276	$ 118	$ 60	$ 1	$ 3,549
Total Lighting	$ 3,449	$ 2,110	$ 734	$ 250	$ 276	$ 118	$ 60	$ 1	$ 3,549
Total Rate Schedule	$ 376,661	$ 238,473	$ 75,916	$ 25,838	$ 28,587	$ 12,215	$ 6,246	$ 84	$ 387,358
	-	-	-	-	-	-	-	-	-

NorthWestern Energy
Electric Utility
Total Supply Revenue ($000) Summary
Tracker Period July 2013 to June 2014

	Jul13 to Jun14 Supply Retail kWh Sales	Current Total Supply Rates[1] 6/1/2013	Current Total Supply Revenue	Proposed Total Supply Rates 7/1/2013	Proposed Total Supply Revenue	Revenue Difference Proposed vs Current	% Change
Residential							
Residential	2,356,022	0.063649	$ 149,958	0.065453	$ 154,209	$ 4,250	2.83%
Residential Employee	3,887	0.038189	$ 148	0.039272	$ 153	$ 4	2.84%
Total Residential			$ 150,107		$ 154,361	$ 4,254	
General Service 1							
GS-1 Sec Non-Demand	279,361	0.059868	$ 16,725	0.061594	$ 17,207	$ 482	2.88%
GS-1 Sec Demand	2,477,871	0.063650	$ 157,717	0.065454	$ 162,187	$ 4,470	2.83%
GS-1 Pri Non-Demand	563	0.061903	$ 35	0.063658	$ 36	$ 1	2.84%
GS-1 Pri Demand	357,214	0.058555	$ 20,917	0.060240	$ 21,519	$ 602	2.88%
Total GS-1			$ 195,393		$ 200,948	$ 5,555	
General Service 2							
GS-2 Substation	232,670	0.061372	$ 14,279	0.063112	$ 14,684	$ 405	2.84%
GS-2 Transmission	135,701	0.061001	$ 8,278	0.062732	$ 8,513	$ 235	2.84%
Total GS-2			$ 22,557		$ 23,197	$ 640	
Irrigation							
Irrigation	86,095	0.059868	$ 5,154	0.061594	$ 5,303	$ 149	2.88%
Total Irrigation			$ 5,154		$ 5,303	$ 149	
Lighting							
Lighting	57,614	0.059868	$ 3,449	0.061594	$ 3,549	$ 99	2.88%
Total Lighting			$ 3,449		$ 3,549	$ 99	
Total Rate Schedule	**5,986,998**		**$ 376,661**		**$ 387,358**	$ 10,697,410	2.84%
	-				-	-	
						-	

[1]Appendix F in June 2013 Electric Supply monthly filing, effective June 1, 2013.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.5.33
Annual CU4 True-up
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF FRANK V. BENNETT

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL COLSTRIP UNIT 4 ("CU4") TRUE-UP

TABLE OF CONTENTS

Witness Information

Q. Are you the same Frank V. Bennett who filed prefiled direct testimony in the Electricity Supply Tracker portion of this docket?

A. Yes.

Purpose of Testimony

Q. Please describe the purpose of this testimony.

A. In this testimony, I present the following information:

- The updated CU4 costs for the 12-month ended June 2013 true-up period with 9 months of actual numbers and 3 months of estimated numbers, and
- The forecast CU4 costs for the 12-month ended June 2014 true-up period.

Update to CU4 Values in the 2012/2013 True-up Period

Q. How has NorthWestern updated the CU4 generation that is reflected in the 2012/2013 electricity supply tracker?

A. NorthWestern has included the full rate-based volume of unit contingent energy associated with 222 MW of capacity from July 1, 2012 through June 30, 2013.

Q. How are the CU4 variable costs treated in the 2012/2013 true-up period?

A. The CU4 costs are treated the same as they were in NorthWestern's 2012 annual CU4 true-up filing. The variable CU4 cost of service includes fuel costs, incremental property taxes, and DSM lost revenues. These variable costs are tracked in a manner similar to the market-based supply costs. The CU4 variable cost was updated in January 2013 to reflect the CU4 property tax changes submitted in the 2013 Annual Property Tax Tracker filing.

Q. Have any adjustments been made to the CU4 fixed cost of service in the 2012/2013 or 2013/2014 true-up periods?

A. No. The CU4 fixed cost of service presented in this filing includes the costs which were approved in Docket No. D2008.6.69. They will remain unchanged until such time that an order is issued in a subsequent revenue requirement filing.

Q. Please summarize the 12-month ended June 2013 CU4 deferred account balance.

A. The June 2012 deferred account balance of $(5,239,576) over-collection shown on page 2 of Exhibit__(FVB-4 Rev)11-12 from Docket No. D2012.5.49 is the July 2012 beginning deferred account balance. With 9 months actual values and 3 months estimated values, the June 2013 estimated ending deferred account balance is a $(1,868,066) over-collection. Please refer to the Prefiled Direct Testimony of Cheryl A. Hansen - CU4 True-up for further discussion of the Deferred Account.

Q. Please summarize the 12-month ended June 2013 CU4 true-up period variable costs.

A. The CU4 true-up period is summarized in the following table (rounded from tracker values):

Beginning Deferred CU4		**Balance ($)**
Over-Collection		(5,239,576)

Variable Costs CU4		**Cost ($)**
Fuel Cost		20,918,131
Property Tax Adjustments		(345,094)
DSM Lost Revenue		2,957,541
DSM Lost Revenue Adjustment		46,435
Subtotal Variable CU4 Cost of Service:		23,577,012

Carrying Costs		(151,203)
Total Variable Costs		23,425,809

Variable Revenues CU4		**Revenue ($)**
Revenues		24,916,353
Prior Deferred Expense		(4,862,054)
Subtotal Revenues:		20,054,299

Ending Deferred CU4		**Balance ($)**
Over-Collection		(1,868,066)

Forecast of CU4 in the 2013/2014 True-up Period

Q. Please summarize the 12-month CU4 true-up period ending June 2014.

A. The June 2013 Deferred Account over-collection ending balance of $(1,868,066) as described above is the July 2013 beginning balance. July 2013 through June 2014 information is based on forecasted numbers. Please see Exhibit__(FVB-5)13-14 for supply volume and cost details of the 12-month forecast tracker period.

Q. Describe the changes within the CU4 variable Revenue and Expense categories for the 12-month ended June 2014 forecast true-up period.

A. The CU4 generation asset true-up variable cost revenue and expense details are reflected on page 2 of Exhibit__(FVB-5)13-14 under two main sections, Total Revenue and Total Variable Expenses. Total Net Revenue is estimated to be $23,971,491. This includes the current year revenue of $25,839,557 offset by the deferred balance carry forward of the $(1,868,066) over-collection from the prior true-up period as shown on Exhibit__(FVB-4)12-13. The 12-month forecast true-up estimates Total Variable CU4 Expenses of $25,839,557.

Q. Please provide a summary table of the 12-month ended June 2014 CU4 true-up period.

A. The CU4 true-up period is summarized in the following table (rounded from tracker values):

Beginning Deferred CU4		**Balance ($)**
Over-Collection		(1,868,066)

Variable Costs CU4		**Cost ($)**
Fuel Expense		22,511,264
Property Tax Adjustments		(243,944)
DSM Lost Revenue		3,653,224
DSM Lost Revenue Adjustment		0
Subtotal Variable CU4 Cost of Service:		25,920,544

Carrying Costs		(80,986)
Total Variable Costs		25,839,557

Variable Revenues CU4		**Revenue ($)**
Revenues		25,839,557
Prior Year Deferred		(1,868,066)
Subtotal Revenues:		23,971,491

Ending Deferred CU4		**Balance ($)**
Even Collection		0

Q. Does this conclude your Annual CU4 True-up testimony?

A. Yes, it does.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Colstrip Unit 4 Generation Asset Component**															
2				**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Total**
3				Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	
4	**Colstrip Unit 4 Fixed Cost Revenue Requirement – Per Final Order 6925f**															
5	Colstrip 4 Plant In Service															
6		Electric Generation Plant		$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$407,000,000
7		Accumulated Depreciation (Book Life 34 Yrs)		$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (11,970,588)
8		Deferred Income Taxes		$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (1,152,169)
9		Total Year End Rate-Base		$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$393,877,243
10																
11	Average Annual Rate-Base			$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$400,438,621
12																
13	Fixed Return (Avg Rate-Base * Cost of Capital)		8.25%	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 33,036,186
14																
15	Fixed Cost of Service															
16		Steam Power Generation Operation		$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 8,874,144
17		Purchase Power		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Administrative and General Expenses		$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 2,968,654
19		Depreciation		$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 11,970,588
20		Property Taxes		$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 2,431,458
21		Taxes Other than Income		$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 529,037
22		MCC/MPSC Taxes	0.45%	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 234,907
23		Deferred Income Taxes		$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 1,152,169
24		Current Income Taxes		$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 11,620,288
25		Miscellaneous Revenues (Rent)		$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (71,887)
26	Fixed Cost of Service			$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 39,709,358
27																
28	Total CU4 Fixed Cost Revenue Requirement			$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 72,745,544
29																
30																

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
31		**Colstrip Unit 4 Generation Asset Component**														
32				**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Total**
33				Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	
34		**Colstrip Unit 4 Variable Cost**														
35		Total Forecast Sales														
36		2011/12 Tracker Sales MWh		508,737	551,049	516,614	445,633	451,251	507,415	565,008	522,733	487,459	461,420	447,693	453,829	5,918,840
37		CU4 Cost		$ 4.6065	$ 4.6065	$ 4.6065	$ 4.6065	$ 4.6065	$ 4.6065	$ 4.2273	$ 4.2273	$ 4.2273	$ 4.2273	$ 4.2273	$ 4.2273	
38		Prior Year Deferred Expense		$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	$ (0.5034)	
39																
40		Colstrip Unit 4 Variable Cost Revenues														
41		NWE CU4 Revenues		$ 2,133,202	$ 2,310,332	$ 2,165,932	$ 1,867,332	$ 1,890,839	$ 2,127,334	$ 2,389,160	$ 2,209,849	$ 2,061,211	$ 1,950,118	$ 1,892,553	$ 1,918,492	$ 24,916,353
42																
43		Subtotal		$ 2,133,202	$ 2,310,332	$ 2,165,932	$ 1,867,332	$ 1,890,839	$ 2,127,334	$ 2,389,160	$ 2,209,849	$ 2,061,211	$ 1,950,118	$ 1,892,553	$ 1,918,492	$ 24,916,353
44		Prior Year(s) Deferred Expense		$ (2,114,471)	$ (102,653)	$ (286,082)	$ (246,638)	$ (249,743)	$ (280,983)	$ (312,894)	$ (289,408)	$ (269,945)	$ (255,391)	$ (225,378)	$ (228,467)	$ (4,862,054)
45		Total Revenue		$ 18,730	$ 2,207,678	$ 1,879,850	$ 1,620,694	$ 1,641,096	$ 1,846,351	$ 2,076,266	$ 1,920,441	$ 1,791,266	$ 1,694,726	$ 1,667,175	$ 1,690,025	$ 20,054,299
46																
47		Colstrip Unit 4 Fuel Cost		$ 2,331,300	$ 1,940,657	$ 1,846,658	$ 2,089,401	$ 1,454,490	$ 1,585,308	$ 1,921,861	$ 1,956,864	$ 2,026,734	$ 1,882,429	$ 941,215	$ 941,215	$ 20,918,131
48																
49		Incremental Property Tax Adjustment		$ (37,187)	$ (37,187)	$ (37,187)	$ (37,187)	$ (37,187)	$ (37,187)	$ (20,329)	$ (20,329)	$ (20,329)	$ (20,329)	$ (20,329)	$ (20,329)	$ (345,094)
50																
51		DSM Lost Revenue		$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 246,462	$ 2,957,541
52		DSM Lost Revenue Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 46,435	$ -	$ 46,435
53																
54		Subtotal Colstrip Unit 4 Variable Cost		$ 2,540,575	$ 2,149,932	$ 2,055,933	$ 2,298,676	$ 1,663,764	$ 1,794,582	$ 2,147,994	$ 2,182,997	$ 2,252,867	$ 2,108,562	$ 1,213,783	$ 1,167,348	$ 23,577,012
55																
56																
57		**Carrying Cost Expense**														
58		Carrying Costs	7.80%	$ (17,770)	$ (18,264)	$ (17,232)	$ (12,911)	$ (12,848)	$ (13,270)	$ (12,888)	$ (11,255)	$ (8,311)	$ (5,659)	$ (8,661)	$ (12,135)	$ (151,203)
59																
60		Total Variable CU4 Expenses		$ 2,522,805	$ 2,131,668	$ 2,038,701	$ 2,285,764	$ 1,650,917	$ 1,781,312	$ 2,135,106	$ 2,171,741	$ 2,244,557	$ 2,102,903	$ 1,205,122	$ 1,155,213	$ 23,425,809
61																
62		Deferred Cost Amortization (Under)/Over		$ (2,114,471)	$ (102,653)	$ (286,082)	$ (246,638)	$ (249,743)	$ (280,983)	$ (312,894)	$ (289,408)	$ (269,945)	$ (255,391)	$ (225,378)	$ (228,467)	$ (4,862,054)
63		Monthly Deferred Cost		$ (389,603)	$ 178,664	$ 127,231	$ (418,432)	$ 239,922	$ 346,022	$ 254,054	$ 38,108	$ (183,346)	$ (152,785)	$ 687,431	$ 763,279	$ 1,490,544
64		Cumulative Deferred Cost		$ (389,603)	$ (210,939)	$ (83,708)	$ (502,141)	$ (262,218)	$ 83,803	$ 337,857	$ 375,965	$ 192,619	$ 39,834	$ 727,265	$ 1,490,544	
65																
66		Variable Rate-Base Deferred														
67		Beginning Balance		$ (5,239,576)	$ (2,735,501)	$ (2,811,512)	$ (2,652,660)	$ (1,987,590)	$ (1,977,769)	$ (2,042,808)	$ (1,983,968)	$ (1,732,668)	$ (1,279,378)	$ (871,201)	$ (1,333,254)	
68		Monthly Deferred Cost		$ 2,504,074	$ (76,010)	$ 158,851	$ 665,070	$ 9,821	$ (65,039)	$ 58,840	$ 251,300	$ 453,290	$ 408,177	$ (462,053)	$ (534,812)	
69		Ending Balance Under/(Over)		$ (2,735,501)	$ (2,811,512)	$ (2,652,660)	$ (1,987,590)	$ (1,977,769)	$ (2,042,808)	$ (1,983,968)	$ (1,732,668)	$ (1,279,378)	$ (871,201)	$ (1,333,254)	$ (1,868,066)	
70																

