NorthWestern Energy
Delivering a Bright Future

June 6, 2014

Ms. Kate Whitney
Montana Public Service Commission
1701 Prospect Avenue
P.O. Box 202601
Helena, MT 59620-2601

RE: Docket No. D2013.12.85
PPLM Hydro Assets Purchase
PSC Set 14 Data Requests (305-354)

Dear Ms. Whitney:

Enclosed for filing is a copy of NorthWestern Energy's responses to PSC Set 14 Data Requests (305-354). A hard copy will be mailed to the most recent service list in this Docket this date. The Montana Public Service Commission and the Montana Consumer Counsel will be served by hand delivery this date. These Data Request responses will also be e-filed on the PSC website and emailed to counsel of record.

Should you have questions please contact Joe Schwartzenberger at 406 497-3362.

Sincerely,

Nedra Chase

Nedra Chase
Administrative Assistant
Regulatory Affairs

NC/nc
CC: Service List

CERTIFICATE OF SERVICE

I hereby certify that a copy of NorthWestern Energy's responses to PSC Set 14 Data Requests (305-354) in Docket D2013.12.85, the PPLM Hydro Assets Purchase, has been hand delivered to the Montana Public Service Commission and to the Montana Consumer Counsel this date. These Data Request responses will be e-filed on the PSC website and served on the most recent service list by mailing a copy thereof by first class mail, postage prepaid and will also be emailed to counsel of record.

Date: June 6, 2014

Nedra Chase

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Administrative Assistant
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Docket No D2013.12.85
Hydro Assets Purchase
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NorthWestern Energy
Docket D2013.12.85
PPLM Hydro Assets Purchase

Public Service Commission (PSC)
Set 14 (305-354)

Data Requests served May 23, 2014

PSC-305
Regarding: Future Cap-Ex Reviews
Witness: Rowe

In recommending the Commission reject Dr. Wilson's ceiling on annual capital spending, you argue, "The Commission already has the means by which to properly address these as part of future general rate case prudency reviews," and you then cite to MCA 69-8- 421(9), which discusses the Commission's ability to "disallow rate recovery for the costs that result from the failure of a public utility to reasonably manage, dispatch, operate, maintain or administer electricity supply resources in a manner consistent with 69-3-201, 69-8-419, and commission rules."

a. Suppose that NWE in the future is faced with a large capital expenditure necessary to keep a Hydro running, but which had not been anticipated or budgeted for in this pre- approval docket. In the context of the future prudency review in another rate case which you allude to, would it be reasonable of the Commission to take as evidence of imprudence (or of a failure to "reasonably manage...electricity supply resources") that NWE had failed to anticipate a significant cap-ex event in this docket?

b. If the answer to sub-part (a) is negative, how then does the cited law address Dr. Wilson's concern that capital expenditures which may be prudent and necessary in the future may nonetheless be unbudgeted in this pre-approval docket, thus costing ratepayers unexpectedly more money absent an "imprudence" finding?

RESPONSE:

a & b:

See the response to Data Request MCC-217.

PSC-306
Regarding: Fiduciary Duties to NorthWestern's Shareholders
Witness: Rowe

At 4:12-14 you state you have legal fiduciary duty to your shareholders and the MCC's proposal would not allow you to honor this duty. Staff's understanding is that asset acquisitions of this nature implicate the Business Judgment Rule and that absent waste, bad faith, or gross negligence the purchase of the hydroelectric assets would be considered a business decision generally immune from liability. *See generally* Del. Code Ann. tit. 8, § 141(a); *see also* Smith v. Van Gorkom, 488 A.2d 858, 872 (Del. 1985) ("The business judgment rule exists to protect and promote the full and free exercise of the managerial power granted to Delaware directors").

Please explain the nature of NorthWestern's fiduciary duty to shareholders in this transaction and why NorthWestern does not believe it can meet this duty under the MCC's proposal.

RESPONSE:

I sincerely believe in the long-term alignment of the interests of NorthWestern's customers and its investors. I think this was recognized by Chairman Gallagher's statement, which I quoted in my rebuttal testimony. NorthWestern's fiduciary responsibility to its investors is of crucial importance. We are charged with making prudent business decisions on behalf of our shareholders, who expect a reasonable return on the entirety of their investments, and our debt holders, who expect the entire repayment of debt with interest, while ensuring we have a financially sound utility that can provide safe and reliable service to our customers at affordable rates over the long term. Implementation of the Consumer Counsel's proposal would mean that he and the Commission want NorthWestern to purchase the Hydros from PPL Montana for $870 million, using shareholder capital and debt, and subsequently include the Hydros in electric utility rate base at $682 million. The $188 million difference results in a significant and unacceptable under-recovery of associated costs, including return on investment, return of (depreciation), income taxes, property taxes, etc. Funding of the ongoing cost obligations associated with this $188 million difference would have to be supported from the income of the remainder of the Montana electric utility, putting substantial financial strain on the entire electric utility, NorthWestern, and its customers.

This would not be a prudent business decision and would not meet our fiduciary responsibility to our shareholders, debt holders, customers and other stakeholders, including the Commission and the Consumer Counsel.

PSC-306 cont'd

Would you lend someone $870 million with the knowledge that your investment is only worth $682 million? This is not a rational, sound or realistic proposition. The business judgment rule does not insulate directors from legal exposure for decisions that are obviously neither rational nor sound.

PSC-307

Regarding: Recovery of the Acquisition Premium in Wholesale Rates
Witness: Rowe

In light of an anticipated oversupply of energy during NorthWestern's temporary ownership of Kerr Dam, which will need to be sold on the wholesale market, why didn't NorthWestern seek FERC approval for recovery of the acquisition premium associated with the generation facilities acquired in the proposed transaction in wholesale rates?

RESPONSE:

Surplus wholesale electricity sales are subject to market-based prices under FERC jurisdiction, rather than cost-based rates.

PSC-308
Regarding: Preapproval
Witness: Rowe

a. Would it be fair to say that as a Montana Public Service Commissioner, you had significant concerns when in 2003 the Montana Legislature considered SB 247, which, in its initial form, would have mandated that the Commission make preapproval decisions regarding default supply power purchase agreements? If not, please explain.

b. Would it be fair to say that as a Montana Public Service Commissioner your concerns with preapproving default supply power purchase agreements included shifting risk from the utility to the Commission and consumers, inappropriately placing the Commission in a utility management role, and moral hazard effects? If not, please explain.

c. During your term as a Montana Public Service Commissioner, did the Commission develop default supplier resource planning and procurement guidelines, which persist in substantially the same form today in Admin. R. Mont. 38.5.8201-8229, in order to articulate the Commission's expectations regarding reasonable planning and procurement processes? If so, did you substantially support the rules the Commission adopted?

d. As a Montana Public Service Commissioner, did you vote with the majority in finding that the Commission would not likely have approved 400 MW in default supply contracts NorthWestern presented to the Commission for approval (the Commission found that the Company had not actually acquired the resources because of regulatory out language in the contracts) because NorthWestern failed to apply industry accepted procurement practices, including the use of competitive procurement methods, which the Commission found (agreeing with Dr. Wilson) are the most verifiable way for a utility to identify resource alternatives and acquire competitively priced resources? (See Order 6382d).

e. Other than for purposes of complying with the community renewable energy project requirements of the renewable energy standard, when was the last time NorthWestern issued an all-source competitive solicitation in which it specifically sought offers for long-term (20 years or more) energy and or capacity resources?

RESPONSE:

See the response to Data Request PSC-309 as a preface to the following answers:

a. Yes, as the bill was initially proposed, and in the context of implementation of state supply policy at the time. Subsequently, interested parties participated in informal discussions to better understand the situation and one another's positions and to refine the approach.

PSC-308 cont'd

b. See the response to part a, above.

c. Yes and yes.

d. Yes.

e. NorthWestern has not conducted a solicitation that specifically sought offers for 20 years or more. The question assumes that long-term contracts are generally available for 20 years or more, which is not correct. According to our Supply Group, even shorter term contracts (5 to 10 years) are not readily available without extenuating provisions (e.g., indexed pricing, reopeners, risk premiums, credit support requirements, and/or cost adders).

PSC-309

Regarding: Preapproval
Witness: Rowe

a. Would you acknowledge that NorthWestern's application in this case, much like the Company's application in Docket D2001.10.144 (which resulted in Order 6382d), is substantially about regulatory process, specifically whether it is good regulatory practice for the Commission to preapprove an $870 million, 439 MW capital investment that resulted from a bilateral negotiation that the Commission was not part of and apparently has no ability to shape, given the asymmetric information and moral hazard effects that you previously worried about as a Montana Public Service Commissioner? If not, please explain.

b. Your concurring opinion attached to Order 6382d characterized the majority's decision in that case as "farsighted and courageous." You stated: "Fundamentally, the Commission declined to shift undue risk to default supply customers...." Why wouldn't a decision by the current Commission not to preapprove the Hydro purchase be similarly farsighted and courageous, particularly given that the potential for moral hazard effects may be greater in this case given a profit opportunity that did not exist for the default supplier?

RESPONSE:

a. No. Order No. 6382d was issued in a much different time, place and setting in our energy history. The Order specifically addressed the actions and role of the utility functioning as a Default Supplier in a totally new deregulated energy supply environment. It was based on the circumstances at that time, and the corresponding roles and responsibilities of the entities and individuals involved, including me. I also emphasize, whether then or now, that I do not believe it is the role of the Commission to micro-manage or actively participate in operating the utility business as suggested by the language in this question that refers to a "...capital investment from a bilateral negotiation that the Commission was not part of and apparently has no ability to shape..." It is Montana statutes, rules, and any precedent established by Commission orders that provide the framework that guides utility actions, which is the same framework in which a utility's actions should be judged. The Hydros filing is presented on that basis.

Finally, in NorthWestern's case, as discussed in my Prefiled Direct Testimony on pages RCR-16 to RCR-19, public policy as reflected in statute and rules in Montana today, whether one agrees or not, supports generation reintegration and to that end also allows for preapproval.

PSC-309 cont'd

b. See the response to part a, above.

PSC-310

Regarding: Renewable Generation and Economic Development
Witness: Hines

At 10:1-5 you testify regarding the listening sessions: "Also, many people expressed strong support in having an electric supply portfolio that is comprised of over 50 percent wind and water. People noted that this quantity of renewable generation can provide an immediate inducement for economic development."

Please describe how transferring ownership of PPLM's hydro assets to NorthWestern Energy will induce economic development due to increasing the proportion of renewable energy in NorthWestern's portfolio.

RESPONSE:

As the question PSC-310 states, my testimony is referencing perspectives posited by members of the public and therefore it would be speculation on my part to speak on their behalf. I do recall the public comment on this point was that Montana was potentially a more attractive location for a business to move if the business's energy would be coming from a utility with a substantial percentage of its energy portfolio generated from renewable resources. With the successful acquisition of the Hydros, that representation can be made to potential businesses that would be served by NorthWestern. Also one commenter, a former Montana Department of Commerce director, discussed from his perspective that businesses are frequently interested in the amount or percentage of renewable electricity generation that would potentially be serving them.

PSC-311

Regarding: Governor Inslee's Executive Order
Witness: Hines

a. At 16:4-12 you reference Inslee's Executive Order 14-04 that "...specifically calls on Washington utilities to reduce and eliminate over time the use of electrical power produced from coal, even from those facilities located outside their state." Will this order reduce demand for Colstrip power and provide NorthWestern opportunities to acquire Colstrip energy from Puget, PacifiCorp, and Avista at low market prices?

b. If the Commission rejects NorthWestern's application to preapprove the hydro assets, will NorthWestern inquire into purchasing some of the Colstrip interests of Puget, PacifiCorp, and Avista at low prices to serve a portion of baseload requirements?

c. In offering the state of Washington as an example for the issue of carbon regulation, has NWE considered the full political climate of the state, and whether there are branches of that state's government (e.g., the legislature) which may have countervailing views on this particular issue? Describe NorthWestern's analysis, if it exists, in this respect.

RESPONSE:

a. NorthWestern has no information that if this energy became available that it would be available at "low prices." Given the increasing regulatory scrutiny regarding thermal generation, including greenhouse gas requirements, and as presented in this application, the market price of electricity is forecast to increase. It is reasonable to expect that so long as Colstrip is in operation, the price of power from this facility will be based upon the prevailing market price of electricity, plus any associated carbon adders.

b. NorthWestern has no information that if these assets became available that they would be available at "low prices." During the ongoing regulatory process for the Hydros, NorthWestern is focused on acquiring and integrating the lowest cost/lowest risk resource – the Hydros – into the electricity portfolio. NorthWestern has not considered alternatives.

c. The referenced example, as well as many others, is included in Hines Rebuttal Testimony to illustrate a shift in public policy and/or policy discussion (in a relatively short time period) pertaining to efforts to address future greenhouse gas emissions. NorthWestern has no analysis as requested.

NorthWestern Energy
Docket D2013.12.85
PPLM Hydro Assets Purchase

Public Service Commission (PSC)
Set 14 (305-354)

Data Requests served May 23, 2014

PSC-312
Regarding: Role of NWE in Encouraging Public Comment
Witness: Hines

You rely on public representations in listening sessions to support your application, and to demonstrate that, in your view, "the MCC is out-of-touch with what Montana consumers want" (9:19-20)

a. Has NWE provided talking points, fact sheets, or other documents about the proposed Hydros acquisition in advance to persons who have then provided public comment at PSC listening sessions? If so, provide all such documents.

b. Please describe NWE's efforts to encourage members of the public or representatives of organizations to attend listening sessions and offer supportive comments.

RESPONSE:

The premise of the question is incorrect. NorthWestern did not rely on public representations in the PSC's listening sessions to support the Hydros application. We filed the application in December 2013, long before the MPSC listening sessions to my knowledge were even considered. Rather, as set forth in the Hines Rebuttal Testimony, NorthWestern recognizes that public support for the Hydros is overwhelmingly in favor of the Commission approving NorthWestern's Hydros application.

a. The Commission, in developing and holding the referenced listening sessions, has stimulated a great amount of interest regarding NorthWestern's purchase of the Hydros. Likely due to the Commission's efforts to involve the public in this proceeding, numerous individuals and civic groups, such as Kiwanis, Rotary, and local Chambers of Commerce have invited NorthWestern to discuss the acquisition of the Hydros at their meetings. NorthWestern made formal presentations at some of these discussions; at others it was more focused on answering questions. A number of individuals or groups also discussed with NorthWestern what they could do to support this acquisition. We encouraged them to attend one of the MPSC listening sessions wherein they could provide their perspective. NorthWestern did not keep track of who requested information or who attended the meetings. NorthWestern also informed its employees of the Commission's schedule for the listening sessions and of their right to attend and speak as individuals if they so wished. In addition to NorthWestern's newspaper ads announcing the MPSC sessions, the attached talking points, or subsets of this information, were readily available to NorthWestern employees and likely used to respond to requests for information.

PSC-312 cont'd

b. Please see the response to part a, above.

Here are some suggested topics that may be used to share with others about this potential transaction. It's not necessary, nor do we recommend, that you use this list in its entirety. Please choose the comments that you feel best represent your personal opinions about this transaction. Comments are more effective and more believable when they are stated with words that you normally use and said with the true emotion that you feel, so please feel free to adjust these statements to reflect your personality and style. We greatly appreciate your support of this transaction and encourage you to stay engaged and involved in this very important step towards a brighter energy future for all of our Montana customers.

I support NorthWestern Energy's purchase of PPL Montana's Hydroelectric Facilities in Montana, because:

- This is a unique opportunity to acquire hydroelectric resources that we, as customers in Montana, can rely on to be there for us for generations to come. This is important to customers – it means we will have reliable and stable-priced electricity for years to come.

- It is important to secure these facilities for Montana. We know what happens with our bills when market prices are volatile and we'd prefer to have regulated resources that we can count on to stabilize bills.

- We understand that we are being asked to pay a little more now for these resources. We believe it is a good investment for Montana and are willing to pay a little more in the short-term because of the long-term benefits of owning the Hydros.

- The liklihood of future environmental regulation and therefore higher energy costs is real. The value of the hydros will likely increase over time.

- These assets are obviously for sale. If NorthWestern isn't allowed to buy these assets – someone else will. It will be a tragic loss for Montana. It was a mistake to sell these assets in the first place – don't make a second mistake by allowing these resources to get away from us. NorthWestern's purchase guarantees that these important resources will serve Montana customers and the costs of these assets will be regulated. We have no such guarantee if they are sold to another buyer.

- Hydropower is a clean, stable and sustainable source of electricity. This purchase allows customers to have a dedicated supply of hydropower to meet their energy needs today and for generations to come.

- We believe purchasing the facilities at a fair market price is a prudent long-term decision. It is unlikely that large hydro assets like these will ever be built in the US again.

- Please don't allow this opportunity to secure and own clean, Montana-generated electricity slip through our fingertips just because the price of electricity is lower today. We've played that game before and lost big time.

PSC-313

Regarding: Misrepresentation of Response to MCC-004
Witness: Hines

At 22:2-23:13 you argue that Wilson mischaracterized your response to MCC-004 through emphasizing the value of Colstrip Unit 4 to the utility while you maintain that your response is "clearly focused on the value of the resource to the supply portfolio."

a. Do you agree that Colstrip Unit 4 and other preapproved assets are relevant to this case because these facilities provide opportunities to review the actual performance and portfolio benefits of Commission preapproved assets? Why or why not?

b. Please describe in full the observed benefits that Colstrip Unit 4 has provided to the portfolio since it was rate based in January 2009.

c. Do you agree that electricity provided by Colstrip Unit 4 since January 2009 has been very expensive for NorthWestern's customers when compared to short term market products, including the Mid-C spot market? Why or why not?

d. Regarding the difference in supply cost referred to in part (c), does NorthWestern consider the additional expenditure to be the "price" of rate stability?

RESPONSE:

a. No. The Hydro application should be evaluated and its ultimate disposition should be determined based upon the merits of the Hydros in the context of meeting the future needs of the electricity portfolio.

b. Colstrip 4 has provided necessary on-system baseload power to the portfolio.

c. No, I do not agree. It is not appropriate to compare spot prices over a short period to the investment in a long-term generating asset.

d. No. Please also see the response to part c, above.

PSC-314

Regarding: Misrepresentation of Response to MCC-004
Witness: Hines, parts a & c / Barnes, part b

a. Should the Commission be concerned that although it preapproved NorthWestern's 222 MW share of Colstrip Unit 4 at more than $400 million in 2008, in 2013 NorthWestern valued PPLM's 222 MW share at Colstrip Unit 3 at $100 million? (See spreadsheet response to PSC-066). Why or why not?

b. Please provide NorthWestern's supply customers share of the total production at Colstrip Unit 4 that has been lost in unplanned outages since January 1, 2009. How was the potential loss mitigated by the reciprocal sharing agreement with PPLM?

c. Assuming PPLM is successful in selling its 222 MW share in Colstrip Unit 3, will this affect the reciprocal sharing agreement? If so, how will this affect the dependability of the Colstrip Unit 4 resource?

RESPONSE:

a. Please see the response to Data Request PSC-313a.

b. The Reciprocal Sharing agreement with PPL (or successors) causes each party to act as a 15% Project Owner in Colstrip Units 3 & 4. As such, each party is entitled to take up to 15% of the available output from each unit. Given the preceding context, perhaps the best way to answer the question is by listing the Equivalent Availability Factor ("EAF") and the Forced Outage Factor ("FOF") for each unit for each year requested. The data is presented in the table below. For further context, EAF is the portion of time a unit is available to operate and FOF is the portion of time the unit was shut down for emergency reasons or a condition in which the generating equipment is unavailable for load due to unanticipated breakdown. Differences between the total of EAF and FOF and 100% is the percentage of time the Unit was off line for planned maintenance outages.

PSC-314 cont'd

	Unit 3		Unit 4		Combined	
	EAF	FOF	EAF	FOF	EAF	FOF
2009	95.92%	1.14%	40.65%	45.83%	68.29%	23.48%
2010	94.37%	3.04%	95.88%	2.44%	95.12%	2.74%
2011	72.92%	10.98%	95.52%	2.78%	84.22%	6.88%
2012	89.25%	1.34%	96.27%	1.87%	92.76%	1.60%
2013	96.61%	1.63%	34.94%	52.20%	65.77%	26.91%
Average	89.81%	3.63%	72.65%	21.02%	81.23%	12.32%

c. To my knowledge, no, and it will not affect our expected output from Colstrip Unit 4. NorthWestern does not believe this question relates to the Hydros application.

PSC-315

Regarding: Chart 2
Witness: Hines, p. 8

a. If NWE has prepared a chart similar to Chart 2 that shows residential customer electricity costs for the period 1999 through 2013, please provide it.

b. Please provide the residential customer data used to create Chart 2, in Microsoft Excel format if possible.

c. If NWE provided the chart requested in part (a) of this data request, please provide the residential customer data used to create that chart, in Microsoft Excel if possible. Otherwise, if NWE has residential customer data of the type used to create Chart 2 for time periods after 2008, please provide those data through the most recent time period available, in Microsoft Excel format if possible.

d. If NWE has projections of residential customer data of the type used to create Chart 2 for future time periods, please provide those projections, in Microsoft Excel format if possible.

RESPONSE:

a. NorthWestern has a draft of such a chart. It is provided in the folder labeled "PSC-315" on the attached CD.

b. See the response to part a, above.

c. See the response to part a, above.

d. See the response to Data Request PSC-351. Also see pages 2 through 4 of the Stimatz Rebuttal Testimony.

PSC-316
Regarding: Carbon Risk
Witness: Hines, pp. 14-15, part b / Fine, part a

a. Please provide the carbon cost scenarios NWE modeled in its 2005 and 2009 resource plans (the plans typically provide these scenarios in tables that show the annual cost of carbon emissions that are used to develop market price and resource cost adjustments). Please provide this information in Microsoft Excel, if possible.

b. Please provide documentation to support the examples of Pacific Northwest thermal plants expected to shut down over the next decade.

RESPONSE:

a. See the folder labeled "PSC-316" on the CD attached to PSC-315.

b. Please see Attachment, page 5.

Clean Air Act Section 111(d) CO2 Reduction Compliance Pathways for the Pacific Northwest and Intermountain West States

Angus Duncan

For the Natural Resources Defense Council

March 31, 2014

White Paper

Clean Air Act Section 111(d) CO2 Reduction Compliance Pathways for the Pacific Northwest and Intermountain West States[1]

Abstract

The paper describes the architecture of a regional electric grid extending across nine[2] Intermountain West and Pacific Northwest states, characterized by coal-fired generation on the east and south serving loads across the region including states to the west with few or no coal facilities but with significant loads and energy efficiency opportunities. This multi-state arrangement argues for an EPA Clean Air Act 111(d) strategy that calculates a Best System of Emissions Reduction (BSER) standard on a regional basis, then disaggregates and allocates reduction obligations to individual states and the emitting generating units therein. Voluntary State-to-State agreements could then identify least-cost[3] compliance strategies involving single or multiple shared facilities in one or more states. Such strategies might continue full plant operations at the most efficient plants in "producer" states, reduced output from or retirement of less efficient units, and replacement of lost generation with a least-cost portfolio of low-carbon resources in both "producer" and "consumer" states. The desired outcome is overall regional "system" emissions that are in compliance with an EPA-set emissions standard for the region overall.

[1] This paper was written by Angus Duncan for NRDC, in consultation with these Pacific Northwest and Intermountain West regional organizations: Climate Solutions; Environment Oregon; Environment Washington; Idaho Conservation League; Montana Environmental Information Center; Northwest Energy Coalition; Powder River Basin Resource Council; Renewable Northwest Project; Sierra Club; Snake River Alliance; Utah Clean Energy; Washington Environmental Council; Western Resource Advocates.

[2] AZ, CO, ID, MT, NV, OR, UT, WA, WY all have coal plants serving PNW/IW loads (see also page 4); coal-generation is also imported at times from NM, TX and other states in lesser amounts.

[3] "Least-cost" as the term is used in the Northwest Power Act of 1980 to include all costs and benefits, including environmental costs and benefits, whether monetized, quantified or described, and whether presently internalized or externalized.

Problem Statement

The Obama Administration proposes to regulate greenhouse gas (GHG) emissions from existing power plants with the objective of reducing those emissions over time consistent with the nation achieving an overall GHG emissions reduction goal of 17% below 2005 levels by 2020. The Environmental Protection Agency (EPA) plans to use Section 111(d) of the Clean Air Act (CAA) to develop a rule by mid-2015, and require state compliance plans one year later. Those plans will either adopt EPA-issued "best system of emissions reduction" (BSER) guidelines, or gain EPA approval of State plans as resulting in equal or greater reductions.

EPA is likely to afford substantial flexibility to States and plant owners in developing compliance plans, including allowing a "systems-based" approach under which emissions from two or more plants can be aggregated and averaged across the system counted for compliance. EPA is also considering how new, low-carbon supply- and demand-side replacement resources can count toward compliance [to the extent they displace real emissions within the system subject to compliance requirements].

Interstate electricity sales will complicate this regulatory structure. It is not clear what compliance pathways will be workable for states whose utilities import significant quantities of power from coal-fired generation[4]; and for states containing significant coal-fired generation that export to loads in other states. Reconciling state-by-state compliance plans with this utility architecture – which is especially typical in the Pacific Northwest and Intermountain West states – will be challenging.

At its most basic, the task is simply stated:

> (1) What emissions reduction trajectory for existing thermal power plants serving this region is consistent with the requirements of the Clean Air Act (including cost consequences); and,
>
> (2) How will the costs of compliance be allocated among plant owners and power consumers?

EPA can perform the calculations to arrive at the first; and utility regulators have tools to achieve the second (not without some wrangling), including in circumstances where plants and loads are distributed among two or more states. An EPA 111(d) rulemaking process could choose to stop here.