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Colstrip Unit 4 Generation Asset Component**														
2			**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Total**
3			Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
4	**Colstrip Unit 4 Fixed Cost Revenue Requirement -- Per Final Order 6925f**														
5	Colstrip 4 Plant in Service														
6	Electric Generation Plant		$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$ 33,916,667	$407,000,000
7	Accumulated Depreciation (Book Life 34 Yrs)		$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (997,549)	$ (11,970,588)
8	Deferred Income Taxes		$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (96,014)	$ (1,152,169)
9	Total Year End Rate Base		$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$ 32,823,104	$393,877,243
10															
11	Average Annual Rate-Base		$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$ 33,369,885	$400,438,621
12															
13	Fixed Return (Avg Rate-Base * Cost of Capital)	8.25%	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 2,753,016	$ 33,036,186
14															
15	Fixed Cost of Service														
16	Steam Power Generation Operation		$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 739,512	$ 8,874,144
17	Purchase Power		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Administrative and General Expenses		$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 247,388	$ 2,968,654
19	Depreciation		$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 997,549	$ 11,970,588
20	Property Taxes		$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 202,622	$ 2,431,458
21	Taxes Other than Income		$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 44,086	$ 529,037
22	MCC/MPSC Taxes	0.45%	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 19,576	$ 234,907
23	Deferred Income Taxes		$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 96,014	$ 1,152,169
24	Current Income Taxes		$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 968,357	$ 11,620,288
25	Miscellaneous Revenues (Rent)		$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (5,991)	$ (71,887)
26	Fixed Cost of Service		$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 3,309,113	$ 39,709,358
27															
28	Total CU4 Fixed Cost Revenue Requirement		$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 6,062,129	$ 72,745,544
29															
30															

	A / B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
31	**Colstrip Unit 4 Generation Asset Component**														
32			**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Total**
33			Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
34	**Colstrip Unit 4 Variable Cost**														
35	Total Forecast Sales														
36	2011/12 Tracker Sales MWh		510,194	533,603	488,645	465,210	483,078	530,062	563,388	525,942	497,190	474,079	453,460	462,147	5,986,998
37	CU4 Cost		$ 4.3159	$ 4.3159	$ 4.3159	$ 4.3159	$ 4.3159	$ 4.3159	$ 4.3159	$ 4.3159	$ 4.3159	$ 4.3159	$ 4.3159	$ 4.3159	
38	Prior Year Deferred Expense		$ (0.3120)	$ (0.3120)	$ (0.3120)	$ (0.3120)	$ (0.3120)	$ (0.3120)	$ (0.3120)	$ (0.3120)	$ (0.3120)	$ (0.3120)	$ (0.3120)	$ (0.3120)	
39															
40	Colstrip Unit 4 Variable Cost Revenues														
41	NWE CU4 Revenues		$ 2,201,967	$ 2,303,002	$ 2,108,967	$ 2,007,821	$ 2,084,936	$ 2,287,717	$ 2,431,550	$ 2,269,939	$ 2,145,846	$ 2,046,100	$ 1,957,111	$ 1,994,601	$ 25,839,557
42															
43	Subtotal		$ 2,201,967	$ 2,303,002	$ 2,108,967	$ 2,007,821	$ 2,084,936	$ 2,287,717	$ 2,431,550	$ 2,269,939	$ 2,145,846	$ 2,046,100	$ 1,957,111	$ 1,994,601	$ 25,839,557
44	Prior Year(s) Deferred Expense		$ (159,191)	$ (166,495)	$ (152,467)	$ (145,155)	$ (150,730)	$ (165,390)	$ (175,788)	$ (164,105)	$ (155,134)	$ (147,922)	$ (141,489)	$ (144,199)	$ (1,868,066)
45	Total Revenue		$ 2,042,777	$ 2,136,507	$ 1,956,500	$ 1,862,666	$ 1,934,206	$ 2,122,327	$ 2,255,762	$ 2,105,834	$ 1,990,712	$ 1,898,178	$ 1,815,622	$ 1,850,401	$ 23,971,491
46															
47	Colstrip Unit 4 Fuel Cost		$ 1,875,939	$ 1,875,939	$ 1,875,939	$ 1,875,939	$ 1,875,939	$ 1,875,939	$ 1,875,939	$ 1,875,939	$ 1,875,939	$ 1,875,939	$ 1,875,939	$ 1,875,939	$ 22,511,264
48															
49	Incremental Property Tax Adjustment		$ (20,329)	$ (20,329)	$ (20,329)	$ (20,329)	$ (20,329)	$ (20,329)	$ (20,329)	$ (20,329)	$ (20,329)	$ (20,329)	$ (20,329)	$ (20,329)	$ (243,944)
50															
51	DSM Lost Revenue		$ 304,435	$ 304,435	$ 304,435	$ 304,435	$ 304,435	$ 304,435	$ 304,435	$ 304,435	$ 304,435	$ 304,435	$ 304,435	$ 304,435	$ 3,653,224
52	DSM Lost Revenue Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53															
54	Subtotal Colstrip Unit 4 Variable Cost		$ 2,160,045	$ 2,160,045	$ 2,160,045	$ 2,160,045	$ 2,160,045	$ 2,160,045	$ 2,160,045	$ 2,160,045	$ 2,160,045	$ 2,160,045	$ 2,160,045	$ 2,160,045	$ 25,920,544
55															
56															
57	**Carrying Cost Expense**														
58	Carrying Costs	7.80%	$ (11,448)	$ (11,368)	$ (10,112)	$ (8,234)	$ (6,811)	$ (6,609)	$ (7,278)	$ (6,971)	$ (5,909)	$ (4,236)	$ (2,011)	$ 0	$ (80,986)
59															
60	Total Variable CU4 Expenses		$ 2,148,598	$ 2,148,677	$ 2,149,933	$ 2,151,812	$ 2,153,234	$ 2,153,437	$ 2,152,768	$ 2,153,074	$ 2,154,136	$ 2,155,810	$ 2,158,034	$ 2,160,045	$ 25,839,557
61															
62	Deferred Cost Amortization (Under)/Over		$ (159,191)	$ (166,495)	$ (152,467)	$ (145,155)	$ (150,730)	$ (165,390)	$ (175,788)	$ (164,105)	$ (155,134)	$ (147,922)	$ (141,489)	$ (144,199)	$ (1,868,066)
63	Monthly Deferred Cost		$ 53,370	$ 154,326	$ (40,966)	$ (143,991)	$ (68,298)	$ 134,281	$ 278,783	$ 116,865	$ (8,290)	$ (109,710)	$ (200,923)	$ (165,445)	$ (0)
64	Cumulative Deferred Cost		$ 53,370	$ 207,695	$ 166,729	$ 22,738	$ (45,561)	$ 88,720	$ 367,503	$ 484,367	$ 476,077	$ 366,368	$ 165,445	$ (0)	
65															
66	Variable Rate-Base Deferred														
67	Beginning Balance		$ (1,868,066)	$ (1,762,245)	$ (1,750,074)	$ (1,556,641)	$ (1,267,495)	$ (1,048,467)	$ (1,017,357)	$ (1,120,351)	$ (1,073,111)	$ (909,688)	$ (652,056)	$ (309,644)	
68	Monthly Deferred Cost		$ 105,821	$ 12,170	$ 193,433	$ 289,146	$ 219,028	$ 31,109	$ (102,994)	$ 47,240	$ 163,424	$ 257,632	$ 342,412	$ 309,644	
69	Ending Balance Under/(Over)		$ (1,762,245)	$ (1,750,074)	$ (1,556,641)	$ (1,267,495)	$ (1,048,467)	$ (1,017,357)	$ (1,120,351)	$ (1,073,111)	$ (909,688)	$ (652,056)	$ (309,644)	$ 0	
70															

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.5.33
Annual CU4 True-up
NorthWestern Energy

PREFILED DIRECT TESTIMONY
OF CHERYL A. HANSEN
ON BEHALF OF NORTHWESTERN ENERGY
ANNUAL COLSTRIP UNIT 4 ("CU4") TRUE-UP

TABLE OF CONTENTS

Witness Information

Q. Are you the same Cheryl A. Hansen who filed prefiled direct testimony in the Electricity Supply Tracker portion of this docket?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your Annual CU4 True-up testimony?

A. This testimony:

1. Presents the derivation of proposed deferred CU4 variable rates resulting from the over/under-collection reflected in both the 2011-2012 true-up period and the 2012-2013 true-up period;
2. Presents the derivation of proposed CU4 variable rates for the forecasted 2013-2014 true-up period; and
3. Discusses the overall total supply rates incorporating all individual rate components.

Derivation of Proposed Deferred CU4 Variable Rates

Q. What is the CU4 variable cost account balance for the 12-month period ending June 2013?

A. The CU4 variable cost account balance for the 12-month period ending June 2013 is an over-collection of $(1,868,066) as presented on page 1 of Exhibit__(CAH-3)13-14. As discussed below, this includes the prior period balance for the 2011-2012 true-up period and the current period balance for the 2012-2013 true-up period.

Q. Describe the status of the deferred CU4 variable cost account balance associated with the 2011-2012 true-up period.

A. In the annual filing submitted on May 31, 2012, the net deferred account balance for the 2011-2012 true-up period was shown as an over-collection of $(2,993,971). This amount becomes the starting balance in this filing. Added to this balance is the prior period true-up for the 2 months of estimated data included in the May 2012 filing. Page 1 of Exhibit__(CAH-3)13-14 shows the true-up of the estimated months of May and June 2012 with actual data for these months. The resulting actual ending balance of $(5,239,576) is the deferred account beginning balance for the 2012-2013 true-up period. This balance is then combined with the current year deferred monthly activity shown on Exhibit__(CAH-3)13-14, page 1, resulting in a net over-collected balance of $(377,522) for the 2011-2012 true-up period. The months of April, May and June 2013 are estimated and will be trued-up in the next annual filing.

Q. Describe the CU4 variable cost account balance associated with the 2012-2013 true-up period.

A. Page 2 of Exhibit__(CAH-3)13-14 shows the monthly detail of the difference between the CU4 variable cost revenues and expenses for the

2012-2013 true-up period, resulting in an over-collected amount of $(1,490,544). The months of April, May and June 2013 are estimated and will be trued-up in the next annual filing.

Q. What is the total deferred CU4 variable cost account adjustment proposed for amortization in this filing?

A. The total deferred CU4 variable cost account adjustment proposed in this filing is an over-collection of $(1,868,066) shown below and on page 1, line 56 of Exhibit__(CAH-3)13-14.

Total Deferred CU4 Variable Cost Account Balance

2011-2012 Prior Period CU4 Variable Account Balance	$(377,522)
2012-2013 Current Period CU4 Variable Account Balance	$(1,490,544)
	$(1,868,066)

Derivation of the deferred CU4 variable rates is shown on Exhibit__(CAH-3)13-14, page 3 with the resulting rates and revenues shown on page 4.

Derivation of Proposed CU4 Variable Rates

Q. Please describe the process used by NorthWestern to derive the proposed 2013-2014 forecasted CU4 variable rates in this filing.

A. The rate design methodology used in this filing to derive the proposed 2013-2014 forecasted CU4 variable rates is the same as that presented in previous CU4 filings. All forecasted costs are from Exhibit__(FVB-5)13-14 of the Prefiled Direct Testimony of Frank V. Bennett and are discussed therein.