The harder, third task is not a legal requirement, but it is essential to undertake if the outcome, for the the region, is the appropriate emissions reduction that is also politically achievable:

> (3) What's a *least-cost* compliance pathway for customers of affected utilities, and for affected states facing community, employment and tax effects of potential plant cutbacks or closures?

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[4] The reverse complication may exist for a state that imports substantial quantities of low-carbon power (e.g., hydro; wind; nuclear) and finds that EPA attributes higher carbon content to it based solely on in-state generation.

A lower cost pathway would rely on wider portfolio of energy efficiency, renewable resources and integrating resources outside the plant fenceline as replacement resources for reduced or terminated coal-fired generation. The compliance role for such resources is to replace such generation and its associated emissions.

EPA's summer 2014 draft rule needs to be written with the flexibility to allow such least-cost pathways, and with a framework that encourages states and utilities to devise and propose them.

While the CAA does not contain a direct legal obligation to seek a least cost path, there are reasons to do so that should be compelling to all parties. The first reason is that EPA is obliged to consider cost when setting a performance standard (in effect, the benefits of the regulation must outweigh the costs imposed by the regulation; see "111(d) Regulatory Process," below). That test is expansive, allowing EPA to include both immediate and downstream societal costs and benefits, not just the transactional costs to the plant owners and their customers. But it can mean only minor emissions reductions are obtained, especially from technical fixes at the power plants themselves. In contrast, EPA guidelines that – by virtue of their wider choice of allowable compliance paths – result in lower costs to plant owners and their power customers, are more likely to invite cooperative efforts among producer states, consumer states and utilities to devise cooperative compliance strategies.

The optimum outcome, toward which EPA and those supporting an effective rule must bend their efforts, is the one that achieves material emissions reductions at costs that stay carefully within CAA limitations.

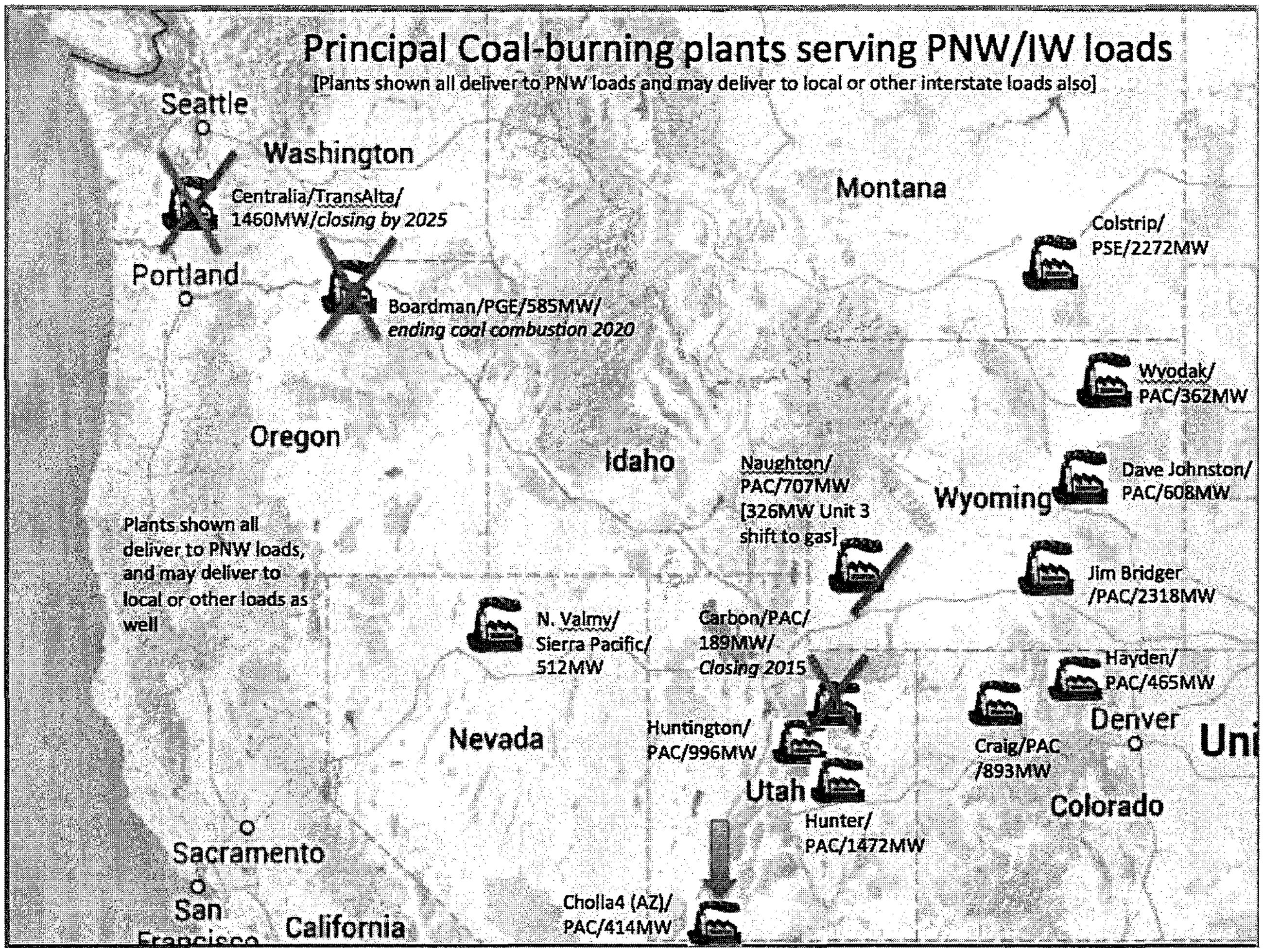
The Pacific Northwest / Intermountain West Electricity System

This challenge is especially complicated in the Pacific Northwest and Intermountain West, where a substantial part of the load lies along the I-5 corridor (the Seattle and Portland metro areas), while most of the coal-fired generation imported to serve these loads is located in Montana, Wyoming Nevada and Utah; and most of this generation in at least Montana and Wyoming is committed to out-of-state loads[5]. The respective coal-generation capacities are[6]:

[5] The largest shares of the WY and MT capacities and costs shown are allocated to out-of-state loads, but that share by state will vary with utility ownership share, the location of that utility's loads, seasonal load variability and market conditions. Some facilities in Colorado, Arizona, New Mexico and Nevada also export to out-of-state loads in this PNW/IW region; and all of the region's utilities purchase "system power" that may originate in coal or other power plants across the western grid.

[6] Plant capacity values may be stated slightly differently in different documents and proceedings.

Montana	2717 MW
Nevada	521 MW[7]
Oregon	585 MW
Utah	5204 MW
Washington	1460 MW
Wyoming	4627 MW
Arizona	414 MW



This difference becomes greater still in 2020 (when coal combustion ends at Boardman and one Centralia plant) and 2025 (the other Centralia plant is retired)[8]. Neither Oregon nor Washington will then have

[7] This is the North Valmy power plant, 50% owned by Idaho Power which imports generation into the PNW. Nevada has one other coal facility – Reid Gardner Station, 612 MW – that will be fully closed, in response to state regulatory action, by 2017.

any coal combustion remaining within their borders; and Idaho already is coal-free. Yet all three will remain in significant degree[9] dependent on imported coal generation to meet loads.

The largest share of the remaining coal plants in the region is owned by PacifiCorp (PAC), but substantial shares in certain plants are divided up among multiple owners[10] and serve loads in multiple states, complicating decision-making. The plants also have different useful life designations. All regional coal plants 40 years and older belong to PAC. The selection of a baseline from which coal emissions reductions are measured, and the level of reductions required in each state under the rule, will affect plant owners differently, but PAC stands to be most challenged because of the makeup and age of its fleet, and because it operates (generates and serves loads) in multiple states.

While this discussion centers on the coal assets of investor-owned PNW/IW utilities[11], there are also some 130 consumer-owned utilities in the PNW and more in the IW. Most COU's are served from their own resources or from the federal hydropower system through the Bonneville Power Administration or Western Area Power Authority, and are unlikely to be significantly affected by an EPA carbon rule. In addition there are both merchant coal plants (e.g., Centralia) and coal units owned and operated by other utilities but delivering power into the PNW grid, which will be accounted for in an EPA rulemaking. To make this already complex subject slightly less complicated, this paper excludes these facilities. State air regulators will need to deal with them however, and it is possible they could be wrapped into a system compliance strategy to collective benefit.

Planning is further complicated by other Clean Air Act regulatory proceedings underway[12] to which different plants have different exposures; and by price pressure from growing new sources of natural gas and declining cost curves for renewable technologies.

Much of the region's long-distance transmission mileage is dedicated to east-to-west movement of power from these coal plants[13], and the economics of this transmission is substantially intertwined with the

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[8] If EPA sets a baseline year earlier than 2020, both OR and WA will likely be in compliance with any EPA existing power plant rule, and might even have reduction "credits" to trade to out-of-compliance facilities and their owners. Electricity customers in all three "in-compliance" states will still be financially responsible for plants located elsewhere but serving their needs.

[9] After 2020, coal's estimated share of load in WA will be around 15%; in Oregon, around 25%; and in Idaho, over 35% (per ID 2012 Energy .Plan)

[10] e.g., Colstrip/2272 MW; shares in four units owned variously by Puget Sound Energy, Portland General Electric, Avista, PacifiCorp, Northwestern and PPL Montana. Similarly, 2/3 of Jim Bridger/2318 MW is owned by PacifiCorp and the balance by Idaho Power.

[11] E.g., the Investor-Owned Utilities in footnote 9 above.

[12] e.g., regional haze, SO2/Nox, water, particulate, ash waste, mercury, and the downstate transport rule

[13] Substantial transmission capacity in Oregon/Washington and from northwest Montana and Canada south and westward is used for hydroelectric generation

destinies of these facilities as well as with any replacement resource strategies for displaced coal generation. How interstate sales and deliveries of energy are treated with respect to emissions liabilities will be critical to the calculations for each state and utility involved in these transactions, and their effects on utility determination of least-cost replacement resources, future energy contracts, and transmission investments and management of existing assets.

Dramatis Personae

The Power Plants: There are thirty coal-fired power units at fourteen plant sites across eight states[14], with a combined nameplate capacity of 15,528 megawatts (see attached table), in part or fully committed to serve loads in the Intermountain West and Pacific Northwest[15]. After coal combustion ends at the Boardman, Centralia and Carbon facilities, and another plant (Naughton 3) is converted to gas combustion, some 12,968 megawatts of coal-fired generation will, under current plans, continue to operate. Eight units, all owned by PAC and comprising almost 1400 megawatts , are now 40 years or older and relatively inefficient (with heat rates well above 11,000 BTU/kWh). Most of the region's older units will require additional pollution controls to comply with the CAA before CO2 emissions come into play, but the extent of their obligations vary with each plant.

The Utilities: Two-thirds of the residual (post-2025) regional coal capacity is owned and operated by PAC, making it by far the largest owner and operator of these facilities. Puget Sound Energy (PSE) follows with around 8%. Portland General Electric (PGE), Avista, Idaho Power, Northwestern, Sierra Pacific and PPL share ownership in the balance of the aggregated plant capacity[16]. Some utility service territories are wholly contained within a state (e.g., PSE, PGE) while others may have territories and customers across two or more states (e.g., PAC; Avista; Idaho Power)[17].

The Air Regulators: EPA regulates emissions at power plants, generally operating through State air and water quality regulatory agencies and requiring State rules to be equal to or more rigorous

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[14] PAC has customers in six states: OR, WA, MT, WY, UT and CA. It owns coal generation (or shares) in MT, WY, UT, CO, AZ, and NM. . I

[15] Apart from plants largely dedicated to PNW loads, coal dependence varies from year to year with each utility and may vary with available hydropower supplies and sales/purchases of system power, some of it coal-generated, from western power markets.

[16] There are also over 130 consumer-owned utilities (COU's) in the four PNW States (OR, WA, ID, MT) and more in the other producer states; but very little coal-generated electricity is delivered to the PNW ConCOU's. Some IW COU's own substantial coal-generating assets, but these COU's are not considered in this case study.

[17] Centralia is a merchant plant privately owned by Trans-Alta Corporation. As such its operations come under FERC regulation but it is not subject to state utility commission rate-of-return regulation. This is also true for the PPL merchant plants in Montana, and for all COU-owned facilities.

than EPA guidelines. Prevailing federal regulation for these plants include: ozone, SO2/Nox, water, particulate, ash waste, mercury, and the air transport rule (for downwind effects of plant emissions). Depending on when plants were built or underwent major modification, and whether an owner has systematically installed emissions control systems or was able to defer certain retrofits under "new source" exemptions, different rules will apply differently. EPA either approves state compliance plans or, if necessary, will develop and impose a federal compliance plan.

The Utility Regulators: Each State has a public utility regulatory commission that authorizes rates of return, customer tariffs, and terms of recovery of capital investment for each investor-owned utility with an assigned service territory. These commissions also review the resource planning and capital investments made by their regulated utilities, including investments made to comply with Clean Air Act and other regulatory requirements. Utility regulators have no air quality regulatory authority but must address cost allocation resulting from rules set by air regulators, so they are likely to be closely consulted on cost implications of different emissions regulatory approaches. They oversee cost recovery on utility capital investments; and measurement of energy efficiency gains, a critical task in the process of capturing least-cost emissons reductions. They also oversee utility Integrated Resource Planning (IRP's) where each utility will need to describe its 111(d) compliance strategy and the effects on its generating facilities and costs. PacifiCorp has customers in six states, making for an especially challenging utility regulatory task as each regulatory body has authority to make decisions independent of the other five. The states have over time developed tools for allocating PacifiCorp costs among them, although each may allow or disallow recovery of different costs. The formulas demand regular review among the utility and the six commissions, to work through disagreements that may advantage or disadvantage one state and the customers therein. The good news is that much of the necessary allocation methodology and mechanisms exists; the challenge is that allocating the costs and emissions reduction responsibilities from 111(d) compliance can be expected to place new stresses on these arrangements.

The 111(d) Regulatory Process

There are extensive writeups (and differing interpretations) of the contents and meaning of the CAA Section 111(d)[18] and how it may be applied to GHG emissions from existing power plants[19], which will not be repeated here. But a brief introduction to 111(d) will serve to delineate some of the critical choices facing utilities,

[18] The text of Section 111(d) is attached to the Paper. Previously, EPA has applied S 111(d) to plants producing sulfuric acid, phosphate fertilizer, aluminum, and paper pulp; and to municipal solid waste landfills.
[19] See: NRDC; EDF; Brattle Group, Georgetown Climate Center

regulators and citizens of the Pacific Northwest and Intermountain West. From a September 2013 EPA memorandum[20] on the subject (critical terms underlined):

> "[President Obama's June 25, 2013] Memorandum directs EPA to issue proposed carbon pollution standards and guidelines, as appropriate, for modified and existing power plants by no later than June 1, 2014, and to issue final standards and guidelines, as appropriate, by no later than June 1, 2015. In addition, it directs EPA to include a requirement for state submittal of the implementation plans required under section 111(d) of the Clean Air Act by no later than June 1, 2016.
>
> Under section 111(d) EPA issues guidelines for states to use in developing plans implementing standards of performance for the affected sources.
>
> "Section 111(d) of the Clean Air Act is broad and allows for collaboration between EPA and states to address pollutants that endanger the public health and welfare. Moving forward, there are different options available for addressing carbon pollution from existing power plants such as a "source-based approach" and a "system-based approach." A source based approach evaluates emission reduction measures that could be taken directly at the affected sources—in this case, the power plants. A system-based approach evaluates a broader portfolio of measures including those that could be taken beyond the affected sources but still reduce emissions at the source.
>
> "EPA believes that its guidelines should identify for sources and states the required level(s) of performance prior to plan submittal. Under section 111:
>
>> *"Standard of performance" means "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."*
>
> "There are a number of ways to reduce CO_2 emissions from existing power plants that might be included in an evaluation of the best system of emission reduction (BSER), including:
>
> - Onsite actions at individual affected section 111(d) sources.
>   - Supply-side energy efficiency improvements ("heat rate improvements").
>   - Fuel switching or co-firing of lower-carbon fuel.
> - Shifts in electricity generation among sources regulated under section 111(d) (e.g., shifts from higher- to lower-emitting affected fossil units).
> - Offsite actions that reduce or avoid emissions at affected section 111(d) sources.
>   - Shifts from fossil generation to non-emitting generation.
>   - Reduction in fossil generation due to increases in end-use energy efficiency and demand-side management."

[20] See EPA: "Considerations in the Design of a Program to Reduce Carbon Pollution from Existing Power Plants"

Critical Terms for a Regional Compliance Strategy

How the following terms are defined in practice by EPA will be critical to the design of an effective regional compliance strategy. It should be understood that the definitions are likely to be the subject of legal actions by both regulated parties and other stakeholders.

"rate-based / mass-based emissions values": There are indications EPA is likely to propose a rate-based standard – pollutant quantity emitted by a facility per unit of output (lbs/MWh) – for application in each state, and apply this at the point of plant emissions. On a system (state or utility) basis, it is possible for a rate-based value to be converted to a mass-based value (total lbs. GHG emissions within a state, or from a utility system of plants) allocated among plants or accountable parties. EPA would need to determine the mass-based reduction amounts, then convert back to a rate-based value to compare outcomes and ensure compliance.

"source-based approach / system-based approach": A source-based approach is generally understood as a strategy that controls emissions at a single source, e.g., a single power plant. While there are often efficiencies that can reduce GHG emissions at the margin, in many cases they may be of limited effectiveness or more costly than available alternatives. A source-based approach may struggle to bring significant reductions at costs consistent with EPA guidelines. A system-based approach, on the other hand, may permit a state or utility to aggregate multiple power plants (e.g., all power plants within a state; all power plants within a utility across a state, or across multiple states) within a plan, backing off power production (and emissions) at some plants and averaging these with other plants that continue to operate at higher capacity factors. A system-based approach might permit a multi-state emissions management structure like an ISO[21], or like RGGI[22], to aggregate and average emissions across multiple plants owned by multiple operators. The advantage of a system-based approach, of course, is that by being selective about which plant operations will be reduced and replaced by lower-carbon options, and which may continue to be operated at higher capacities, facilities can be managed to optimize power operations for CAA compliance at the least cost.

"Standard of Performance; Best System of Emissions Reduction (BSER)": EPA is expected to establish a Standard of Performance either for individual plants (source-based) or an aggregation of plants (system-based). In either case it has an obligation to identify a BSER and issue guidelines for State implementation of the Standard that employs the BSER or another approach that yields equal or better emissions outcomes. Given the complex and interacting architecture of the power system, it is

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[21] Independent System Operator, refers to an agency managing electrical system and grid operations in a state or region that has substantial private wholesale power suppliers

[22] Regional Greenhouse Gas Initiative, an operating multi-state carbon cap and trade arrangement involving nine states in the US Northeast.

arguable that a BSER could *require* a systems-based approach, since a source-based approach is highly likely to result in substantially higher emissions and costs both.

"State Implementation Plan": EPA is expected to issue its Standard of Performance and compliance guidelines for States in mid-2015. States will develop implementation plans for submission to EPA by mid-2016. For states that fail to submit plans or fail to get them approved, EPA will develop a Federal Implementation Plan and require the state to adopt and execute it. For a systems-based approach that involves more than one state, it is likely that EPA will require approved implementation plans from all involved states.

A Systems-Based Strategy for the Pacific Northwest/Intermountain West

Given the dispersed nature of the regional electricity system, and the geographical separation of generation and loads across nine states[23], EPA's rule-writing options are complicated. While generation and load are spread across what is truly a regional electrical system, there is no regional transmission authority or independent system operator (e.g., CAISO or PJM). A region-wide, multi-state pact like a RGGI is unlikely given the limited time for developing state compliance submissions to EPA, and the highly divergent views among the PNW and IW states on the threshold question whether GHG reductions are even necessary[24].

Still, options exist for a least-cost system-based approach that the states and utilities may see in their best interests, albeit for different reasons.

When devising a least-cost reduction strategy, bear in mind that there are three categories of costs to be evaluated:

1. Cost of emissions reduction retrofits at plants subject to compliance, if proposed. These may be as costly as carbon-capture-and-storage[25] (CCS), or as relatively modest as efficiency improvements in plant and transmission operations.
2. Cost of replacement resource for the reduced or terminated output of a power plant subject to the regulation. Resources may include generation (e.g. wind or other renewable resources, baseload gas turbine, peaking/integrating gas turbine), storage (e.g., utility-scale batteries, underground compressed air storage), and demand-side resources (e.g., energy efficiency, and demand-response

[23] See Footnote 2.

[24] The option of joining an existing aggregation like RGGI, or California's AB 32 cap-and-trade, present their own complexities; this is especially so given the interdependence of PNW/IW consumer and producer states, possibly requiring that most or all agree to such an affiliation. The option of rolling up state-to-state agreements into a larger regional aggregation likely would remain viable and could be accessed, post-EPA rule, by willing state governments.

[25] CCS is most likely to be a cost-effective emissions reduction strategy in limited applications at power plants where the carbon dioxide can be piped to nearby oil fields and used to increase oil recovery in older well fields.

integrating resources such as electric vehicle batteries). Generally, energy efficiency has been the region's lowest cost resource, but it is unlikely to be the only resource selected to replace coal combustion[26]. Capturing energy efficiency in one state and using it to reduce plant operations and emissions in another state will require some deft agreement-writing and EPA oversight flexibility, or the development of a tradable allowance system.

3. Cost to communities of impacts attributable to reduction in coal plant operations or plant shutdown. These may include lost jobs (and related multiplier effects on local businesses), and lost tax revenues.

Of course there are real and potential offsetting benefits that may be realized under a well-designed compliance approach. States that are net importers of coal-generated power, like ID, OR and WA, should see a reduction in dollars exported out of state to pay for those imports (e.g., over $300mm annually in fuel and operations costs alone for OR alone[27]). Substituting efficiency and renewable generating resources for coal generation will result in new jobs, additional environmental benefits, potentially lower electricity costs long-term (as hydropower has delivered over the last century) and an accelerated transition to the more flexible and distributed power (and electric vehicle transportation) systems of the future[28].

There are many possible combinations of state compliance plans and utility actions, within a single state's boundaries or involving more than one state. The most often discussed may be summarized as follows:

1. Plant-by-plant emissions reduction[29]: EPA may simply begin by allocating emissions reductions (or maximum allowed emissions) for each power plant subject to regulation. Enforcement at the plant would be direct and straightforward, but limited options for such direct reductions are likely to result in higher costs and therefore lower reductions.

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[26] For example, generating power plants are needed across the system to maintain voltage support and other power quality conditions within the transmission system. Note: energy efficiency capture in OR and WA is already keyed to a cost-effectiveness test involving combined cycle gas generation, likely the same test that would be applied in gauging efficiency replacement resources available for reduced coal combustion.

[27] per communication from Phil Carver, Oregon DOE, based on utility filings described in FERC Form 1 for 2012.

[28] per Synapse Energy Economics Inc., quoted from NRDC Issue Brief "Less Carbon, More Jobs, Lower Bills", July 2013.; shows Oregon adding 1900 job-years and lowering the average utility bill by $0.65/month; and Montana adding 3600 job-years while lowering the average utility bill by $1.25/month (added jobs largely in energy efficiency). NRDC's 2014 update of the analysis reflects declining real costs of renewable generating technologies and of gas, and shows still greater reductions with accompanying greater benefits, at lower compliance costs ("Cleaner and Cheaper: Using the Clean Air Act to Sharply Reduce Carbon Pollution of Existing Power Plants, Delivering Health, Environmental and Economic Benefits", NRDC 2014).

[29] A "plant" may be a single coal burning power generation unit, or it may be a facility containing two or more such units (e.g., the Colstrip facility has four generating units that can each operate independently of the others, and that has its own shared ownership.

2. State-by-State emissions reduction: For each state, EPA could aggregate rate-based, plant-specific reductions, convert to a mass-based value, and allow (or require) a State to propose a strategy for achieving the indicated reductions. The State could then develop with in-state plant owners a strategy for allocating reductions among the plants according to a least-cost or other methodology (that includes replacement resources and their associated emissions). .For the PNW, this approach leaves unclear the relationships between producer and consumer states. On the one hand, customers in consumer states would have an obligation to pay for replacement costs, but limited access to the emissions reduction levels and the resource replacement assumptions used by the air regulators in the producer states as the basis for setting emissions reduction levels and compliance determinations[30]. On the other hand, the producer states may have difficulty accessing lower cost efficiency resources for a replacement strategy since loads (and thus efficiency opportunities) would be in another state not bound by EPA to perform. Together, a producer state and a consumer state can jointly shape a single least-cost strategy to which each contributes, and for which the range and extent of compliance options is wider than would be available to either alone.

3. Regional Agreement: A regional agreement for the PNW states might be similar to RGGI. It could involve power plants and customer loads across the nine state area. It could convert EPA rate-based values – calculated assuming, as a BSER, an efficient regional system acting to capture maximum obtainable reductions -- to an aggregate regional mass-based value. The States could then use an allocation agreement or allowance system to assign reduction (and resource replacement) responsibilities. For compliance, reductions would be totaled and disaggregated among the states, who would then report separately to EPA. So long as the total reductions matched EPA's requirements, the states would be in compliance. Issues with this approach include: the short time period between when an EPA rule is published and when state compliance plans need to be in place, including any such regional arrangements; institutional and political differences among the nine states; absence of a regional ISO or other institution that could help manage transactions.