Derivation of the CU4 variable rates is shown on Exhibit__(CAH-3)13-14, page 5. The total CU4 variable cost of $25,839,557 is the sum of forecasted fuel costs, incremental property taxes, DSM Lost Revenues, and carrying costs from Exhibit__(FVB-5)13-14. This sum is the amount used to derive the CU4 variable rates. The forecasted loads used in the derivation are from Exhibit__(CAH-1)13-14. The resulting rates are the CU4 variable rates proposed in this filing.

Q. Please describe the 2013-2014 CU4 fixed rates included in this filing.

A. The CU4 fixed cost of service rate component presented in this filing remains unchanged and will not change until an order is issued in any subsequent revenue requirement filing that deals with CU4.

Page 6 of Exhibit__(CAH-3)13-14 reflects the CU4 fixed and variable rates and revenues in summarized format.

Proposed Total Deferred Supply and Total Supply Rates

Q. Please describe the process used by NorthWestern to derive the total 2013-2014 deferred supply rates proposed in this filing.

A. The total deferred supply rate includes three separate rate components – a deferred electricity supply rate, a deferred CU4 variable rate, and a deferred Dave Gates Generating Station ("DGGS") variable rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(CAH-6)13-14, page 1.

Q. Please describe the process used by NorthWestern to derive the total 2013-2014 supply rates proposed in this filing.

A. The total electric supply rate currently includes several separate rate components – an electricity supply tracker rate, a CU4 fixed cost of service rate, a CU4 variable rate, a DGGS fixed cost of service rate, a DGGS variable rate, a Spion Kop Wind Generation Asset ("Spion") fixed cost of service rate, and a Spion variable rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(CAH-6)13-14, page 3.

Q. Does this conclude your Annual CU4 True-up testimony?

A. Yes, it does.

NorthWestern Energy
Electric Utility
Deferred CU4 Variable Cost Account Balance
July 2012 - June 2013

Month	Monthly Collection	Collection to-date	Balance Remaining
Jul11-Jun12 over-collected balance as filed in D2012.5.49			**$ (2,993,971)**
Rates effective 8/1/2012 in compliance with Interim Order No. 7219a.			
<u>Prior Period Jul11-Jun12 True-up - Deferred:</u>			
May12: Deferred - Estimated as filed in D2012.5.49		$ 1,888,673	
May12: Deferred - Actual		$ 1,836,975	$ (51,698)
Jun12: Deferred - Estimated as filed in D2012.5.49		$ 2,073,744	
Jun12: Deferred - Actual		$ 1,920,868	$ (152,876)
<u>Prior Period Jul11-Jun12 True-up - Variable:</u>			
May12: Revenue - Estimated as filed in D2012.5.49	$ 1,707,667		
May12: Revenue - Actual	$ 1,723,783	$ 16,116	
May12: Expense - Estimated as filed in D2012.5.49	$ 4,065,604		
May12: Expense - Actual	$ 2,842,227	$ (1,223,377)	$ (1,239,492)
Jun12: Revenue - Estimated as filed in D2012.5.49	$ 1,875,001		
Jun12: Revenue - Actual	$ 1,802,510	$ (72,491)	
Jun12: Expense - Estimated as filed in D2012.5.49	$ 2,089,947		
Jun12: Expense - Actual	$ 1,215,918	$ (874,030)	$ (801,539)
Actual Jul11-Jun12 over-collected balance[1]			**$ (5,239,576)**
			-
<u>Deferred Jul12-Jun13 Monthly Activity[2]:</u>			
July 2012	$ (2,114,471)	$ (2,114,471)	$ (3,125,104)
August 2012	$ (102,653)	$ (2,217,125)	$ (3,022,451)
September 2012	$ (286,082)	$ (2,503,207)	$ (2,736,369)
October 2012	$ (246,638)	$ (2,749,845)	$ (2,489,731)
November 2012	$ (249,743)	$ (2,999,588)	$ (2,239,988)
December 2012	$ (280,983)	$ (3,280,571)	$ (1,959,005)
January 2013	$ (312,894)	$ (3,593,465)	$ (1,646,111)
February 2013	$ (289,408)	$ (3,882,873)	$ (1,356,703)
March 2013	$ (269,945)	$ (4,152,817)	$ (1,086,759)
April 2013 - Estimated	$ (255,391)	$ (4,408,208)	$ (831,367)
May 2013 - Estimated	$ (225,378)	$ (4,633,587)	$ (605,989)
June 2013 - Estimated	$ (228,467)	$ (4,862,054)	$ (377,522)
		-	
Prior Period Jul11-Jun12 CU4 Variable Cost Ending Balance			**$ (377,522)**
Current Period Jul12-Jun13 CU4 Variable Cost Ending Balance (see page 2)			**$ (1,490,544)**
Total CU4 Variable Cost Ending Balance Jul12-Jun13[3]			**$ (1,868,066)**
			-

[1]Source: Exhibit__(FVB-4)12-13, page 2, line 67, col D.
[2]Source: Exhibit__(FVB-4)12-13, page 2, line 62.
[3]Source: Exhibit__(FVB-4)12-13, page 2, line 69, col O.

NorthWestern Energy
Electric Utility
CU4 Variable Cost Account Balance
July 2012 - June 2013

Month		CU4 Variable Cost Revenue		CU4 Variable Cost Expense		CU4 Variable Cost Balance
July 2012	$	2,133,202	$	2,522,805	$	389,603
August 2012	$	2,310,332	$	2,131,668	$	(178,664)
September 2012	$	2,165,932	$	2,038,701	$	(127,231)
October 2012	$	1,867,332	$	2,285,764	$	418,432
November 2012	$	1,890,839	$	1,650,917	$	(239,922)
December 2012	$	2,127,334	$	1,781,312	$	(346,022)
January 2013	$	2,389,160	$	2,135,106	$	(254,054)
February 2013	$	2,209,849	$	2,171,741	$	(38,108)
March 2013	$	2,061,211	$	2,244,557	$	183,346
April 2013 - Estimated	$	1,950,118	$	2,102,903	$	152,785
May 2013 - Estimated	$	1,892,553	$	1,205,122	$	(687,431)
June 2013 - Estimated	$	1,918,492	$	1,155,213	$	(763,279)
CU4 Variable Balance Jul12-Jun13	**$**	**24,916,353**	**$**	**23,425,809**	**$**	**(1,490,544)**
		-		-		-

Source:
Revenue: Exhibit__(FVB-4)12-13, page 2, line 43.
Expense: Exhibit__(FVB-4)12-13, page 2, line 60.

Northwestern Energy
Electric Utility Derivation of Rates
Deferred CU4 Variable
Tracker Period July 2013 to June 2014

Customer Rate Class	Loss Factor	Jul13 to Jun14 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	Deferred CU4 Variable Rate After Losses	Deferred CU4 Variable Revenue Check
Residential	8.5100%	2,356,022,192	2,356,022,192	2,556,519,680	$ (0.000314)	$ (739,791)
Residential Employee	8.5100%	3,886,619	2,331,972	2,530,422	$ (0.000189)	$ (735)
GS 1 Secondary NonDemand	8.5100%	279,360,817	279,360,817	303,134,423	$ (0.000314)	$ (87,719)
GS 1 Secondary Demand	8.5100%	2,477,871,468	2,477,871,468	2,688,738,330	$ (0.000314)	$ (778,052)
GS 1 Primary NonDemand	5.5400%	563,318	563,318	594,526	$ (0.000305)	$ (172)
GS 1 Primary Demand	5.5400%	357,213,999	357,213,999	377,003,654	$ (0.000305)	$ (108,950)
General Service Substation	4.6300%	232,669,987	232,669,987	243,442,607	$ (0.000302)	$ (70,266)
General Service Transmission	4.0000%	135,701,068	135,701,068	141,129,111	$ (0.000301)	$ (40,846)
Irrigation	8.5100%	86,094,805	86,094,805	93,421,473	$ (0.000314)	$ (27,034)
Lighting	8.5100%	57,613,774	57,613,774	62,516,706	$ (0.000314)	$ (18,091)
		5,986,998,047	5,985,443,400	6,469,030,933	$ (0.000313)	$ (1,871,655)
YNP Contract		19,233,936			Rounding Adjustment	$ 3,590
Total Supply Load		6,006,231,983				$ (1,868,066)
		6,006,232				

2012-13 Deferred CU4 Variable Cost Over-Collection $ (1,868,066)

Total Deferred CU4 Variable Rate Before Losses $ (0.000289)
Total Deferred CU4 Variable Rate After Losses $ (0.000313)

NorthWestern Energy
Electric Utility
Deferred CU4 Variable Revenue ($000) Summary
Tracker Period July 2013 to June 2014

	Jul13 to Jun14 Supply Retail kWh Sales	Current Deferred CU4 Rates[1]	Current Deferred CU4 Revenue	Proposed Deferred CU4 Rates 7/1/2013	Proposed Deferred CU4 Revenue	Revenue Diff Proposed vs Current
Residential						
Residential	2,356,022	$ (0.000556)	$ (1,310)	$ (0.000314)	$ (740)	$ 570
Residential Employee	3,887	$ (0.000334)	$ (1)	$ (0.000189)	$ (1)	$ 1
Total Residential			$ (1,311)		$ (741)	$ 571
General Service 1						
GS-1 Sec Non Demand	279,361	$ (0.000556)	$ (155)	$ (0.000314)	$ (88)	$ 68
GS-1 Sec Demand	2,477,871	$ (0.000556)	$ (1,378)	$ (0.000314)	$ (778)	$ 600
GS-1 Pri Non Demand	563	$ (0.000540)	$ (0)	$ (0.000305)	$ (0)	$ 0
GS-1 Pri Demand	357,214	$ (0.000540)	$ (193)	$ (0.000305)	$ (109)	$ 84
Total GS-1			$ (1,726)		$ (975)	$ 751
General Service 2						
GS-2 Substation	232,670	$ (0.000536)	$ (125)	$ (0.000302)	$ (70)	$ 54
GS-2 Transmission	135,701	$ (0.000532)	$ (72)	$ (0.000301)	$ (41)	$ 31
Total GS-2			$ (197)		$ (111)	$ 86
Irrigation						
Irrigation	86,095	$ (0.000556)	$ (48)	$ (0.000314)	$ (27)	$ 21
Total Irrigation			$ (48)		$ (27)	$ 21
Lighting						
Lighting	57,614	$ (0.000556)	# $ (32)	$ (0.000314)	$ (18)	$ 14
Total Lighting			$ (32)		$ (18)	$ 14
Total Rate Schedule	**5,986,998**		**$ (3,314)**		**$ (1,872)**	**$ 1,442.618**
	-				-	

[1]Docket No. D2012.5.49, Interim Order No. 7219a in August 2012 Electric Supply monthly filing, effective 8/1/2012.

Northwestern Energy
Electric Utility Derivation of Rates
CU4 Variable Cost of Service
Tracker Period July 2013 to June 2014

Customer Rate Class	**Loss Factor**	**Jul13 to Jun14 Supply Retail kWh Sales**	**Sales Adjusted for Employee Discount**	**Sales Weighted by Losses**	**CU4 Variable After Losses kWh Charges**	**CU4 Variable Revenue/Cost Check**
Residential	8.5100%	2,356,022,192	2,356,022,192	2,556,519,680	$ 0.004334	$ 10,211,000
Residential Employee	8.5100%	3,886,619	2,331,972	2,530,422	$ 0.002601	$ 10,109
GS 1 Secondary NonDemand	8.5100%	279,360,817	279,360,817	303,134,423	$ 0.004334	$ 1,210,750
GS 1 Secondary Demand	8.5100%	2,477,871,468	2,477,871,468	2,688,738,330	$ 0.004334	$ 10,739,095
GS 1 Primary NonDemand	5.5400%	563,318	563,318	594,526	$ 0.004215	$ 2,374
GS 1 Primary Demand	5.5400%	357,213,999	357,213,999	377,003,654	$ 0.004215	$ 1,505,657
General Service Substation	4.6300%	232,669,987	232,669,987	243,442,607	$ 0.004179	$ 972,328
General Service Transmission	4.0000%	135,701,068	135,701,068	141,129,111	$ 0.004154	$ 563,702
Irrigation	8.5100%	86,094,805	86,094,805	93,421,473	$ 0.004334	$ 373,135
Lighting	8.5100%	57,613,774	57,613,774	62,516,706	$ 0.004334	$ 249,698
		5,986,998,047	5,985,443,400	6,469,030,933	$ 0.004317	$ 25,837,848
YNP Contract		19,233,936			Rounding Adjustment	$ 1,709
Total Supply Load		6,006,231,983				$ 25,839,557
		-				

2013-14 Colstrip Unit 4 Variable Cost of Service $ 25,839,557

Total CU4 Variable COS Rate Before Losses $ 0.003994
Total CU4 Variable COS Rate After Losses $ 0.004316