4. Bilateral or Multilateral State-to-State Agreements: An alternative to trying to assemble a regional approach up front, that could capture much of the least-cost value of collective regional action, might be a series of bilateral State-to State agreements developed around a single plant or multi-plant facility. As above, EPA would calculate a BSER value for the region, develop plant-specific rate-based values, and provide the methodology for converting to plant- or unit-specific mass-based values. Regulators in the producer and consumer states, together with the unit's owner,

[30] Actual resource replacement decisions would be made by the utility involved, overseen by the utlity regulators in the consumer states.

could negotiate a strategy for that unit's compliance that might include both complementary arrangements with other plants and owners and/or reductions in plant operations coupled with development of lower-carbon replacement resources. Such bilateral agreements could work off a common model agreement that is replicable state to state, and that subsequently could be rolled up into more comprehensive multi-plant agreements (and, logically, a voluntary regional agreement over time).

Example: A PNW/IW Multi-lateral Compliance Agreement

For illustrative purposes, the following describes how one such multi-lateral arrangement might be structured to involve three parties collectively seeking to devise a least cost compliance strategy: (a) a "producer state" with 111(d) compliance responsibilities (e.g., MT; WY); (b) a "consumer state" (e.g., OR, WA); and, (c) a utility[31] with a power plant in the first state and much of its load in the second. Thus . . .

Step One: After consultation – and optimally -- EPA develops a BSER based on obtaining emissions reductions from the PNW utility system considered as a single system involving nine states, then disaggregates the required reductions by state and plant unit[32]. Some states are primarily consumer states (OR; WA; ID), some primarily producer states (MT;WY), and some (UT) mixed. This analysis assumes that, once a BSER is established, it is to all parties' advantage to seek a least-cost compliance solution and that costs can be allocated equitably within the system. EPA would establish how reductions would be measured and verified[33]. EPA would then invite but not obligate states and utilities to find cooperative means to achieve the reductions, develop replacement resource plans, and allocate costs. The states and utilities could use the system modeled by EPA in setting the trajectory, or select an alternative strategy – including options that traded emissions reductions among utilities and within or across state lines – so long as the overall regional reduction trajectory is realized.

Step Two – Example A: Two states enter into a bilateral agreement that involves a producer state and a consumer state, linking the plant(s) and loads of a utility that owns and operates plants in the producer state. Thus, WA and MT enter into an agreement, to which Puget Sound Energy (PSE) is party as the implementing utility, by which PSE's share of allowable emissions at the Colstrip

[31] . . . or two or more utilities sharing ownership of the same power plant, with customers in different service territories (and potentially, more than one consumer state)

[32] EPA could also calculate a BSER based on a different "system" -- e.g., of generating units within a state, or within a utility – then set emissions performance standards based on that system analysis.

[33] E.g., EPA could establish an overall multi-state/system GHG emissions limit on a mass basis, then convert this to an intensity-basis for each plant. For compliance measurement, EPA could convert plant intensity values, averaged, back into a mass-basis value and compare to the multi-state BSER value.

powerplant (four generating units) is set consistent with the EPA rule (and proportionate to PSE's share of the required Colstrip reduction). The lost resource is replaced with a least-cost combination of load-center energy efficiency measures (in WA, where the PSE load is), plus wind energy and wind-integrating resurces/storage in WA, MT or elsewhere. If other utilities that also have shares of the Colstrip units also propose to reduce plant output (or close one or more units of the facility), Montana may seek to negotiate agreements with all involved states and utilities to ensure that a substantial share of the replacement resource is sited in Montana to offset employment and tax revenue losses, and resulting community impacts, as well as use otherwise-orphaned east-to-west transmission assets.

Step Two – Example B: For a utility such as PacifiCorp (PAC), with multiple plants across two or more states, a system least-cost pathway may involve backing down or shutting down the least efficient plants and continuing to operate the most efficient, across state boundaries. If this results in disproportionate reductions in one state (e.g., the least efficient plants are disproportionately in one state), an emissions liability sharing agreement could be negotiated among two producer states (MT; WY) and, a consumer state (OR), allocating costs across utility (PAC) customers[34], that supports a least-cost resource replacement strategy.

Step Three: Compliance plans, emissions reduction allocations and cost allocations are reported by each plant owner (or partial owner) to its state air and utility regulators. State air regulators validate the emissions reductions achieved (or proposed to be achieved) in each state, and report to EPA which reaggregates and compares to its adopted trajectory (BSER. Utility regulators would review and acknowledge[35] the proposed replacement resource plans consistent with existing practices. Cost allocations among the states would be handled, as now, in separate proceedings.

In each of these cases, EPA has *calculated* system emissions reductions across a system, then *disaggregated* these emissions reductions and *allocated* them by state. The states and utilities are then enabled to find least-cost compliance solutions that permit and encourage, but do not require, re-aggregation into "systems" through a series of manageably-sized, mostly trilateral agreements (two states, one utility-owned power plant) that allow costs of resource replacement and local impacts to be negotiated among the direct parties.

The three tasks set out at the beginning of this paper have been addressed:

- Task 1, setting the BSER emission outcomes, by EPA;
- Task 2, identifying and negotiating a system-based least-cost compliance strategy; and,

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[34] Note that PAC has power plants but no customer loads in MT, CO and AZ.

[35] "Acknowledge" refers to a finding by a utility regulatory commission that does not guarantee recovery of costs of an action in a utility's retail rates, but finds the action to be reasonable at the time. This action is taken as a way of "approving" of proposed actions in a utility intergrated resource plan.

- Task 3, allocating compliance costs among states and utility customers through a series of manageably-scaled agreements ("manageable" in comparison to negotiating a single regional agreement).

If the utilities and states fail in any case to arrive at an agreement for any one plant, EPA has the authority and obligation to devise a Federal Implementation Plan to address this failure in the state where the plant is located.

Two or more such agreements could subsequently be rolled up into a larger PNW/IW regional operating agreement if the parties were to identify benefits from such a consolidation. Alternately a regional or westwide voluntary reduction "credits" trading mechanism might be deployed to widen the market for least-cost emissions reductions among plants and states; or states might elect to affiliate with California's AB 32 trading system or the Northeast states RGGI trading mechanism.

Attachment A: Clean Air Act Section 111(d)

(d) Standards of performance for existing sources; remaining useful life of source

(1) The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which

(A) establishes standards of performance for any existing source for any air pollutant

(i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) of this title or emitted from a source category which is regulated under section 7412 of this title but

(ii) to whch a standard of performance under this section would apply if such an existing source were a new source, and

(B) provides for the implementation and enforcement of such standards of performance. Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.

(2) The Administrator shall have the same authority—

(A) to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as he would have under section 7410 (c) of this title in the case of failure to submit an implementation plan, and

(B) to enforce the provisions of such plan in cases where the State fails to enforce them as he would have under sections 7413 and 7414 of this title with respect to an implementation plan.

In promulgating a standard of performance under a plan prescribed under this paragraph, the Administrator shall take into consideration, among other factors, remaining useful lives of the sources in the category of sources to which such standard applies.

Attachment B: PNW Regional Coal Plants

Northwest Utility Coal plant statistics									
Plant Name	Plant State	Owner	Nameplate Capacity MW	Average Capacity Factor (%)	Average Age (Years)	Average Heat Rate (Btu/kWh)	Particulate Control	SO2 Control	NOx Control
Carbon (UT) 1	Utah	PAC (100%)	75	79	56	11,439	Y	N	N
Carbon (UT) 2	Utah	PAC (100%)	114	79	53	11,516	Y	N	N
Dave Johnston 1	Wyoming	PAC (100%)	114	77	51	11,773	Y	N	N
Dave Johnston 3	Wyoming	PAC (100%)	114	77	50	11,467	Y	Y	Y
Naughton 1	Wyoming	PAC (100%)	163	83	47	12,257	Y	N (Planned)	N
Dave Johnston 2	Wyoming	PAC (100%)	230	77	46	11,320	Y	N	N
Naughton 2	Wyoming	PAC (100%)	218	83	42	12,204	Y	N (Planned)	N
Naughton 3	Wyoming	PAC (100%)	326	83	39	11,728	Y	Y	N
Dave Johnston 4	Wyoming	PAC (100%)	360	77	38	12,488	Y	Y	Y
Centralia Complex 2	Washington	TransAlta (100%)	730	70	38	12,173	Y	Y	Y
Centralia Complex 1	Washington	TransAlta (100%)	730	70	37	12,284	Y	Y	Y
Jim Bridger 1	Wyoming	PAC (66.55%)	578	74	36	10,447	Y	Y	N
Huntington (UT) 1	Utah	PAC (100%)	498	76	36	10,228	Y	Y	N
Jim Bridger 2	Wyoming	PAC (66.55%)	578	74	35	10,983	Y	Y	N
Colstrip 1	Montana	PSE (50%)	358	76	35	11,656	Y	Y	Y
Jim Bridger 3	Wyoming	PAC (66.55%)	578	74	34	12,137	Y	Y	N
Colstrip 2	Montana	PSE (50%)	358	76	34	11,998	Y	Y	N
Huntington (UT) 2	Utah	PAC (100%)	498	76	33	11,760	Y	Y	N
Wyodak	Wyoming	PAC (80%)	362	85	32	13,677	Y	Y	N
Hunter 1	Utah	PAC (85.8%)	488	74	32	10,757	Y	Y	N
Jim Bridger 4	Wyoming	PAC (66.55%)	584	74	31	12,101	Y	Y	N
Hunter 2	Utah	PAC (85.8%)	488	74	30	10,856	Y	Y	N
Boardman (OR)	Oregon	PGE (100%)	601	74	30	10,217	Y	N (Planned for 2014)	N (Planned for 2011)
Hunter 3	Utah	PAC (85.8%)	496	74	27	10,550	Y	Y	N
Cholla 4	Arizona	PAC (100%)	414	72	29	10,616	Y	Y	N
Craig (CO) 1	Colorado	PAC (19.29%)	446	83	31	11,026	Y	Y	Y
Craig (CO) 2	Colorado	PAC (19.29%)	446	83	30	10,688	Y	Y	Y
Colstrip 3	Montana	PSE (25%) PAC (10%)	778	76	27	12,878	Y	Y	N
Colstrip 4	Montana	PSE (25%) PAC (10%)	778	76	24	12,878	Y	Y	N

From "The War on Coal" BPA memo January 25, 2011; note that average age is calculated to 2011, and that emissions control data are out of date. Notes: (a) the 521 MW North Valmy facility in Nevada, not in this table, is 50% owned by Idaho Power which imports the power to its Idaho loads; (b) Idaho Power also owns one-third of the Jim Bridger units and 10% of Boardman; (c) PGE now owns 80% of Boardman, not the 100% shown in the table.

Attachment C: Ten Criteria for EPA 111(d) Existing Plant Carbon Rule

- Should collectively reduce emissions by more than 25-30 percent below current levels (2012) by 2020 (this is equivalent to 35-40% below 2005 levels)* and make further reductions thereafter.
- Require that emission reductions in state plans must be measurable, verifiable and enforceable.
- Should require that state plans include enforceable requirements for each individual covered source that collectively achieve the state target.
- Should cover all fossil fuel sources that generate electricity for the grid and are currently required to report their emissions.
- Should recognize for compliance all measures that quantifiably reduce emissions from the covered sources, including energy efficiency and renewable energy.
- The stringency of the performance standards set in EPA's guideline must reflect the full set of measures that can be used to comply.
- Should provide for approval of alternative state plans if they result in total carbon dioxide emissions from the power sector that are no higher than allowed by the performance standard in the guideline.
- States may adopt plans that are more stringent than the EPA guideline.
- So that states would have adequate notice of what the federal plan would be, EPA should propose a standby Federal Plan by June 2015 and promulgate it by June 2016 for states that choose not to submit an acceptable State Plan by that deadline.
- Should be reviewed and updated at least every eight years along with the new source standard.

- 35-40% below 2005 levels = 25-30% below 2012 emission levels = 500-600 million metric tons below 2012 levels = 850-950 million metric tons below 2005 levels.

PSC-317

Regarding: Comparison Of Northwest IOU Carbon Values
Witness: Hines, pp. 17-18, parts a, d, e / Fine, parts b & c

a. Please provide the data underlying Chart 3.

b. Please fully explain, in detail, and demonstrate through workpapers, how NWE calculated the average CO_2 cost per MWh for Avista, Idaho Power, Portland General Electric, Puget Sound Energy, and PacifiCorp.

c. Provide citations, including at what page of utilities' IRP the information can be found, for these other utilities' carbon price estimates

d. The vertical axis in Chart 3 is labeled in terms of dollars per MWh. However, the value shown for NWE in 2021 is $21.11, which corresponds to the cost per metric ton in the 2013 plan (see Volume 1, Chapter 5, Table 5-2). Please clarify whether the values in Chart 3 should be labeled in terms of dollars per ton.

e. How, if at all, is the calculation of utility averages for the purpose of presenting a multi-utility average in this chart different from the calculation of utility averages as presented in the line graph comparing NWE's carbon forecast to other utilities in the 2013 Resource Procurement Plan.