NorthWestern Energy
Electric Utility
Total CU4 Revenue ($000) Summary
Tracker Period July 2013 to June 2014

		CU4 Fixed		CU4 Variable				
	Jul13 to Jun14 Supply Retail kWh Sales	**Current Rates[1]**	**Current Rate Revenue**	**Current Rates[2]**	**Current Rate Revenue**	**Proposed Rates 7/1/2013**	**Proposed Rate Revenue**	**Revenue Diff Proposed vs Current**
Residential								
Residential	2,356,022	0.012734	$ 30,002	0.004245	$ 10,001	0.004334	$ 10,211	$ 210
Residential Employee	3,887	0.007640	$ 30	0.002547	$ 10	0.002601	$ 10	$ 0
Total Residential			$ 30,031		$ 10,011		$ 10,221	$ 210
General Service 1								
GS-1 Sec Non Demand	279,361	0.012734	$ 3,557	0.004245	$ 1,186	0.004334	$ 1,211	$ 25
GS-1 Sec Demand	2,477,871	0.012734	$ 31,553	0.004245	$ 10,519	0.004334	$ 10,739	$ 221
GS-1 Pri Non Demand	563	0.012385	$ 7	0.004129	$ 2	0.004215	$ 2	$ 0
GS-1 Pri Demand	357,214	0.012385	$ 4,424	0.004129	$ 1,475	0.004215	$ 1,506	$ 31
Total GS-1			$ 39,542		$ 13,182		$ 13,458	$ 276
General Service 2								
GS-2 Substation	232,670	0.012278	$ 2,857	0.004093	$ 952	0.004179	$ 972	$ 20
GS-2 Transmission	135,701	0.012204	$ 1,656	0.004068	$ 552	0.004154	$ 564	$ 12
Total GS-2			$ 4,513		$ 1,504		$ 1,536	$ 32
Irrigation								
Irrigation	86,095	0.012734	$ 1,096	0.004245	$ 365	0.004334	$ 373	$ 8
Total Irrigation			$ 1,096		$ 365		$ 373	$ 8
Lighting								
Lighting	57,614	0.012734	$ 734	0.004245	$ 245	0.004334	$ 250	$ 5
Total Lighting			$ 734		$ 245		$ 250	$ 5
Total Rate Schedule	**5,986,998**		**$ 75,916**		**$ 25,307**		**$ 25,838**	**$ 530.528**
	-						-	

[1]CU4 Fixed Rates approved in Docket No. D2010.5.50 Order No. 7093c, effective 4/1/2010.
[2]CU4 Variable Rates updated for property taxes in January 2013 Electric Supply monthly filing, effective 1/1/2013.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.5.33
Annual DGGS True-up
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF FRANK V. BENNETT

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL DAVE GATES GENERATING STATION ("DGGS") TRUE-UP

TABLE OF CONTENTS

Witness Information

Q. Are you the same Frank V. Bennett who filed prefiled direct testimony in the Electricity Supply Tracker portion of this docket?

A. Yes.

Purpose of Testimony

Q. Please describe this portion of your testimony.

A. In this testimony, I present the following information:

- The updated DGGS costs for the 12-month ended June 2013 true-up period with 9 months of actual numbers and 3 months of estimated numbers, and
- The forecast DGGS costs for the 12-month ended June 2014 true-up period.

Update to DGGS Values in the 2012/2013 True-up Period

Q. Does NorthWestern continue to utilize 7 MW of generation from DGGS within the 2012/2013 electric supply tracker?

A. Yes, NorthWestern includes the contribution of 7 MW of base load energy from the DGGS asset in the Electricity Supply Tracker.

Q. How are the DGGS variable costs of service treated in the 2012/2013 true-up period?

A. The DGGS costs are treated the same as they were in NorthWestern's 2012 annual true-up filing. The variable DGGS cost of service includes 9 months of actual values and 3 months of estimated information. The variable cost of service on page 2 of Exhibit__(FVB-6)12-13 includes fuel cost offset by costs allocated to choice customers and net revenue credits to derive the variable DGGS costs. These variable costs are tracked in a manner similar to the market-based supply costs. In addition, the DGGS variable cost was updated in January 2013 to reflect the DGGS property tax changes submitted in the 2013 Annual Property Tax Tracker filing.

Q. Have any adjustments been made to the DGGS fixed cost of service in the 2012/2013 or 2013/2014 true-up periods?

A. No. The DGGS fixed cost of service and associated fixed cost rates presented in this filing are the same as approved in Docket No. D2008.8.95, Order No. 6943e. The fixed costs will remain unchanged until such time that an order is issued in a subsequent revenue requirement filing.

Q. Please summarize the 12-month ended June 2013 DGGS deferred account balance.

A. The June 2012 deferred account balance of $755,103 under-collection shown on page 2 of Exhibit__(FVB-6 Rev)11-12 from Docket No. D2012.5.49 is the July 2012 beginning deferred balance. With 9 months of actual values and 3 months of estimated values, the June 2013 ending deferred account balance is a $4,598,342 under-collection. Please refer to the Prefiled Direct Testimony of Cheryl A. Hansen – Annual DGGS True-up for further discussion of the Deferred Account.

Q. Please summarize the 12-month ended June 2013 DGGS true-up period variable costs.

A. The DGGS true-up period is summarized in the following table:

Beginning Deferred DGGS		**Balance ($)**
Under-Collection		755,103

Variable Costs DGGS		**Cost ($)**
Fuel Cost		17,600,925
Fuel Adjustment		0
Less Energy Supply 7 MW		(1,567,725)
Less Transmission Service @ 20%		(3,206,640)
Energy Supply 7 MW		1,567,725
Reg. Contract Capacity		0
Reg. Contract Energy		0
Less Transmission Service @ 20%		0
DGGS – Fuel Cost Allocation:		14,394,285

Revenue Credits 27 MW		(6,705,833)
Less Transmission Service @ 20%		1,341,167
Reg. Contract Revenue Credit		0
Less Transmission Service @ 20%		0
DGGS – Revenue Credit Allocation:		(5,364,666)

Incremental Property Tax Adjustment		335,736
DSM Lost Revenue		539,139
DSM Lost Revenue Adjustment		69,822
Subtotal DGGS Variable Cost Allocation		9,302,844

Carrying Cost		236,264
Total DGGS Variable Cost Allocation		$ 9,539,107

Variable Revenues DGGS		**Revenue ($)**
Revenues		5,695,868

Ending Deferred DGGS		**Balance ($)**
Under-Collection		4,598,342

Forecast of DGGS in the 2013/2014 True-up Period

Q. Please summarize the 12-month DGGS true-up period ending June 2014.

A. The June 2013 Deferred Account under-collection ending balance of $4,598,342 as described above is the July 2013 beginning balance. July 2013 through June 2014 information is based on forecast numbers. Please see Exhibit__(FVB-7)13-14 for supply volume and cost details of the 12-month forecast tracking period.

Q. Describe the changes within the DGGS variable Revenue and Cost categories for the 12-month ended June 2014 forecast true-up period.

A. The DGGS generation asset variable cost revenue and expense details are reflected on page 2 of Exhibit__(FVB-7)13-14 under two main sections: Total Revenue and Total Variable Cost Allocation. Total Revenue is estimated to be $16,810,873. The 12-month forecast true-up period estimates a Total DGGS Variable Cost Allocation of $12,212,532.

Q. Please provide a summary table of the 12-month ended June 2014 DGGS true-up period.

A. The DGGS true-up period is summarized in the following table:

Beginning Deferred DGGS		**Balance ($)**
Under-Collection		4,598,342

Variable Costs DGGS		**Cost ($)**
Fuel Cost		20,236,553
Fuel Adjustment		0
Less Energy Supply 7 MW		(1,589,724)
Less Transmission Service @ 20%		(3,729,366)
Energy Supply 7 MW		1,589,724
Reg. Contract Capacity		0
Reg. Contract Energy		0
Less Transmission Service @ 20%		0
DGGS – Fuel Cost Allocation:		16,507,187

Revenue Credits 27 MW		(5,792,375)
Less Transmission Service @ 20%		1,158,475
Reg. Contract Revenue Credit		0
Less Transmission Service @ 20%		0
DGGS – Revenue Credit Allocation:		(4,633,900)

Incremental Property Tax Adjustment		671,472
DSM Lost Revenue		853,436
DSM Lost Revenue Adjustment		0
Subtotal DGGS Variable Cost Allocation		12,055,251

Carrying Cost		157,281
Total DGGS Variable Cost Allocation		12,212,532

Variable Revenues DGGS		**Revenue ($)**
Revenues		16,810,873

Ending Deferred DGGS		**Balance ($)**
Even Collection		0

Q. Does this conclude your Annual DGGS True-up testimony?

A. Yes, it does.

	A B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Dave Gates Generating Station at Mill Creek Asset Component**														
2			**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Total**
3			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	
4	**Dave Gates Generating Station Fixed Cost Revenue Requirement -- Per Order 6943e**														
5	DGGS Plant In Service														
6	Electric Generation Plant		$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 182,537,625
7	Accumulated Depreciation (Book Life 30 Yrs)		$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (8,953,885)
8	DGGS Project Costs		$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 231,716
9	Customer Contributed Capital		$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (3,115,352)
10	Working Capital		$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 1,980,537
11	Total Year End Rate Base		$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 172,680,641
12															
13	Fixed Return (Avg RB * Cost of Capital)	8.16%	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 14,090,740
14															
15	Fixed Cost of Service														
16	Operation & Maintenance Expenses		$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 4,849,385
17	Depreciation		$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 5,969,257
18	Amortization of DGGS Project Cost		$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 154,477
19	Property Taxes		$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 3,804,214
20	MPSC & MCC Revenue Tax		$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 125,086
21	Deferred Income Taxes		$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 6,300,004
22	Current Income Taxes		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Fixed Cost of Service		$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 21,202,423
24															
25	Subtotal Fixed Cost Revenue Requirement		$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 35,293,163
26															
27	Less: Transmission Service @ 20%		$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (7,058,633)
28															
29	DGGS Fixed Cost Allocation		$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 28,234,531
30															
31															
32	Total DGGS Fixed Cost Revenue Requirement		$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 28,234,531
33															