RESPONSE:

a. Please see the response to Data Request PSC-073a.

b. Please see the response to Data Request PSC-073a. A simple average was calculated for the years 2021, 2023, 2025, and 2030. The non-zero carbon cost values as presented in each IRP were used to create the values presented in the table for each utility.

c. Please refer to the following IRPs: Avista 2013 IRP Appendices page 420-421; Idaho Power 2012 IRP page 69; Portland General Electric 2012 IRP page 26; Puget Sound Energy 2013 IRP page 4-8 through 4-9; and PacifiCorp 2013 IRP page 168.

d. NorthWestern inadvertently mislabeled the Y axis. The y-axis in Chart 3 and the legend should be labeled "$/tonne".

e. By utility there is no difference; the respective year's values in Chart 3 equals the average of each individual utility's average for that year.

NorthWestern Energy
Docket D2013.12.85
PPLM Hydro Assets Purchase

Public Service Commission (PSC)
Set 14 (305-354)

Data Requests served May 23, 2014

PSC-318

Regarding: Rigor of Comparative Carbon Analysis
Witness: Hines, parts a & b / Dorris, part c

a. Describe how the Pacific Northwest utilities' IRPs arrived at various scenarios for carbon price. Were they based on specific possible policy outcomes, or were they based on something else?

b. Do these utilities' IRPs comment on the likelihood of various scenarios coming to pass?

c. Is it reasonable for NWE to give the same weight in calculating a supposed "average" of a utility's carbon price forecast that gives equal weight to that utility's "high" or "very high" scenario as it does that utility's "base case." Please explain.

RESPONSE:

a. Please see the response to Data Request PSC-317c.

b. Please see the response to Data Request PSC-317c.

c. NorthWestern did not develop an "average" carbon price based on other utility carbon prices. The purpose of comparing the price of carbon used by NorthWestern to neighboring utilities illustrates the relatively conservative (low price) assumptions of carbon utilized by NorthWestern. It should also be noted the zero carbon price scenarios for utilities in Washington and Oregon have not been accepted by state regulators. The methodology to model carbon prices is explained in *2013 Electricity Supply Resource Procurement Plan* pp. 26-28.

NorthWestern Energy
Docket D2013.12.85
PPLM Hydro Assets Purchase

Public Service Commission (PSC)
Set 14 (305-354)

Data Requests served May 23, 2014

PSC-319

Regarding: Exposure to Market
Witness: Hines, parts a & e / Stimatz, parts b, c, d

You state "Absent the acquisition of the Hydros, NorthWestern will be purchasing approximately 50 percent of the portfolio's needs from the short to intermediate term market." (4:15-18)

a. Define the time period you mean to indicate by "short to intermediate term market."

b. How much actual exposure does NorthWestern have presently, as a percentage of total supply as well as in MWhs purchased annually, to the spot market that is represented on your Chart 5?

c. What was the average cost of the purchases referred to in sub-part (b) for the 2012-2013 and, if available, 2013-2014 tracker years?

d. In what percentage of hours would NWE have *excess* electricity were the Hydros acquired (after the disposal of Kerr Dam)?

e. NWE states it is concerned about rate stability, but in its last RFP for market contracts, it limited itself to relatively short-term contracts as opposed to trying to negotiate another seven-year or longer contract that would extend into a period when NWE represents there would be more certainty on issues like carbon price. Why did NWE adopt this approach, which seems to have exposed it to the very problem (greater and supposedly unacceptable exposure to the market) that this filing ostensibly seeks to avoid?

RESPONSE:

a. Five years or less.

b. The question is unclear as it refers to the exposure that NorthWestern has "presently" to the spot market, but requests the answer in terms of the total MWh purchased annually. The term "spot market" typically refers to the day-ahead and hourly markets. For the 12-month period July 2014 through June 2015, NorthWestern's market exposure is approximately 1.3 million MWh, or about 20%.

c. The question is unclear as to whether it is referring to all market purchases or only spot market purchases. In the 2012-2013 tracker year, spot purchases averaged approximately \$19/MWh. The 2013-2014 tracker year is not complete. For the period of July 2013 through March 2014, spot purchases averaged approximately \$37/MWh.

PSC-319 cont'd

d. The question is unclear as it does not define the period for which it requests a percentage calculation. In any case, NorthWestern has not performed this analysis.

e. This question mischaracterizes certain details. First, NorthWestern does not believe the time frame from the date of issuance of the May 2013 RFP to the end date of contracted power (December 2017), or the time from the beginning date of contract delivery (July 2014) to the end date (December 2017), constitutes a short-term contract. Second, as NorthWestern has previously discussed, its preference in managing contracts to serve the supply portfolio is through the "plodding investor" approach. To enter into a power purchase contract for the entire future requirements of the portfolio, based upon one solicitation, is a less preferred methodology compared to a staggered approach. This was NorthWestern's intent – to issue additional competitive solicitations that were staggered over time. However, the final point is recognizing the timing of this solicitation – May 2013. In early May 2013, NorthWestern was notified of a two-phase process to sell PPLM's thermal and hydro assets. Prudently, given we had no certainty that it would be successful in negotiating the acquisition of the Hydros, NorthWestern continued to employ the process of meeting future resource needs through solicitations and conducted the May RFP. However, in addition to the reasons discussed above, it did not seek to acquire such a large quantity of power in the May 2013 solicitation that it would place NorthWestern in a very long position over an extended period, if it was ultimately successful in acquiring the Hydros.

PSC-320
Regarding: Bill Comparison
Witness: Hines

At the May 20, 2014 listening session you stated that with the adjustments NorthWestern proposed in its rebuttal testimony, bills in October 2014, with the hydro purchase, would be lower than bills in October 2013. Please provide the bill calculations that support that statement.

RESPONSE:

For the November 2013 estimated bill and associated calculation please see the Prefiled Direct Testimony of Patrick DiFronzo (Exhibit PJD-3, column F, row 28).

For the October 2014 estimated bill and associated calculation please see the Prefiled Rebuttal Testimony of Patrick DiFronzo (Exhibit PJD-7, column I, row 28).

PSC-321
Regarding: Deregulation Two
Witness: Hines

Throughout your rebuttal testimony you warn of a 'Deregulation Two' scenario if the hydros are not purchased by NWE. Deregulation was a condition imposed by the Montana Legislature that has since been repealed. Please explain why 'Deregulation Two' is an appropriate description when NWE still has the capability to purchase another generating asset or PPA to meet its supply obligations, even if NWE does not purchase the hydro assets.

RESPONSE:

I discuss the implications of "Deregulation Two" and why I believe this term is applicable on pages 3 through 7 of my rebuttal testimony. Specifically, please see JDH-4:1– JDH-5:14. Please note that my discussion relates to the effects on portfolio composition being consistent with the effects of deregulation (reliance on market purchases) if this application was denied.

PSC-322

Regarding: Comparable Acquisition Analysis
Witness: Stimatz

On 7:4-9 of your rebuttal you state: "If, as Dr. Wilson asserts, NorthWestern's estimate of the effect of future carbon prices on electricity prices were inflated and the resulting DCF value overstated, Credit Suisse would have found comparable asset sale prices to be much lower than the price of this transaction. In fact, Credit Suisse found the price of this transaction to be in line with comparable asset sales prices."

a. Please provide a citation to testimony where Dr. Wilson asserts that NorthWestern's estimate of the effect of future carbon prices on electricity prices is inflated.

b. Do you have evidence of the electricity price forecasts relied upon by the parties that purchased Masud's comparable assets and whether the forecasts include a carbon component? If so, please provide.

RESPONSE:

a. My testimony on page 7 refers to NorthWestern's electric price curves, which include CO_2 pricing, and the resulting DCF. Dr. Wilson repeatedly criticizes NorthWestern's DCF valuation and its carbon price estimates. Specifically, on page 12, lines 9-10 of his testimony, Dr. Wilson refers to "247.4 million of hypothetical and speculative capitalized CO2 tax costs"; on page 13, lines 6-7 he again refers to a competitive buyer "being unwilling to assume the risk of funding the $247.4 million of hypothetical CO2 costs embedded in NWE's DCF analysis"; and on page 13, lines 13-15 he asserts, "I think it is very doubtful that a competitive merchant buyer would be willing to fund $247.4 million of hypothetical CO2 taxes that may not be recoverable."

b. NorthWestern does not have the price curves used by the parties that purchased the comparable assets.

NorthWestern Energy
Docket D2013.12.85
PPLM Hydro Assets Purchase

Public Service Commission (PSC)
Set 14 (305-354)

Data Requests served May 23, 2014

PSC-323
Regarding: Residential Bill Impact
Witness: Stimatz, pp. 2-3, DiFronzo, Exhibit_(PJD-7)

a. On p. 3 you state that Mr. Clark assumes that, absent the Hydro purchase, NorthWestern would have done nothing to address the portfolio's intermediate to long-term baseload needs and would have relied on the spot market. Please explain whether the market products NWE acquired through its May 2013 RFP are examples of the type of resources NWE would have acquired absent the Hydro purchase?

b. Please provide: 1) historical, monthly Mid-C "around-the-clock" electricity prices on NWE's system for the period July 2007 through May 2014, 2) the quarterly prices associated with the seven-year, July 2007 through June 2014, PPA with PPL, and 3) NWE's electricity price forecast (used for resource planning purposes) on or about July 2006.

c. Are the products NWE acquired through its May 2013 RFP included in the portfolio costs underlying the bill impacts NWE estimated in data response PSC-034?

d. Are the products NWE acquired through its May 2013 RFP included in the portfolio costs underlying the bill impacts NWE estimated in Mr. DiFronzo's Exhibit_(PJD-7)?

e. Please provide a copy of NWE's response to data request PSC-002a in Docket D2013.5.33 (that data request asked for copies of contracts signed as a result of the May 2013 RFP). Alternatively, if NWE has prepared a summary of the total annual volumes and costs of the products it acquired through its May 2013 RFP, please provide that summary.

RESPONSE:

a. The types of products acquired in the May 2013 RFP – fixed price Mid-C purchases and on-system, index price purchases – would likely have been components of the portfolio absent the Hydro purchase. However, as has been the case for the last decade, NorthWestern's portfolio has a substantial need for on-system, baseload supply. Thus, the central component of the portfolio would likely have been on-system, multi-year, fixed price purchases, similar to the on-system purchases NorthWestern has entered in the past.

b. See Attachment 1, the requested historical, monthly Mid-C "around-the-clock" electricity prices, and Attachment 2, the requested NorthWestern/PPL seven-year deal prices. Electric Supply Resource Plans are submitted in odd-numbered years, so NorthWestern did not prepare a price forecast for resource planning purposes from on or about July of 2006.

PSC-323 cont'd

c. Yes, to the extent that the products from the RFP flow during the period covered by each bill estimate.

d. Yes, to the extent that the products from the RFP flow during the period covered by Exhibit__(PJD-7).

e. See Attachment.

Historical Monthly Mid-C Around the Clock Prices
Source: Intercontinental Exchange

Month	Mid-C Price	Month	Mid-C Price
Jul-07	$ 53.40	Jan-11	$ 26.57
Aug-07	$ 52.46	Feb-11	$ 22.73
Sep-07	$ 50.67	Mar-11	$ 16.96
Oct-07	$ 58.37	Apr-11	$ 21.21
Nov-07	$ 60.71	May-11	$ 15.78
Dec-07	$ 62.24	Jun-11	$ 13.71
Jan-08	$ 70.57	Jul-11	$ 20.77
Feb-08	$ 68.25	Aug-11	$ 28.51
Mar-08	$ 71.71	Sep-11	$ 31.56
Apr-08	$ 87.46	Oct-11	$ 26.09
May-08	$ 52.06	Nov-11	$ 31.00
Jun-08	$ 22.04	Dec-11	$ 30.74
Jul-08	$ 60.60	Jan-12	$ 25.14
Aug-08	$ 66.94	Feb-12	$ 23.58
Sep-08	$ 55.18	Mar-12	$ 16.50
Oct-08	$ 49.57	Apr-12	$ 9.44
Nov-08	$ 47.35	May-12	$ 6.20
Dec-08	$ 55.77	Jun-12	$ 4.88
Jan-09	$ 38.11	Jul-12	$ 12.76
Feb-09	$ 37.74	Aug-12	$ 25.28
Mar-09	$ 29.55	Sep-12	$ 24.56
Apr-09	$ 20.61	Oct-12	$ 30.62
May-09	$ 22.35	Nov-12	$ 27.92
Jun-09	$ 17.88	Dec-12	$ 24.42
Jul-09	$ 31.61	Jan-13	$ 27.51
Aug-09	$ 34.62	Feb-13	$ 28.50
Sep-09	$ 32.74	Mar-13	$ 31.62
Oct-09	$ 41.09	Apr-13	$ 26.11
Nov-09	$ 32.75	May-13	$ 24.86
Dec-09	$ 51.45	Jun-13	$ 28.23
Jan-10	$ 44.25	Jul-13	$ 34.63
Feb-10	$ 42.81	Aug-13	$ 33.67
Mar-10	$ 37.65	Sep-13	$ 34.37
Apr-10	$ 35.70	Oct-13	$ 34.42
May-10	$ 28.09	Nov-13	$ 34.39
Jun-10	$ 11.16	Dec-13	$ 50.89
Jul-10	$ 30.64	Jan-14	$ 40.18
Aug-10	$ 34.72	Feb-14	$ 68.72
Sep-10	$ 32.99	Mar-14	$ 26.03
Oct-10	$ 30.38	Apr-14	$ 25.23
Nov-10	$ 32.85	May-14	$ 21.39
Dec-10	$ 32.86		