Dave Gates Generating Station at Mill Creek Asset Component

		Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Total
		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	
Dave Gates Generating Station at Mill Creek Variable Cost														
Total Forecast Sales														
2011/12 Tracker Sales MWh		508,737	551,049	516,614	445,633	451,251	507,415	565,008	522,733	487,459	461,420	447,693	453,829	5,918,840
DGGS Cost		$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	$ 1.2623	
Prior Year Deferred Expense		$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	$ (0.0271)	
DGGS Variable Cost Revenues														
NWE DGGS Revenues		$ 642,167	$ 695,490	$ 652,020	$ 562,135	$ 569,211	$ 640,401	$ 623,041	$ 608,024	$ 567,128	$ 536,560	$ 520,316	$ 527,448	$ 7,143,942
Prior Year(s) Deferred Expense		$ -	$ (63,708)	$ (177,559)	$ (153,083)	$ (155,010)	$ (174,394)	$ (194,198)	$ (179,625)	$ (167,541)	$ (158,515)	$ (12,137)	$ (12,303)	$ (1,448,074)
Total Revenue		$ 642,167	$ 631,782	$ 474,461	$ 409,052	$ 414,201	$ 466,007	$ 428,843	$ 428,400	$ 399,587	$ 378,046	$ 508,179	$ 515,145	$ 5,695,868
DGGS Fuel Cost														
DGGS Fuel Cost		$ 1,477,879	$ 1,425,995	$ 1,340,452	$ 1,726,625	$ 1,748,810	$ 1,701,594	$ 1,454,564	$ 1,342,614	$ 1,846,950	$ 1,178,481	$ 1,178,481	$ 1,178,481	$ 17,600,925
DGGS Fuel Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Energy Supply Cost (7 MW)		$ (132,477)	$ (132,477)	$ (132,477)	$ (132,477)	$ (132,477)	$ (132,477)	$ (132,477)	$ (132,477)	$ (132,477)	$ (125,144)	$ (125,144)	$ (125,144)	$ (1,567,725)
Subtotal		$ 1,345,402	$ 1,293,518	$ 1,207,975	$ 1,594,148	$ 1,616,333	$ 1,569,117	$ 1,322,087	$ 1,210,137	$ 1,714,473	$ 1,053,337	$ 1,053,337	$ 1,053,337	$ 16,033,200
Less: Transmission Service @ 20%		$ (269,080)	$ (258,704)	$ (241,595)	$ (318,830)	$ (323,267)	$ (313,823)	$ (264,417)	$ (242,027)	$ (342,895)	$ (210,667)	$ (210,667)	$ (210,667)	$ (3,206,640)
MPSC-Related Supply Cost		$ 1,076,322	$ 1,034,815	$ 966,380	$ 1,275,318	$ 1,293,067	$ 1,255,294	$ 1,057,670	$ 968,109	$ 1,371,578	$ 842,670	$ 842,670	$ 842,670	$ 12,826,560
Energy Supply Cost (7 MW)		$ 132,477	$ 132,477	$ 132,477	$ 132,477	$ 132,477	$ 132,477	$ 132,477	$ 132,477	$ 132,477	$ 125,144	$ 125,144	$ 125,144	$ 1,567,725
Subtotal MPSC-Related Fuel Cost		$ 1,208,799	$ 1,167,292	$ 1,098,857	$ 1,407,795	$ 1,425,544	$ 1,387,771	$ 1,190,147	$ 1,100,586	$ 1,504,055	$ 967,813	$ 967,813	$ 967,813	$ 14,394,285
Regulation Contracts														
Capacity		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Transmission Service @ 20%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal MPSC-Related Regulation Contract Cost		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DGGS Fuel Cost Allocation		$ 1,208,799	$ 1,167,292	$ 1,098,857	$ 1,407,795	$ 1,425,544	$ 1,387,771	$ 1,190,147	$ 1,100,586	$ 1,504,055	$ 967,813	$ 967,813	$ 967,813	$ 14,394,285
DGGS Revenue Credits														
Revenue Credits (27 MW Supply/Tran)		$ (200,692)	$ (634,737)	$ (540,398)	$ (768,900)	$ (644,837)	$ (554,320)	$ (531,367)	$ (536,023)	$ (846,465)	$ (482,698)	$ (482,698)	$ (482,698)	$ (6,705,833)
Less: Transmission Service @ 20%		$ 40,138	$ 126,947	$ 108,080	$ 153,780	$ 128,967	$ 110,864	$ 106,273	$ 107,205	$ 169,293	$ 96,540	$ 96,540	$ 96,540	$ 1,341,167
Subtotal MPSC-Related Revenue Credits		$ (160,554)	$ (507,790)	$ (432,319)	$ (615,120)	$ (515,869)	$ (443,456)	$ (425,094)	$ (428,819)	$ (677,172)	$ (386,158)	$ (386,158)	$ (386,158)	$ (5,364,666)
Regulation Contracts Revenue Credits														
Revenue Credits		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Transmission Service @ 20%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal MPSC-Related Revenue Credits		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DGGS Revenue Credit Allocation		$ (160,554)	$ (507,790)	$ (432,319)	$ (615,120)	$ (515,869)	$ (443,456)	$ (425,094)	$ (428,819)	$ (677,172)	$ (386,158)	$ (386,158)	$ (386,158)	$ (5,364,666)
Incremental Property Tax Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ (55,956)	$ (55,956)	$ (55,956)	$ (55,956)	$ (55,956)	$ (55,956)	$ (335,736)
DSM Lost Revenue		$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 44,928	$ 539,139
DSM Lost Revenue Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 69,822	$ -	$ 69,822
Subtotal DGGS Variable Cost Allocation		$ 1,093,173	$ 704,430	$ 711,466	$ 837,604	$ 954,602	$ 989,243	$ 754,025	$ 660,740	$ 815,855	$ 570,627	$ 640,449	$ 570,627	$ 9,302,844
Carrying Cost Expense														
Carrying Costs	7.80%	$ 7,886	$ 8,413	$ 10,017	$ 12,885	$ 16,503	$ 20,032	$ 22,289	$ 23,954	$ 26,832	$ 28,267	$ 29,316	$ 29,871	$ 236,264
Total DGGS Variable Cost Allocation		$ 1,101,059	$ 712,843	$ 721,484	$ 850,489	$ 971,105	$ 1,009,274	$ 776,314	$ 684,694	$ 842,687	$ 598,894	$ 669,766	$ 600,498	$ 9,539,107
Deferred Cost Amortization (Under)/Over		$ -	$ (63,708)	$ (177,559)	$ (153,083)	$ (155,010)	$ (174,394)	$ (194,198)	$ (179,625)	$ (167,541)	$ (158,515)	$ (12,137)	$ (12,303)	$ (1,448,074)
Monthly Deferred Cost		$ (458,893)	$ (17,354)	$ (69,463)	$ (288,354)	$ (401,894)	$ (368,873)	$ (153,273)	$ (76,669)	$ (275,559)	$ (62,334)	$ (149,449)	$ (73,050)	$ (2,395,166)
Cumulative Deferred Cost		$ (458,893)	$ (476,246)	$ (545,710)	$ (834,064)	$ (1,235,958)	$ (1,604,831)	$ (1,758,104)	$ (1,834,773)	$ (2,110,333)	$ (2,172,666)	$ (2,322,116)	$ (2,395,166)	
Variable Rate-Base Deferred														
Beginning Balance		$ 755,103	$ 1,213,996	$ 1,295,057	$ 1,542,080	$ 1,983,517	$ 2,540,421	$ 3,083,689	$ 3,431,159	$ 3,687,453	$ 4,130,554	$ 4,351,402	$ 4,512,989	
Monthly Deferred Cost		$ 458,893	$ 81,062	$ 247,022	$ 441,437	$ 556,904	$ 543,268	$ 347,471	$ 256,294	$ 443,101	$ 220,848	$ 161,586	$ 85,354	
Ending Balance Under/(Over)		$ 1,213,996	$ 1,295,057	$ 1,542,080	$ 1,983,517	$ 2,540,421	$ 3,083,689	$ 3,431,159	$ 3,687,453	$ 4,130,554	$ 4,351,402	$ 4,512,989	$ 4,598,342	

	A B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Dave Gates Generating Station at Mill Creek Asset Component**														
2			**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Total**
3			Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
4	**Dave Gates Generating Station Fixed Cost Revenue Requirement -- Per Order 6943e**														
5	DGGS Plant In Service														
6	Electric Generation Plant		$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 15,211,469	$ 182,537,625
7	Accumulated Depreciation (Book Life 30 Yrs)		$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (746,157)	$ (8,953,885)
8	DGGS Project Costs		$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 19,310	$ 231,716
9	Customer Contributed Capital		$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (259,613)	$ (3,115,352)
10	Working Capital		$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 165,045	$ 1,980,537
11	Total Year End Rate Base		$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 14,390,053	$ 172,680,641
12															
13	Fixed Return (Avg RB * Cost of Capital)	8.16%	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 1,174,228	$ 14,090,740
14															
15	Fixed Cost of Service														
16	Operation & Maintenance Expenses		$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 404,115	$ 4,849,385
17	Depreciation		$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 497,438	$ 5,969,257
18	Amortization of DGGS Project Cost		$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 12,873	$ 154,477
19	Property Taxes		$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 317,018	$ 3,804,214
20	MPSC & MCC Revenue Tax		$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 10,424	$ 125,086
21	Deferred Income Taxes		$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 525,000	$ 6,300,004
22	Current Income Taxes		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Fixed Cost of Service		$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 1,766,869	$ 21,202,423
24															
25	Subtotal Fixed Cost Revenue Requirement		$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 2,941,097	$ 35,293,163
26															
27	Less: Transmission Service @ 20%		$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (588,219)	$ (7,058,633)
28															
29	DGGS Fixed Cost Allocation		$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 28,234,531
30															
31															
32	Total DGGS Fixed Cost Revenue Requirement		$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 2,352,878	$ 28,234,531
33															

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
34	**Dave Gates Generating Station at Mill Creek Asset Component**															
35				**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Total**
36				Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
37	**Dave Gates Generating Station at Mill Creek Variable Cost**															
38	Total Forecast Sales															
39		2011/12 Tracker Sales MWh		510,194	533,603	488,645	465,210	483,078	530,062	563,388	525,942	497,190	474,079	453,460	462,147	5,986,998
40		DGGS Cost		$ 2.0398	$ 2.0398	$ 2.0398	$ 2.0398	$ **2.0398**	$ 2.0398	$ 2.0398	$ 2.0398	$ 2.0398	$ 2.0398	$ 2.0398	$ 2.0398	
41		Prior Year Deferred Expense		$ 0.7681	$ 0.7681	$ 0.7681	$ 0.7681	$ 0.7681	$ 0.7681	$ 0.7681	$ 0.7681	$ 0.7681	$ 0.7681	$ 0.7681	$ 0.7681	
42																
43	DGGS Variable Cost Revenues															
44		NWE DGGS Revenues		$ 1,040,714	$ 1,088,466	$ 996,760	$ 948,955	$ 985,402	$ 1,081,242	$ 1,149,222	$ 1,072,840	$ 1,014,190	$ 967,047	$ 924,988	$ 942,707	$ 12,212,531
45		Prior Year(s) Deferred Expense		$ 391,857	$ 409,836	$ 375,306	$ 357,307	$ 371,030	$ 407,116	$ 432,712	$ 403,953	$ 381,869	$ 364,119	$ 348,282	$ 354,954	$ 4,598,342
46	Total Revenue			$ 1,432,571	$ 1,498,302	$ 1,372,066	$ 1,306,262	$ 1,356,432	$ 1,488,359	$ 1,581,934	$ 1,476,792	$ 1,396,059	$ 1,331,166	$ 1,273,270	$ 1,297,661	$ 16,810,873
47																
48	DGGS Fuel Cost															
49		DGGS Fuel Cost		$ 1,686,379	$ 1,686,379	$ 1,686,379	$ 1,686,379	$ 1,686,379	$ 1,686,379	$ 1,686,379	$ 1,686,379	$ 1,686,379	$ 1,686,379	$ 1,686,379	$ 1,686,379	$ 20,236,553
50		DGGS Fuel Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51		Less: Energy Supply Cost (7 MW)		$ (132,477)	$ (132,477)	$ (132,477)	$ (132,477)	$ (132,477)	$ (132,477)	$ (132,477)	$ (132,477)	$ (132,477)	$ (132,477)	$ (132,477)	$ (132,477)	$ (1,589,724)
52		Subtotal		$ 1,553,902	$ 1,553,902	$ 1,553,902	$ 1,553,902	$ 1,553,902	$ 1,553,902	$ 1,553,902	$ 1,553,902	$ 1,553,902	$ 1,553,902	$ 1,553,902	$ 1,553,902	$ 18,646,829
53		Less: Transmission Service @ 20%		$ (310,780)	$ (310,780)	$ (310,780)	$ (310,780)	$ (310,780)	$ (310,780)	$ (310,780)	$ (310,780)	$ (310,780)	$ (310,780)	$ (310,780)	$ (310,780)	$ (3,729,366)
54		MPSC-Related Supply Cost		$ 1,243,122	$ 1,243,122	$ 1,243,122	$ 1,243,122	$ 1,243,122	$ 1,243,122	$ 1,243,122	$ 1,243,122	$ 1,243,122	$ 1,243,122	$ 1,243,122	$ 1,243,122	$ 14,917,463
55		Energy Supply Cost (7 MW)		$ 132,477	$ 132,477	$ 132,477	$ 132,477	$ 132,477	$ 132,477	$ 132,477	$ 132,477	$ 132,477	$ 132,477	$ 132,477	$ 132,477	$ 1,589,724
56	Subtotal MPSC-Related Fuel Cost			$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 16,507,187
57																
58	Regulation Contracts															
59		Capacity		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60		Energy		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61		Subtotal		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62		Less: Transmission Service @ 20%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	Subtotal MPSC-Related Regulation Contract Cost			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64																
65	DGGS Fuel Cost Allocation			$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 1,375,599	$ 16,507,187
66																
67	DGGS Revenue Credits															
68		Revenue Credits (27 MW Supply/Tran)		$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (482,698)	$ (5,792,375)
69		Less: Transmission Service @ 20%		$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 96,540	$ 1,158,475
70		Subtotal MPSC-Related Revenue Credits		$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (4,633,900)
71																
72	Regulation Contracts Revenue Credits															
73		Revenue Credits		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74		Less: Transmission Service @ 20%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75	Subtotal MPSC-Related Revenue Credits			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76																
77	DGGS Revenue Credit Allocation			$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (386,158)	$ (4,633,900)
78																
79		Incremental Property Tax Adjustment		$ (55,956)	$ (55,956)	$ (55,956)	$ (55,956)	$ (55,956)	$ (55,956)	$ (55,956)	$ (55,956)	$ (55,956)	$ (55,956)	$ (55,956)	$ (55,956)	$ (671,472)
80																
81		DSM Lost Revenue		$ 71,120	$ 71,120	$ 71,120	$ 71,120	$ 71,120	$ 71,120	$ 71,120	$ 71,120	$ 71,120	$ 71,120	$ 71,120	$ 71,120	$ 853,436
82		DSM Lost Revenue Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
83																
84	Subtotal DGGS Variable Cost Allocation			$ 1,004,604	$ 1,004,604	$ 1,004,604	$ 1,004,604	$ 1,004,604	$ 1,004,604	$ 1,004,604	$ 1,004,604	$ 1,004,604	$ 1,004,604	$ 1,004,604	$ 1,004,604	$ 12,055,251
85																
86	**Carrying Cost Expense**															
87		Carrying Costs	7.80%	$ 27,268	$ 24,218	$ 21,974	$ 20,145	$ 17,976	$ 14,931	$ 11,254	$ 8,240	$ 5,734	$ 3,637	$ 1,904	$ 0	$ 157,281
88																
89	Total DGGS Variable Cost Allocation			$ 1,031,872	$ 1,028,822	$ 1,026,578	$ 1,024,749	$ 1,022,581	$ 1,019,535	$ 1,015,858	$ 1,012,844	$ 1,010,339	$ 1,008,241	$ 1,006,508	$ 1,004,604	$ 12,212,532
90																
91		Deferred Cost Amortization (Under)/Over		$ 391,857	$ 409,836	$ 375,306	$ 357,307	$ 371,030	$ 407,116	$ 432,712	$ 403,953	$ 381,869	$ 364,119	$ 348,282	$ 354,954	$ 4,598,342
92		Monthly Deferred Cost		$ 8,842	$ 59,644	$ (29,818)	$ (75,795)	$ (37,179)	$ 61,707	$ 133,364	$ 59,995	$ 3,851	$ (41,194)	$ (81,520)	$ (61,897)	$ 0
93	Cumulative Deferred Cost			$ 8,842	$ 68,486	$ 38,667	$ (37,127)	$ (74,306)	$ (12,599)	$ 120,765	$ 180,760	$ 184,611	$ 143,417	$ 61,897	$ 0	
94																
95	Variable Rate Base Deferred															
96		Beginning Balance		**$ 4,598,342**	$ 4,197,644	$ 3,728,164	$ 3,382,676	$ 3,101,164	$ 2,767,312	$ 2,298,489	$ 1,732,413	$ 1,268,465	$ 882,745	$ 559,820	$ 293,058	
97		Monthly Deferred Cost		$ (400,699)	$ (469,480)	$ (345,488)	$ (281,512)	$ (333,851)	$ (468,823)	$ (566,076)	$ (463,948)	$ (385,720)	$ (322,925)	$ (266,762)	$ (293,057)	
98		Ending Balance Under/(Over)		$ 4,197,644	$ 3,728,164	$ 3,382,676	$ 3,101,164	$ 2,767,312	$ 2,298,489	$ 1,732,413	$ 1,268,465	$ 882,745	$ 559,820	$ 293,058	$ 0	

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.5.33
Annual DGGS True-up
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF CHERYL A. HANSEN

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL DAVE GATES GENERATING STATION (“DGGS”) TRUE-UP

TABLE OF CONTENTS

Witness Information

Q. Are you the same Cheryl A. Hansen who filed prefiled direct testimony in the Electricity Supply Tracker portion of this docket?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your Annual DGGS True-up testimony?

A. This testimony:

1. Presents the derivation of proposed deferred DGGS variable rates resulting from the over/under collection reflected in both the 2011-2012 true-up period and the 2012-2013 true-up period;
2. Presents the derivation of proposed DGGS variable rates for the forecasted 2013-2014 true-up period; and
3. Discusses the overall total supply rates incorporating all individual rate components.

Derivation of Proposed Deferred DGGS Variable Rates

Q. What is the DGGS variable cost account balance for the 12-month period ending June 2013?

A. The DGGS variable cost account balance for the 12-month period ending June 2013 is an under-collection of $4,598,342 as presented on page 1 of Exhibit__(CAH-4)13-14. As discussed below, this includes the prior period balance for the 2011-2012 true-up period and the current period balance for the 2012-2013 true-up period.

Q. Describe the status of the deferred DGGS variable cost account balance associated with the 2011-2012 true-up period.

A. In the annual filing submitted on May 31, 2012, the net deferred account balance for the 2011-2012 true-up period was shown as an over-collection of $(161,231). This amount becomes the starting balance in this filing. Added to this balance is the prior period true-up for the 2 months of estimated data included in the May 2012 filing. Page 1 of Exhibit__(CAH-4)13-14 shows the true-up of the previously estimated months of May and June 2012 with actual data for these months. This results in an actual under-collected ending balance of $755,103.

Next, an adjustment is included to reflect compliance with Docket No. D2012.5.49, Interim Order No. 7219a ("Interim Order"). As directed in the Interim Order, the deferred rates that went into effect August 1, 2012 were based on an over-collected balance of $(1,861,161). The difference between the Interim Order amount and the actual ending balance discussed above is $(2,616,264). The resulting adjusted balance of $(1,861,161) is the deferred account beginning balance for the 2012-2013 true-up period. This amount combined with the current year monthly activity shown on Exhibit__(CAH-4)13-14, page 1, and the add back of the

$2,616,264 adjusted amount results in an under-collected balance of $2,203,177 for the 2011-2012 true-up period. The months of April, May and June 2013 are estimated and will be trued-up in the next annual filing.

Q. Describe the DGGS variable cost account balance associated with the 2012-2013 true-up period.

A. Page 2 of Exhibit__(CAH-4)13-14 shows the monthly detail of the difference between the DGGS variable cost revenues and expenses for the 2012-2013 true-up period, resulting in an under-collected amount of $2,395,166. The months of April, May and June 2013 are estimated and will be trued-up in the next annual filing.

Q. What is the total deferred DGGS variable cost account adjustment proposed for amortization in this filing?

A. The total deferred DGGS variable cost account adjustment proposed in this filing is an under-collection of $4,598,342 shown below and on page 1, line 55 of Exhibit__(CAH-4)13-14.

Total Deferred DGGS Variable Cost Account Balance

2011-2012 Prior Period DGGS Variable Account Balance	$2,203,177
2012-2013 Current Period DGGS Variable Account Balance	$2,395,166
	$4,598,342

Derivation of the deferred DGGS variable rates is shown on Exhibit__(CAH-4)13-14, page 3 with the resulting rates and revenues shown on page 4.

Derivation of Proposed DGGS Variable Rates

Q. Please describe the process used by NorthWestern to derive the proposed 2013-2014 forecasted DGGS variable rates in this filing.

A. The rate design methodology used in this filing to derive the proposed 2013-2014 forecasted DGGS variable rates is the same as that presented in previous DGGS filings. All forecasted costs are from Exhibit__(FVB-7)13-14 of the Prefiled Direct Testimony of Frank V. Bennett and are discussed therein.

Derivation of the DGGS variable rates is shown on Exhibit__(CAH-4)13-14, page 5. The total DGGS variable cost of $12,212,532 is the sum of forecasted fuel costs, revenue credits, DSM Lost Revenues, incremental property taxes, carrying costs, and the energy supply costs for the 7MW from Exhibit__(FVB-7)13-14. This sum is the amount used to derive the DGGS variable rates. The forecasted loads used in the derivation of rates are from Exhibit__(CAH-1)13-14, page 6. The resulting rates are the DGGS variable rates proposed in this filing.

Q. Please describe the 2013-2014 DGGS fixed cost rates included in this filing.

A. The DGGS fixed cost of service rate components presented in this filing are those submitted in compliance with Docket No. D2008.8.95 Order No. 6943e. The DGGS fixed rate components include rates effective January 1, 2012 reflecting the second year revenue requirement and will not change until an order is issued in any subsequent revenue requirement filing that deals with DGGS.

Page 6 of Exhibit__(CAH-4)13-14 reflects the DGGS fixed and variable rates and revenues in summarized format.

Q. Please describe the status of the DGGS fixed cost rebate rates submitted in compliance with Docket No. D2008.8.95 Order No. 6943e.

A. Docket No. D2008.8.95 Order No. 6943e ("Order") directed NWE to refund to ratepayers a net over-collected amount, including interest. The net over-collection represented the differences between the first and second year revenue requirements approved on a final basis in the Order and what was approved in Interim Order Nos. 6943b and 6943c. NWE was directed to credit the over-collection balance to customers over a one-year period or until such time that the balance was extinguished. In compliance with the Order, NWE proposed in the May 2012 Electric Supply monthly filing DGGS fixed cost rebate rates effective May 1, 2012. By letter dated May 10, 2013 NWE noted that the over-collection balance was close to being extinguished and requested that the DGGS fixed cost rebate rates be expired and set to zero effective May 13, 2013.

<u>Proposed Total Deferred Supply and Total Supply Rates</u>

Q. Please describe the process used by NorthWestern to derive the total 2013-2014 deferred supply rates proposed in this filing.

A. The total deferred supply rate includes three separate rate components – a deferred electricity supply rate, a deferred Colstrip Unit 4 ("CU4") variable rate, and a deferred DGGS variable rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(CAH-6)13-14, page 1.

Q. Please describe the process used by NorthWestern to derive the total 2013-2014 supply rates proposed in this filing.

A. The total electric supply rate currently includes several separate rate components – an electricity supply tracker rate, a CU4 fixed cost of service rate, a CU4 variable rate, a DGGS fixed cost of service rate, a DGGS variable rate, a Spion Kop Wind Generation Asset ("Spion") fixed cost of service rate, and a Spion variable rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(CAH-6)13-14, page 3.

Q. Does this conclude your Annual DGGS True-up testimony?

A. Yes, it does.

NorthWestern Energy
Electric Utility
Deferred DGGS Variable Cost Account Balance
July 2012 - June 2013

Month	Monthly Collection	Collection to-date	Balance Remaining
Jul11-Jun12 over-collected balance as filed in D2012.5.49			**$ (161,231)**
Prior Period Jul11-Jun12 True-up - Variable:			
May12: Revenue - Estimated as filed in D2012.5.49	$ 834,121		
May12: Revenue - Actual	$ 811,067	$ (23,053)	
May12: Expense - Estimated as filed in D2012.5.49	$ 678,068		
May12: Expense - Actual	$ 1,172,029	$ 493,961	$ 517,014
Jun12: Revenue - Estimated as filed in D2012.5.49	$ 915,856		
Jun12: Revenue - Actual	$ 848,107	$ (67,749)	
Jun12: Expense - Estimated as filed in D2012.5.49	$ 624,993		
Jun12: Expense - Actual	$ 956,564	$ 331,571	$ 399,320
Actual Jul11-Jun12 under-collected balance[1]			**$ 755,103**
			-
Adjustment to reflect Interim Order 7219a			$ (2,616,264)
Interim Order 7219a Jul11-Jun12 over-collected balance			**$ (1,861,161)**
Rates effective 8/1/2012.			
Deferred Jul12-Jun13 Monthly Activity[2]:			
July 2012	$ -	$ -	$ (1,861,161)
August 2012	$ (63,708)	$ (63,708)	$ (1,797,453)
September 2012	$ (177,559)	$ (241,267)	$ (1,619,894)
October 2012	$ (153,083)	$ (394,350)	$ (1,466,811)
November 2012	$ (155,010)	$ (549,360)	$ (1,311,801)
December 2012	$ (174,394)	$ (723,755)	$ (1,137,406)
January 2013	$ (194,198)	$ (917,952)	$ (943,209)
February 2013	$ (179,625)	$ (1,097,577)	$ (763,584)
March 2013	$ (167,541)	$ (1,265,119)	$ (596,042)
April 2013 - Estimated	$ (158,515)	$ (1,423,633)	$ (437,528)
May 2013 - Estimated	$ (12,137)	$ (1,435,770)	$ (425,391)
June 2013 - Estimated	$ (12,303)	$ (1,448,074)	$ (413,087)
		-	
Add back Interim Order 7219a Jul11-Jun12 adjustment			$ 2,616,264
Prior Period Jul11-Jun12 DGGS Variable Cost Ending Balance			**$ 2,203,177**
Current Period Jul12-Jun13 DGGS Variable Cost Ending Balance (see page 2)			**$ 2,395,166**
Total DGGS Variable Cost Balance Jul12-Jun13[3]			**$ 4,598,342**
			-

[1]Source: Exhibit_(FVB-6)12-13, page 2, line 96, col D.
[2]Source: Exhibit_(FVB-6)12-13, page 2, line 91.
[3]Source: Exhibit_(FVB-6)12-13, page 2, line 98, col O.

NorthWestern Energy
Electric Utility
DGGS Variable Cost Account Balance
July 2012 - June 2013

Month	DGGS Variable Cost Revenue	DGGS Variable Cost Expense	DGGS Variable Cost Balance
July 2012	$ 642,167	$ 1,101,059	$ 458,893
August 2012	$ 695,490	$ 712,843	$ 17,354
September 2012	$ 652,020	$ 721,484	$ 69,463
October 2012	$ 562,135	$ 850,489	$ 288,354
November 2012	$ 569,211	$ 971,105	$ 401,894
December 2012	$ 640,401	$ 1,009,274	$ 368,873
January 2013	$ 623,041	$ 776,314	$ 153,273
February 2013	$ 608,024	$ 684,694	$ 76,669
March 2013	$ 567,128	$ 842,687	$ 275,559
April 2013 - Estimated	$ 536,560	$ 598,894	$ 62,334
May 2013 - Estimated	$ 520,316	$ 669,766	$ 149,449
June 2013 - Estimated	$ 527,448	$ 600,498	$ 73,050
DGGS Cost Balance Jul12-Jun13	**$ 7,143,942**	**$ 9,539,107**	**$ 2,395,166**
	-	-	-

Source:
Revenue: Exhibit_(FVB-6)12-13, page 2, line 44.
Expense: Exhibit_(FVB-6)12-13, page 2, line 91.