NorthWestern - PPL Seven Year Deal Prices

Month	PPL 7-Year Deal Prices	Month	PPL 7-Year Deal Prices
Jul-07	$ 44.95	Jan-11	$ 50.55
Aug-07	$ 44.95	Feb-11	$ 50.55
Sep-07	$ 44.95	Mar-11	$ 50.55
Oct-07	$ 45.35	Apr-11	$ 50.95
Nov-07	$ 45.35	May-11	$ 50.95
Dec-07	$ 45.35	Jun-11	$ 50.95
Jan-08	$ 45.75	Jul-11	$ 51.35
Feb-08	$ 45.75	Aug-11	$ 51.35
Mar-08	$ 45.75	Sep-11	$ 51.35
Apr-08	$ 46.15	Oct-11	$ 51.75
May-08	$ 46.15	Nov-11	$ 51.75
Jun-08	$ 46.15	Dec-11	$ 51.75
Jul-08	$ 46.55	Jan-12	$ 52.15
Aug-08	$ 46.55	Feb-12	$ 52.15
Sep-08	$ 46.55	Mar-12	$ 52.15
Oct-08	$ 46.95	Apr-12	$ 52.55
Nov-08	$ 46.95	May-12	$ 52.55
Dec-08	$ 46.95	Jun-12	$ 52.55
Jan-09	$ 47.35	Jul-12	$ 52.60
Feb-09	$ 47.35	Aug-12	$ 52.60
Mar-09	$ 47.35	Sep-12	$ 52.60
Apr-09	$ 47.75	Oct-12	$ 52.65
May-09	$ 47.75	Nov-12	$ 52.65
Jun-09	$ 47.75	Dec-12	$ 52.65
Jul-09	$ 48.15	Jan-13	$ 52.70
Aug-09	$ 48.15	Feb-13	$ 52.70
Sep-09	$ 48.15	Mar-13	$ 52.70
Oct-09	$ 48.55	Apr-13	$ 52.75
Nov-09	$ 48.55	May-13	$ 52.75
Dec-09	$ 48.55	Jun-13	$ 52.75
Jan-10	$ 48.95	Jul-13	$ 52.80
Feb-10	$ 48.95	Aug-13	$ 52.80
Mar-10	$ 48.95	Sep-13	$ 52.80
Apr-10	$ 49.35	Oct-13	$ 52.85
May-10	$ 49.35	Nov-13	$ 52.85
Jun-10	$ 49.35	Dec-13	$ 52.85
Jul-10	$ 49.75	Jan-14	$ 52.90
Aug-10	$ 49.75	Feb-14	$ 52.90
Sep-10	$ 49.75	Mar-14	$ 52.90
Oct-10	$ 50.15	Apr-14	$ 52.95
Nov-10	$ 50.15	May-14	$ 52.95
Dec-10	$ 50.15	Jun-14	$ 52.95

NorthWestern Energy
Docket D2013.5.33
Electric Tracker

Montana Public Service Commission (PSC)
Set 1 (001-003)

Data Requests received January 17, 2014

PSC-002

Regarding: Solicitations and Power Purchase Agreements
Witness: Markovich

a. Please provide a copy of the competitive solicitation described in KJM-15:8-11, and copies of all power purchase agreements signed as a result of the solicitation.

b. For each transaction listed in Exhibit_(FVB-2)13-14, p.3, rows 9, 17, 33, 41, and 42; please provide a copy of the power purchase agreement and, if applicable, the RFP or RFI from which it resulted.

c. Please explain the purpose of the transactions displayed in rows 37-38 of Exhibit_(FVB-2)13-14, p.3.

RESPONSE:

a. See Attachment.

b. See Attachments 1 through 5, which are copies of the power purchase agreements listed in rows 9, 17, 33, 41, and 42. See also Attachment 6, a compilation of the RFPs from which these transactions resulted.

c. It is an hour ending (HE) 6 for HE 22 energy exchange whereby NorthWestern receives 75 MW in HE 6 and delivers 75 MW in HE 22. This transaction helps deal with the issue of serving load in Mountain Time while scheduling load in Pacific Time.

NorthWestern Energy

REQUEST FOR PROPOSALS - FIRM ELECTRICITY SUPPLY

May 9, 2013

I. Introduction

By this Request for Proposal (""RFP"), NorthWestern Energy ("NWE") invites proposals to provide firm electricity products ("Firm Supply") to NWE for the purposes of providing reliable service to retail customers in NWE's Montana Balancing Authority.

NWE is seeking up to 100 MW of Firm Supply for the period of January 1, 2015 through December 31, 2017 at Mid-C or on the NWE system, as described in more detail below. In addition, NWE is seeking up to 300 MW supply for the period of July 1, 2014 through December 31, 2014 on the NWE system.

No legal obligation will arise between NWE and any respondent absent a definitive final agreement executed by each party.

II. General RFP Requirements

NWE requests proposals based on the following minimum criteria:

A. Delivery Points.

NWE requests offers for the delivery of Firm Supply to: (1) the Mid Columbia trading hub ("Mid-C"), or (2) NWE's transmission system as specified in the product descriptions in Section III.

NWE will not select an on system offer if an acceptable delivery point has not been determined prior to the Submission Deadline.

B. Price of Service.

For deliveries to the NWE system, NWE will only accept proposals: (1) based on a fixed price per megawatt hour (MWh); or (2) proposals based on the Intercontinental Exchange (ICE) day-ahead index for Mid-C Peak and Mid-C Off-Peak transactions.

For deliveries to Mid-C, NWE will only accept proposals based on a fixed price per MWh.

C. Contract.

NWE will utilize industry standard agreements such as the WSPP, EEI, ISDA, or other similar standard agreements with the successful respondent(s).

Respondents may submit, provided the terms of existing contractual arrangements allow, offers pursuant to an existing enabling agreement between respondent and NWE.

For respondents without existing enabling agreements, NWE will negotiate in good faith a contractual relationship that would govern the terms of the transaction(s) in the event that the respondent is successful under this RFP. NWE makes no warranty that an enabling agreement will be executed prior to the Submission Deadline and reserves the right to terminate negotiation with any and all potential suppliers at any time during the process.

If there is no acceptable enabling agreement between NWE and a respondent at the Submission Deadline, the offer will not be considered.

D. Credit.

Respondent must indicate how credit will be addressed in its offer. For clarification, NWE will not require margining relative to any transaction that ultimately arises from this process provided that the counterparty maintains an investment grade rating and that the counterparty does not require margining by NWE.

NWE will not grant open credit to a respondent that does not meet its internal creditworthiness standards. NWE will, in its sole discretion, consider a letter of credit or some other acceptable form of collateral in the event a respondent does not meet these standards.

Respondents that do not maintain an investment grade rating or that propose alternate credit arrangements should contact NWE as soon as possible, but no later than May 22, 2013, to discuss potential arrangements. Upon request, respondent shall provide information allowing NWE to evaluate respondent's creditworthiness.

E. Draft Confirmations.

Each respondent shall provide to NWE a draft confirmation for each product on which it intends to bid on or before May 22, 2013. The draft confirmation will include proposed delivery points, a description of the Firm Supply, and any and all terms and conditions, other than price and quantity, which the bidder expects to include in a final confirmation in the event that its bid is selected.

III. Supply Requirements:

A. Firm Supply.

Firm Supply must include firm energy with contingency (operating) reserves.

B. Products Requested.

NWE requests Firm Supply proposals for the following volumes and terms:

Product #1: Mid-C On-Peak Fixed Price Purchase

Term A:	1/1/2015 through 12/31/2015
Term B:	1/1/2016 through 12/31/2016
Term C:	1/1/2017 through 12/31/2017
Volume:	Fixed quantity of up to 100 MW in 25 MW increments
Type:	Firm Supply
Delivery:	Mid-C
Price:	Fixed price per MWh (each term priced separately)

Product #2: Mid-C Off-Peak Fixed Price Purchase

Term A:	1/1/2015 through 12/31/2015
Term B:	1/1/2016 through 12/31/2016
Term C:	1/1/2017 through 12/31/2017
Volume:	Fixed quantity of up to 100 MW in 25 MW increments
Type:	Firm Supply
Delivery:	Mid-C
Price:	Fixed price per MWh (each term priced separately)

Product #3: NWE System On-Peak Index Based Purchase

Term A:	1/1/2015 through 12/31/2015
Term B:	1/1/2016 through 12/31/2016
Term C:	1/1/2017 through 12/31/2017
Volume:	Fixed quantity of up to 100 MW
Type:	Firm Supply
Delivery:	NWE System. NWE strongly prefers offers at delivery points with firm transmission availability.
Price:	Based on the ICE day-ahead Mid-C Peak index plus or minus a fixed amount per MWh.

Product #4: NWE System Off-Peak Index Based Purchase

Term A:	1/1/2015 through 12/31/2015
Term B:	1/1/2016 through 12/31/2016
Term C:	1/1/2017 through 12/31/2017
Volume:	Fixed quantity of up to 100 MW

Type:	Firm Supply
Delivery:	NWE System. NWE strongly prefers offers at delivery points with firm transmission availability.
Price:	Based on the ICE day-ahead Mid C Off-Peak index plus or minus a fixed amount per MWh.

Product #5: NWE System On-Peak Fixed Price Purchase

Term A:	1/1/2015 through 12/31/2015
Term B:	1/1/2016 through 12/31/2016
Term C:	1/1/2017 through 12/31/2017
Volume:	Fixed quantity of up to 100 MW
Type:	Firm Supply
Delivery:	NWE System. NWE strongly prefers offers at delivery points with firm transmission availability.
Price:	Fixed price per MWh (each term priced separately).

Product #6: NWE System Off-Peak Fixed Price Purchase

Term A:	1/1/2015 through 12/31/2015
Term B:	1/1/2016 through 12/31/2016
Term C:	1/1/2017 through 12/31/2017
Volume:	Fixed quantity of up to 100 MW
Type:	Firm Supply
Delivery:	NWE System. NWE strongly prefers offers at delivery points with firm transmission availability.
Price:	Fixed price per MWh (each term priced separately).

Product #7: 2014 NWE System On-Peak Index Based Purchase

Term A:	7/1/2014 through 12/31/2014
Volume:	Fixed quantity of up to 300 MW
Type:	Firm Supply
Delivery:	NWE System. NWE strongly prefers offers at delivery points with firm transmission availability.
Price:	Based on the ICE day-ahead Mid-C Peak index plus or minus a fixed amount per MWh.

III. RFP Responses

A. Response Presentation.

Respondents shall submit proposals which conform to the requirements of this RFP, and must provide NWE with sufficient information to adequately evaluate the offers.

Respondents must hold open the offers until the Award Notification date and time. At that time, verbal, telephonically recorded confirmations will be made pending final written confirmations.

B. Responses.

Respondents shall submit offers to this RFP by e-mail prior to the deadline to Joe Stimatz, Manager of Asset Optimization at the email address provided below.

Offers may be made on any or all products. NWE will select the combination of offers that it determines provides the highest value to NWE customers.

C. Schedule and Deadline to Respond.

The proposed procurement and selection process will be carried out in accordance with the following schedule:

Activity	Time and Date
RFP Issued	May 9, 2013
Draft Confirmations Due to NWE	May 22, 2013
Submission Deadline	**2:00 pm MDT on May 30, 2013**
Award Notification	4:00 pm MDT on May 30, 2013

All offers are due by 2:00 pm MDT on May 30, 2013. All offers must remain valid until 4:00 pm MDT on May 30, 2013.

NWE will notify successful the successful respondents, if any, by 4:00 pm MDT on May 30, 2013.

NWE Reserves the right to modify all or part of the proposed schedule set forth in this Article IV at any time during the RFP process.

V. Selection Criteria

Respondents must satisfy the specific requirements listed in this RFP document. Proposals not meeting the minimum requirements of this RFP will not be considered. Responses will be evaluated based upon price, the reliability of the Firm Supply and respondent financial and operational ability to provide the services outlined in the proposal. NWE reserves the right to consider any other factors that may be relevant to its Firm Supply needs.

NWE reserves the right, in its sole discretion: (1) to select some or none of the proposals; (2) to modify, revise, amend, or otherwise change the requirements of this RFP; and (3) to withdraw, in whole or in part, without notice, this RFP. This is an RFP and no binding legal obligation will be entered into unless and until the successful bidder and NWE negotiate and execute a definitive agreement.

VI. Confidentiality

NWE is a regulated entity and may be required to release RFP information to the appropriate regulatory authorities and other intervening parties during the course of regulatory proceedings. By submitting an offer pursuant to this RFP, respondent waives any objection to NWE's release of information to regulatory agencies or as otherwise required by law. NWE will not seek protection on behalf of any Respondent for the information contained in any offer.