Northwestern Energy
Electric Utility Derivation of Rates
Deferred DGGS Variable
Tracker Period July 2013 to June 2014

Customer Rate Class	Loss Factor	Jul13 to Jun14 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	Deferred DGGS Variable Rate After Losses	Deferred DGGS Variable Revenue Check
Residential	8.5100%	2,356,022,192	2,356,022,192	2,556,519,680	$ 0.000772	$ 1,818,849
Residential Employee	8.5100%	3,886,619	2,331,972	2,530,422	$ 0.000463	$ 1,800
GS 1 Secondary NonDemand	8.5100%	279,360,817	279,360,817	303,134,423	$ 0.000772	$ 215,667
GS 1 Secondary Demand	8.5100%	2,477,871,468	2,477,871,468	2,688,738,330	$ 0.000772	$ 1,912,917
GS 1 Primary NonDemand	5.5400%	563,318	563,318	594,526	$ 0.000750	$ 422
GS 1 Primary Demand	5.5400%	357,213,999	357,213,999	377,003,654	$ 0.000750	$ 267,910
General Service Substation	4.6300%	232,669,987	232,669,987	243,442,607	$ 0.000744	$ 173,106
General Service Transmission	4.0000%	135,701,068	135,701,068	141,129,111	$ 0.000739	$ 100,283
Irrigation	8.5100%	86,094,805	86,094,805	93,421,473	$ 0.000772	$ 66,465
Lighting	8.5100%	57,613,774	57,613,774	62,516,706	$ 0.000772	$ 44,478
		5,986,998,047	5,985,443,400	6,469,030,933	$ 0.000769	$ 4,601,898
YNP Contract		19,233,936			Rounding Adjustment	$ (3,555)
Total Supply Load		6,006,231,983				$ 4,598,342
		6,006,232				

2012-13 Deferred DGGS Variable Cost Under-Collection	**$**	**4,598,342**
Total Deferred CU4 Variable Rate Before Losses	$	0.000711
Total Deferred CU4 Variable Rate After Losses	$	0.000769

NorthWestern Energy
Electric Utility
Deferred DGGS Variable Revenue ($000) Summary
Tracker Period July 2013 to June 2014

	Jul13 to Jun14 Supply Retail kWh Sales	**Current Deferred DGGS Rates[1]**	**Current Deferred DGGS Revenue**	**Proposed Deferred DGGS Rates 7/1/2013**	**Proposed Deferred DGGS Revenue**	**Revenue Diff Proposed vs Current**
Residential						
Residential	2,356,022	$ (0.000345)	$ (813)	$ 0.000772	$ 1,819	$ 2,632
Residential Employee	3,887	$ (0.000207)	$ (1)	$ 0.000463	$ 2	$ 3
Total Residential			$ (814)		$ 1,821	$ 2,634
General Service 1						
GS-1 Sec Non Demand	279,361	$ (0.000345)	$ (96)	$ 0.000772	$ 216	$ 312
GS-1 Sec Demand	2,477,871	$ (0.000345)	$ (855)	$ 0.000772	$ 1,913	$ 2,768
GS-1 Pri Non Demand	563	$ (0.000336)	$ (0)	$ 0.000750	$ 0	$ 1
GS-1 Pri Demand	357,214	$ (0.000336)	$ (120)	$ 0.000750	$ 268	$ 388
Total GS-1			$ (1,071)		$ 2,397	$ 3,468
General Service 2						
GS-2 Substation	232,670	$ (0.000333)	$ (77)	$ 0.000744	$ 173	$ 251
GS-2 Transmission	135,701	$ (0.000331)	$ (45)	$ 0.000739	$ 100	$ 145
Total GS-2			$ (122)		$ 273	$ 396
Irrigation						
Irrigation	86,095	$ (0.000345)	$ (30)	$ 0.000772	$ 66	$ 96
Total Irrigation			$ (30)		$ 66	$ 96
Lighting						
Lighting	57,614	$ (0.000345)	# $ (20)	$ 0.000772	$ 44	$ 64
Total Lighting			$ (20)		$ 44	$ 64
Total Rate Schedule	**5,986,998**		**$ (2,057)**		**$ 4,602**	**$ 6,658.964**
	-				-	

[1]Docket No. D2012.5.49, Interim Order No. 7219a in August 2012 Electric Supply monthly filing, effective 8/1/2012.

Northwestern Energy
Electric Utility Derivation of Rates
DGGS Variable Cost of Service
Tracker Period July 2013 to June 2014

Customer Rate Class	Loss Factor	Jul13 to Jun14 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	DGGS Variable After Losses kWh Charges	DGGS Variable Revenue/Cost Check
Residential	8.5100%	2,356,022,192	2,356,022,192	2,556,519,680	$ 0.002049	$ 4,827,489
Residential Employee	8.5100%	3,886,619	2,331,972	2,530,422	$ 0.001230	$ 4,781
GS 1 Secondary NonDemand	8.5100%	279,360,817	279,360,817	303,134,423	$ 0.002049	$ 572,410
GS 1 Secondary Demand	8.5100%	2,477,871,468	2,477,871,468	2,688,738,330	$ 0.002049	$ 5,077,159
GS 1 Primary NonDemand	5.5400%	563,318	563,318	594,526	$ 0.001993	$ 1,123
GS 1 Primary Demand	5.5400%	357,213,999	357,213,999	377,003,654	$ 0.001993	$ 711,927
General Service Substation	4.6300%	232,669,987	232,669,987	243,442,607	$ 0.001975	$ 459,523
General Service Transmission	4.0000%	135,701,068	135,701,068	141,129,111	$ 0.001964	$ 266,517
Irrigation	8.5100%	86,094,805	86,094,805	93,421,473	$ 0.002049	$ 176,408
Lighting	8.5100%	57,613,774	57,613,774	62,516,706	$ 0.002049	$ 118,051
		5,986,998,047	5,985,443,400	6,469,030,933	$ 0.002041	$ 12,215,388
YNP Contract		19,233,936			Rounding Adjustment	$ (2,856)
Total Supply Load		6,006,231,983				$ 12,212,532
		-				

2013-14 DGGS Variable Cost of Service	**$**	**12,212,532**
Total DGGS Variable COS Rate Before Losses	$	0.001888
Total DGGS Variable COS Rate After Losses	$	0.002040

NorthWestern Energy
Electric Utility
Total DGGS Revenue ($000) Summary
Tracker Period July 2013 to June 2014

		DGGS Fixed		DGGS Variable				
	Jul13 to Jun14 Supply Retail kWh Sales	**Current Rates[1]**	**Current Rate Revenue**	**Current Rates[2]**	**Current Rate Revenue**	**Proposed Rates 7/1/2013**	**Proposed Rate Revenue**	**Revenue Diff Proposed vs Current**
Residential								
Residential	2,356,022	0.004795	$ 11,297	0.001168	$ 2,752	0.002049	$ 4,827	$ 2,076
Residential Employee	3,887	0.002877	$ 11	0.000701	$ 3	0.001230	$ 5	$ 2
Total Residential			$ 11,308		$ 2,755		$ 4,832	$ 2,078
General Service 1								
GS-1 Sec Non Demand	279,361	0.004795	$ 1,340	0.001168	$ 326	0.002049	$ 572	$ 246
GS-1 Sec Demand	2,477,871	0.004795	$ 11,881	0.001168	$ 2,894	0.002049	$ 5,077	$ 2,183
GS-1 Pri Non Demand	563	0.004664	$ 3	0.001136	$ 1	0.001993	$ 1	$ 0
GS-1 Pri Demand	357,214	0.004664	$ 1,666	0.001136	$ 406	0.001993	$ 712	$ 306
Total GS-1			$ 14,890		$ 3,627		$ 6,363	$ 2,736
General Service 2								
GS-2 Substation	232,670	0.004624	$ 1,076	0.001126	$ 262	0.001975	$ 460	$ 198
GS-2 Transmission	135,701	0.004596	$ 624	0.001119	$ 152	0.001964	$ 267	$ 115
Total GS-2			$ 1,700		$ 414		$ 726	$ 312
Irrigation								
Irrigation	86,095	0.004795	$ 413	0.001168	$ 101	0.002049	$ 176	$ 76
Total Irrigation			$ 413		$ 101		$ 176	$ 76
Lighting								
Lighting	57,614	0.004795	$ 276	0.001168	$ 67	0.002049	$ 118	$ 51
Total Lighting			$ 276		$ 67		$ 118	$ 51
Total Rate Schedule	**5,986,998**		**$ 28,587**		**$ 6,963**		**$ 12,215**	**$ 5,252.260**
	-						-	

[1]DGGS Rates (based on 2nd yr rev req) approved in Docket No. D2008.8.95 Order No.6943e, effective 1/1/2012.
[2]DGGS Variable Rates updated for property taxes in February 2013 Electric Supply monthly filing, effective 2/1/2013.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.5.33
Annual Spion True-up
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF FRANK V. BENNETT

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL SPION KOP WIND GENERATION ASSET ("SPION") TRUE-UP

TABLE OF CONTENTS

Witness Information

Q. Are you the same Frank V. Bennett who filed prefiled direct testimony in the Electricity Supply Tracker portion of this docket?

A. Yes.

Purpose of Testimony

Q. Please describe this portion of your testimony.

A. In my testimony, I present the following information:

- The forecast Spion costs for the 12-month ended June 2014 forecast period.

Forecast for Spion Values in the 2013/2014 Period

Q. What has NorthWestern included in this filing as Spion variable costs?

A. NorthWestern has included in this forecast the DSM lost revenues associated with the Spion fixed costs in a manner similar to the inclusion of lost revenues associated with the fixed costs of its other rate-based generation.

Q. Are other potential variable costs possible for Spion during the 2013/2014 period?

A. Yes. It is anticipated that property taxes associated with Spion will change as a result of NWE's 2014 property tax tracker filing, which will be submitted in December 2013. Any such change would likely be reflected in the January 2014 Monthly Electric Supply Cost Rate Adjustment request.

Q. Describe the Spion variable Revenue and Cost categories for the 12-month ended June 2014 forecast period.

A. The Spion variable cost revenue and expense details are reflected on page 2 of Exhibit__(FVB-8)13-14 under two main sections: Total Revenue and Total Variable Cost. The 12-month forecast estimates both Total Revenue and Total Variable Costs of $87,012.

Q. Please provide a summary table of the 12-month ended June 2014 Spion forecast period.

A. The Spion forecast period is summarized in the following table:

Beginning Deferred Spion	**Balance ($)**
No prior value	0

Variable Costs Spion	**Cost ($)**
Incremental Property Tax Adjustments	0
DSM Lost Revenue	69,719
DSM Lost Revenue Adjustment	16,791
Subtotal Spion Variable Cost:	86,510

Carrying Costs	502
Total Variable Costs	87,012

Variable Revenues Spion	**Revenue ($)**
Revenues	87,012
Prior Year Deferred	0
Subtotal Revenues:	87,012

Ending Deferred Spion	**Balance ($)**
Even Collection	0

Q. Does this conclude your Annual Spion True-up testimony?

A. Yes, it does.

	A / B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Spion Kop Asset Component**														
2			**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Total**
3			Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
4	**Spion Kop Fixed Cost Revenue Requirement – Per Order 7159l**														
5	Spion Kop Plant In Service														
6	Electric Generation Plant		$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 6,991,746	$ 83,900,949
7	Accumulated Depreciation		$ (139,004)	$ (139,004)	$ (139,004)	$ (139,004)	$ (139,004)	$ (139,004)	$ (139,004)	$ (139,004)	$ (139,004)	$ (139,004)	$ (139,004)	$ (139,004)	$ (1,668,042)
8	Total Net Plant		$ 6,852,742	$ 6,852,742	$ 6,852,742	$ 6,852,742	$ 6,852,742	$ 6,852,742	$ 6,852,742	$ 6,852,742	$ 6,852,742	$ 6,852,742	$ 6,852,742	$ 6,852,742	$ 82,232,907
9															
10	Accelerated Tax Depreciation		$ 683,157	$ 683,157	$ 683,157	$ 683,157	$ 683,157	$ 683,157	$ 683,157	$ 683,157	$ 683,157	$ 683,157	$ 683,157	$ 683,157	$ 8,197,884
11	NOL Deferred Tax Asset		$ (797,984)	$ (797,984)	$ (797,984)	$ (797,984)	$ (797,984)	$ (797,984)	$ (797,984)	$ (797,984)	$ (797,984)	$ (797,984)	$ (797,984)	$ (797,984)	$ (9,575,802)
12	Total Customer Contributed Capital		$ (114,827)	$ (114,827)	$ (114,827)	$ (114,827)	$ (114,827)	$ (114,827)	$ (114,827)	$ (114,827)	$ (114,827)	$ (114,827)	$ (114,827)	$ (114,827)	$ (1,377,918)
13															
14	Total Year End Rate Base		$ 6,967,569	$ 6,967,569	$ 6,967,569	$ 6,967,569	$ 6,967,569	$ 6,967,569	$ 6,967,569	$ 6,967,569	$ 6,967,569	$ 6,967,569	$ 6,967,569	$ 6,967,569	$ 83,610,825
15															
16	Fixed Return (Avg RB * Cost of Capital)	7.00%	$ 487,730	$ 487,730	$ 487,730	$ 487,730	$ 487,730	$ 487,730	$ 487,730	$ 487,730	$ 487,730	$ 487,730	$ 487,730	$ 487,730	$ 5,852,758
17															
18	Fixed Cost of Service														
19	Operation & Maintenance Turbine Expense		$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 145,208	$ 1,742,500
20	Landowner Maintenance Expense		$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 12,000
21	Landowner Right of Way Expense		$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 1,023	$ 12,280
22	Royalty Fee		$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 15,543	$ 186,521
23	Administrative and General Expense		$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 19,750	$ 237,000
24	Depreciation		$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 278,007	$ 3,336,078
25	Wind Generation Facility Impact Fee		$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 13,110	$ 157,314
26	Property & Other Taxes		$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 36,650	$ 439,798
27	MPSC & MCC Revenue Tax	0.53%	$ 2,746	$ 2,746	$ 2,746	$ 2,746	$ 2,746	$ 2,746	$ 2,746	$ 2,746	$ 2,746	$ 2,746	$ 2,746	$ 2,746	$ 32,952
28	Deferred Income Taxes		$ (229,653)	$ (229,653)	$ (229,653)	$ (229,653)	$ (229,653)	$ (229,653)	$ (229,653)	$ (229,653)	$ (229,653)	$ (229,653)	$ (229,653)	$ (229,653)	$ (2,755,841)
29	Current Income Taxes		$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (253,000)	$ (3,036,000)
30	Fixed Cost of Service		$ 30,384	$ 30,384	$ 30,384	$ 30,384	$ 30,384	$ 30,384	$ 30,384	$ 30,384	$ 30,384	$ 30,384	$ 30,384	$ 30,384	$ 364,602
31															
32	Total Spion Kop Fixed Cost Revenue Requirement		$ 518,113	$ 518,113	$ 518,113	$ 518,113	$ 518,113	$ 518,113	$ 518,113	$ 518,113	$ 518,113	$ 518,113	$ 518,113	$ 518,113	$ 6,217,360
33															

	A / B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
34	**Spion Kop Asset Component**														
35			**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jan-00**
36			Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
37	**Spion Kop Variable Cost**														
38	Total Forecast Sales														
39	2011/12 Tracker Sales MWh		510,194	533,603	488,645	465,210	483,078	530,062	563,388	525,942	497,190	474,079	453,460	462,147	5,986,998
40	Spion Kop Cost		$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	
41	Prior Year Deferred Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
42															
43	Spion Kop Variable Cost Revenues														
44	NWE Spion Kop Revenues		$ 7,415	$ 7,755	$ 7,102	$ 6,761	$ 7,021	$ 7,704	$ 8,188	$ 7,644	$ 7,226	$ 6,890	$ 6,590	$ 6,717	$ 87,012
45															
46	Subtotal		$ 7,415	$ 7,755	$ 7,102	$ 6,761	$ 7,021	$ 7,704	$ 8,188	$ 7,644	$ 7,226	$ 6,890	$ 6,590	$ 6,717	$ 87,012
47	Prior Year(s) Deferred Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	Total Revenue		$ 7,415	$ 7,755	$ 7,102	$ 6,761	$ 7,021	$ 7,704	$ 8,188	$ 7,644	$ 7,226	$ 6,890	$ 6,590	$ 6,717	$ 87,012
49															
50	Incremental Property Tax Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51															
52	DSM Lost Revenue		$ 5,810	$ 5,810	$ 5,810	$ 5,810	$ 5,810	$ 5,810	$ 5,810	$ 5,810	$ 5,810	$ 5,810	$ 5,810	$ 5,810	$ 69,719
53	DSM Lost Revenue Adjustment		$ 16,791	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,791
54															
55	Subtotal Spion Kop Variable Cost		$ 22,601	$ 5,810	$ 5,810	$ 5,810	$ 5,810	$ 5,810	$ 5,810	$ 5,810	$ 5,810	$ 5,810	$ 5,810	$ 5,810	$ 86,510
56															
57	**Carrying Cost Expense**														
58	Carrying Costs	7.00%	$ 89	$ 78	$ 71	$ 66	$ 59	$ 48	$ 35	$ 24	$ 16	$ 10	$ 5	$ 0	$ 502
59															
60	Total Variable Costs		$ 22,690	$ 5,888	$ 5,881	$ 5,876	$ 5,869	$ 5,858	$ 5,845	$ 5,834	$ 5,826	$ 5,820	$ 5,815	$ 5,810	$ 87,012
61															
62	Deferred Cost Amortization (Under)/Over		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	Monthly Deferred Cost		$ (15,275)	$ 1,867	$ 1,221	$ 885	$ 1,152	$ 1,845	$ 2,343	$ 1,810	$ 1,400	$ 1,070	$ 775	$ 907	$ (0)
64	Cumulative Deferred Cost		$ (15,275)	$ (13,408)	$ (12,187)	$ (11,302)	$ (10,150)	$ (8,305)	$ (5,962)	$ (4,152)	$ (2,752)	$ (1,682)	$ (907)	$ (0)	
65															
66	Variable Rate-Base Deferred														
67	Beginning Balance		$ -	$ 15,275	$ 13,408	$ 12,187	$ 11,302	$ 10,150	$ 8,305	$ 5,962	$ 4,152	$ 2,752	$ 1,682	$ 907	
68	Monthly Deferred Cost		$ 15,275	$ (1,867)	$ (1,221)	$ (885)	$ (1,152)	$ (1,845)	$ (2,343)	$ (1,810)	$ (1,400)	$ (1,070)	$ (775)	$ (907)	
69	Ending Balance Under/(Over)		$ 15,275	$ 13,408	$ 12,187	$ 11,302	$ 10,150	$ 8,305	$ 5,962	$ 4,152	$ 2,752	$ 1,682	$ 907	$ 0	
70															

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.5.33
Annual Spion True-up
NorthWestern Energy

PREFILED DIRECT TESTIMONY

OF CHERYL A. HANSEN

ON BEHALF OF NORTHWESTERN ENERGY

ANNUAL SPION KOP WIND GENERATION ASSET ("SPION") TRUE-UP

TABLE OF CONTENTS

Witness Information

Q. Are you the same Cheryl A. Hansen who filed prefiled direct testimony in the Electricity Supply Tracker portion of this docket?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your Annual Spion True-up testimony?

A. This testimony:

1. Presents the derivation of proposed Spion variable rates for the forecasted 2013-2014 true-up period; and
2. Discusses the overall total supply rates incorporating all individual rate components.

Derivation of Proposed Spion Variable Rates

Q. Please describe the process used by NorthWestern to derive the proposed 2013-2014 forecasted Spion variable rates in this filing.

A. The rate design methodology used in this filing to derive the proposed 2013-2014 forecasted Spion variable rates is the same as that presented for Colstrip Unit 4 ("CU4") and the Dave Gates Generating Station ("DGGS") in previous annual supply filings. All forecasted costs are from Exhibit__(FVB-8)13-14 of the Prefiled Direct Testimony of Frank V. Bennett and are discussed therein.

Derivation of the Spion variable rates is shown on Exhibit__(CAH-5)13-14, page 1. In this filing, the Demand Side Management ("DSM") Lost Revenues associated with Spion for the period December 2012 through June 2013 are included in the 2013-2014 forecasted period; therefore, the 2012-2013 prior period beginning balance is zero. The total Spion variable cost of $87,012 is the sum of incremental property taxes, DSM Lost Revenues (including the 2012-2013 prior period amount), and carrying costs from Exhibit__(FVB-8)13-14. This sum is the amount used to derive the Spion variable rates. The forecasted loads used in the derivation are from Exhibit__(CAH-1)13-14, page 6. The resulting rates are the Spion variable rates proposed in this filing.

Q. Please describe the 2013-2014 Spion fixed rates included in this filing.

A. The Spion fixed cost of service rate components as presented in this filing remain as ordered by the Commission in Docket No. D2011.5.41 and will not change until an order is issued by the Commission in any subsequent revenue requirement filing dealing with Spion.

Page 2 of Exhibit__(CAH-5)13-14 reflects the Spion fixed and variable rates and revenues in summarized format.

Proposed Total Deferred Supply and Total Supply Rates

Q. Please describe the process used by NorthWestern to derive the total 2013-2014 deferred supply rates proposed in this filing.

A. The total deferred supply rate includes three separate rate components – a deferred electricity supply rate, a deferred CU4 variable rate, and a deferred DGGS variable rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(CAH-6)13-14, page 1.

Q. Please describe the process used by NorthWestern to derive the total 2013-2014 supply rates proposed in this filing.

A. The total electric supply rate currently includes several separate rate components – an electricity supply tracker rate, a CU4 fixed cost of service rate, a CU4 variable rate, a DGGS fixed cost of service rate, a DGGS variable rate, a Spion fixed cost of service rate, and a Spion variable rate. These separate rate components are bundled together into a single rate for customer billing as shown on Exhibit__(CAH-6)13-14, page 3.

Q. Does this conclude your Annual Spion True-up testimony?

A. Yes, it does.

Northwestern Energy
Electric Utility Derivation of Rates
Spion Variable Cost of Service
Tracker Period July 2013 to June 2014

Customer Rate Class	Loss Factor	Jul13 to Jun14 Supply Retail kWh Sales	Sales Adjusted for Employee Discount	Sales Weighted by Losses	Spion Variable After Losses kWh Charges	Spion Variable Revenue/Cost Check
Residential	8.5100%	2,356,022,192	2,356,022,192	2,556,519,680	$ 0.000014	$ 32,984
Residential Employee	8.5100%	3,886,619	2,331,972	2,530,422	$ 0.000008	$ 31
GS 1 Secondary NonDemand	8.5100%	279,360,817	279,360,817	303,134,423	$ 0.000014	$ 3,911
GS 1 Secondary Demand	8.5100%	2,477,871,468	2,477,871,468	2,688,738,330	$ 0.000014	$ 34,690
GS 1 Primary NonDemand	5.5400%	563,318	563,318	594,526	$ 0.000014	$ 8
GS 1 Primary Demand	5.5400%	357,213,999	357,213,999	377,003,654	$ 0.000014	$ 5,001
General Service Substation	4.6300%	232,669,987	232,669,987	243,442,607	$ 0.000014	$ 3,257
General Service Transmission	4.0000%	135,701,068	135,701,068	141,129,111	$ 0.000014	$ 1,900
Irrigation	8.5100%	86,094,805	86,094,805	93,421,473	$ 0.000014	$ 1,205
Lighting	8.5100%	57,613,774	57,613,774	62,516,706	$ 0.000014	$ 807
		5,986,998,047	5,985,443,400	6,469,030,933	$ 0.000014	$ 83,795
YNP Contract		19,233,936			Rounding Adjustment	$ 3,218
Total Supply Load		6,006,231,983				$ 87,012
		6,006,232				

2013-14 Spion Variable Cost of Service	**$**	**87,012**
Total Spion Variable COS Rate Before Losses	$	0.000013
Total Spion Variable COS Rate After Losses	$	0.000014

NorthWestern Energy
Electric Utility
Total Spion Revenue ($000) Summary
Tracker Period July 2013 to June 2014

	Jul13 to Jun14 Supply Retail kWh Sales	Spion Fixed: Current Rates[1]	Spion Fixed: Current Rate Revenue	Spion Variable: Proposed Rates 7/1/2013	Spion Variable: Proposed Rate Revenue
Residential					
Residential	2,356,022	0.001047	$ 2,467	0.000014	$ 33
Residential Employee	3,887	0.000628	$ 2	0.000008	$ 0
Total Residential			$ 2,469		$ 33
General Service 1					
GS-1 Sec Non Demand	279,361	0.001048	$ 293	0.000014	$ 4
GS-1 Sec Demand	2,477,871	0.001048	$ 2,597	0.000014	$ 35
GS-1 Pri Non Demand	563	0.001020	$ 1	0.000014	$ 0
GS-1 Pri Demand	357,214	0.001020	$ 364	0.000014	$ 5
Total GS-1			$ 3,255		$ 44
General Service 2					
GS-2 Substation	232,670	0.001011	$ 235	0.000014	$ 3
GS-2 Transmission	135,701	0.001005	$ 136	0.000014	$ 2
Total GS-2			$ 372		$ 5
Irrigation					
Irrigation	86,095	0.001048	$ 90	0.000014	$ 1
Total Irrigation			$ 90		$ 1
Lighting					
Lighting	57,614	0.001048	$ 60	0.000014	$ 1
Total Lighting			$ 60		$ 1
Total Rate Schedule	**5,986,998**		**$ 6,246**		**$ 83.795**
	-				-

[1]Spion Kop Rates (based on 1st yr rev req) approved in Docket No. D2011.5.41 Order No.7159i, effective 12/1/2012.