VII. Contacts

Questions regarding this RFP should be directed to:

Joe Stimatz, Manager of Asset Optimization
joe.stimatz@northwestern.com
Phone: 406-497-3337
Cell: 406-490-3178
Fax: 406-497-2629

Credit questions should be directed to:

Dennis Heinz, Credit Manager
Dennis.Heinz@northwestern.com
Phone: 605-353-7517
Cell: 605-354-2163
Fax: 605-353-7560

WSPP Agreement Service Schedule C – Confirmation

Confirmation Date: May 30, 2013

1. **Transaction Specific Agreement**
   The undersigned Parties agree to a physical energy transaction pursuant to the WSPP Agreement, Service Schedule C, and the Master Confirmation Agreement under the WSPP Agreement between the Parties as further provided below:

Seller: TransAlta Energy Marketing (U.S.) Inc. ("TEMUS"), sometimes referred to as Seller, Party or collectively with NWE, Parties.

Purchaser: **NorthWestern Corporation dba** NorthWestern Energy ("NWE"), sometimes referred to herein as Purchaser, Party or collectively with TEMUS, Parties.

Period of Delivery: January 1, 2015 through December 31, 2015

Schedule (Days and Hours): Peak Hours

Peak Hours are defined as HE 0700 through HE 2200 PPT, Monday through Saturday, excluding NERC observed holidays. Off-Peak hours are defined as HE 0100 through HE 0600 and HE 2300 and HE 2400, Monday through Saturday, all day Sunday and NERC observed holidays.

Scheduling:
At the Point of Delivery ("POD"), TEMUS shall schedule the Delivery Rate each hour in accordance with the WECC scheduling calendar and the WECC Business Practices. TEMUS agrees to tag the transactions for scheduling purposes.

Delivery Rate:

Period	Jan 2015 – Dec 2015
Delivery Rate (MW/h)	25

Seller will deliver Product to the POD in an amount equal to the Delivery Rate. Seller may replace deliveries at the Alternate POD identified below, or some other mutually agreeable delivery point.

POD:	Mid-Columbia
Alternate POD:	NWE Transmission System upon mutual consent of both parties
Product:	WSPP Schedule C with Contingency (Operating) Reserves, as amended from time to time by the WSPP Agreement governing body.
Contract Quantity:	122,800 MWh
Contract Price:	$39.50/MWh USD

Special Conditions:

1) Credit

Both parties agree not to margin relative to these transactions provided that the other party maintains investment grade ratings from both Moody's and S&P. In the case of TEMUS, the senior unsecured credit rating will be that of its parent company, TransAlta Corporation. In the event of a split rating, the lower of the two shall apply.

TransAlta Energy Marketing (U.S.) Inc.

Authorized Signature of Seller

Calvin Johnson
Vice President
Trading and Asset Optimization

Name of Seller

June 03/13.

Date

NorthWestern Corporation dba NorthWest Energy

Dawn M Petritz

Authorized Signature of Buyer

Dawn M. Petritz
Director Energy Risk Management
6/03/13

Name of Buyer

Date

WSPP Agreement Service Schedule C – Confirmation

Confirmation Date: May 30, 2013

1. **Transaction Specific Agreement**
   The undersigned Parties agree to a physical energy transaction pursuant to the WSPP Agreement, Service Schedule C, and the Master Confirmation Agreement under the WSPP Agreement between the Parties as further provided below:

Seller: TransAlta Energy Marketing (U.S.) Inc. ("TEMUS"), sometimes referred to as Seller, Party or collectively with NWE, Parties.

Purchaser: **NorthWestern Corporation dba** NorthWestern Energy ("NWE"), sometimes referred to herein as Purchaser, Party or collectively with TEMUS, Parties.

Period of Delivery: January 1, 2016 through December 31, 2016

Schedule (Days and Hours): Peak Hours

Peak Hours are defined as HE 0700 through HE 2200 PPT, Monday through Saturday, excluding NERC observed holidays. Off-Peak hours are defined as HE 0100 through HE 0600 and HE 2300 and HE 2400, Monday through Saturday, all day Sunday and NERC observed holidays.

Scheduling:
At the Point of Delivery ("POD"), TEMUS shall schedule the Delivery Rate each hour in accordance with the WECC scheduling calendar and the WECC Business Practices. TEMUS agrees to tag the transactions for scheduling purposes.

Delivery Rate:

Period	Jan 2016 – Dec 2016
Delivery Rate (MW/h)	25

Seller will deliver Product to the POD in an amount equal to the Delivery Rate. Seller may replace deliveries at the Alternate POD identified below, or some other mutually agreeable delivery point.

POD:	Mid-Columbia
Alternate POD:	NWE Transmission System upon mutual consent of both parties
Product:	WSPP Schedule C with Contingency (Operating) Reserves, as amended from time to time by the WSPP Agreement governing body.
Contract Quantity:	123,200 MWh
Contract Price:	$41.40/MWh USD

Special Conditions:

1) Credit

Both parties agree not to margin relative to these transactions provided that the other party maintains investment grade ratings from both Moody's and S&P. In the case of TEMUS, the senior unsecured credit rating will be that of its parent company, TransAlta Corporation. In the event of a split rating, the lower of the two shall apply.

TransAlta Energy Marketing (U.S.) Inc.

Authorized Signature of Seller

Calvin Johnson
Vice President
Trading and Asset Optimization

Name of Seller

Date June 3/13

NorthWestern Corporation dba NorthWest Energy

Dawn M Petritz

Authorized Signature of Buyer

Dawn M. Petritz
Director Energy Risk Management
6/04/13

Name of Buyer

Date

WSPP Agreement Service Schedule C – Confirmation

Confirmation Date: May 30, 2013

1. **Transaction Specific Agreement**
The undersigned Parties agree to a physical energy transaction pursuant to the WSPP Agreement, Service Schedule C, and the Master Confirmation Agreement under the WSPP Agreement between the Parties as further provided below:

Seller: TransAlta Energy Marketing (U.S.) Inc. ("TEMUS"), sometimes referred to as Seller, Party or collectively with NWE, Parties.

Purchaser: **NorthWestern Corporation dba** NorthWestern Energy ("NWE"), sometimes referred to herein as Purchaser, Party or collectively with TEMUS, Parties.

Period of Delivery: January 1, 2017 through December 31, 2017

Schedule (Days and Hours): Peak Hours

Peak Hours are defined as HE 0700 through HE 2200 PPT, Monday through Saturday, excluding NERC observed holidays. Off-Peak hours are defined as HE 0100 through HE 0600 and HE 2300 and HE 2400, Monday through Saturday, all day Sunday and NERC observed holidays.

Scheduling:
At the Point of Delivery ("POD"), TEMUS shall schedule the Delivery Rate each hour in accordance with the WECC scheduling calendar and the WECC Business Practices. TEMUS agrees to tag the transactions for scheduling purposes.

Delivery Rate:

Period	Jan 2017 – Dec 2017
Delivery Rate (MW/h)	25

Seller will deliver Product to the POD in an amount equal to the Delivery Rate. Seller may replace deliveries at the Alternate POD identified below, or some other mutually agreeable delivery point.

POD:	Mid-Columbia
Alternate POD:	NWE Transmission System upon mutual consent of both parties
Product:	WSPP Schedule C with Contingency (Operating) Reserves, as amended from time to time by the WSPP Agreement governing body.
Contract Quantity:	122,400 MWh
Contract Price:	$43.35/MWh USD

Special Conditions:

1) Credit

Both parties agree not to margin relative to these transactions provided that the other party maintains investment grade ratings from both Moody's and S&P. In the case of TEMUS, the senior unsecured credit rating will be that of its parent company, TransAlta Corporation. In the event of a split rating, the lower of the two shall apply.

TransAlta Energy Marketing (U.S.) Inc.	NorthWestern Corporation dba NorthWest Energy
Authorized Signature of Seller	Authorized Signature of Buyer
Calvin Johnson Vice President ...and Asset Optimization	Dawn M. Petritz Director Energy Risk Management 6/04/13
Name of Seller	Name of Buyer
June 3/13	
Date	Date

WSPP Agreement Service Schedule C – Confirmation

Confirmation Date: May 30, 2013

1. **Transaction Specific Agreement**
   The undersigned Parties agree to a physical energy transaction pursuant to the WSPP Agreement, Service Schedule C, and the Master Confirmation Agreement under the WSPP Agreement between the Parties as further provided below:

Seller: TransAlta Energy Marketing (U.S.) Inc. ("TEMUS"), sometimes referred to as Seller, Party or collectively with NWE, Parties.

Purchaser: **NorthWestern Corporation dba** NorthWestern Energy ("NWE"), sometimes referred to herein as Purchaser, Party or collectively with TEMUS, Parties.

Period of Delivery: January 1, 2015 through December 31, 2015

Schedule (Days and Hours): Off-Peak Hours

Peak Hours are defined as HE 0700 through HE 2200 PPT, Monday through Saturday, excluding NERC observed holidays. Off-Peak hours are defined as HE 0100 through HE 0600 and HE 2300 and HE 2400, Monday through Saturday, all day Sunday and NERC observed holidays.

Scheduling:
At the Point of Delivery ("POD"), TEMUS shall schedule the Delivery Rate each hour in accordance with the WECC scheduling calendar and the WECC Business Practices. TEMUS agrees to tag the transactions for scheduling purposes.

Delivery Rate:

Period	Jan 2015 – Dec 2015
Delivery Rate (MW/h)	25

Seller will deliver Product to the POD in an amount equal to the Delivery Rate. Seller may replace deliveries at the Alternate POD identified below, or some other mutually agreeable delivery point.

POD:	Mid-Columbia
Alternate POD:	NWE Transmission System upon mutual consent of both parties
Product:	WSPP Schedule C with Contingency (Operating) Reserves, as amended from time to time by the WSPP Agreement governing body.
Contract Quantity:	96,200 MWh
Contract Price:	$29.75/MWh USD

Special Conditions:

1) Credit

Both parties agree not to margin relative to these transactions provided that the other party maintains investment grade ratings from both Moody's and S&P. In the case of TEMUS, the senior unsecured credit rating will be that of its parent company, TransAlta Corporation. In the event of a split rating, the lower of the two shall apply.

TransAlta Energy Marketing (U.S.) Inc.

Authorized Signature of Seller
Calvin Johnson
Vice President
Trading and Asset Optimization

Name of Seller

Date June 03/13

NorthWestern Corporation dba
NorthWest Energy

Dawn M Petritz
Authorized Signature of Buyer
Dawn M. Petritz
Director Energy Risk Management
6/03/13

Name of Buyer

Date

WSPP Agreement Service Schedule C – Confirmation

Confirmation Date: May 30, 2013

1. **Transaction Specific Agreement**
   The undersigned Parties agree to a physical energy transaction pursuant to the WSPP Agreement, Service Schedule C, and the Master Confirmation Agreement under the WSPP Agreement between the Parties as further provided below:

Seller: TransAlta Energy Marketing (U.S.) Inc. ("TEMUS"), sometimes referred to as Seller, Party or collectively with NWE, Parties.

Purchaser: **NorthWestern Corporation dba** NorthWestern Energy ("NWE"), sometimes referred to herein as Purchaser, Party or collectively with TEMUS, Parties.

Period of Delivery: January 1, 2016 through December 31, 2016

Schedule (Days and Hours): Off-Peak Hours

Peak Hours are defined as HE 0700 through HE 2200 PPT, Monday through Saturday, excluding NERC observed holidays. Off-Peak hours are defined as HE 0100 through HE 0600 and HE 2300 and HE 2400, Monday through Saturday, all day Sunday and NERC observed holidays.

Scheduling:
At the Point of Delivery ("POD"), TEMUS shall schedule the Delivery Rate each hour in accordance with the WECC scheduling calendar and the WECC Business Practices. TEMUS agrees to tag the transactions for scheduling purposes.

Delivery Rate:

Period	Jan 2016 – Dec 2016
Delivery Rate (MW/h)	25

Seller will deliver Product to the POD in an amount equal to the Delivery Rate. Seller may replace deliveries at the Alternate POD identified below, or some other mutually agreeable delivery point.

POD:	Mid-Columbia
Alternate POD:	NWE Transmission System upon mutual consent of both parties
Product:	WSPP Schedule C with Contingency (Operating) Reserves, as amended from time to time by the WSPP Agreement governing body.
Contract Quantity:	96,400 MWh
Contract Price:	$31.50/MWh USD

Special Conditions:

1) Credit

Both parties agree not to margin relative to these transactions provided that the other party maintains investment grade ratings from both Moody's and S&P. In the case of TEMUS, the senior unsecured credit rating will be that of its parent company, TransAlta Corporation. In the event of a split rating, the lower of the two shall apply.

TransAlta Energy Marketing (U.S.) Inc.

Authorized Signature of Seller
Calvin Johnson
Vice President
Trading and Asset Optimization

Name of Seller

Date June 3rd/13.

NorthWestern Corporation dba
NorthWest Energy

Dawn M Petritz

Authorized Signature of Buyer
Dawn M. Petritz
Director Energy Risk Management
6/04/13

Name of Buyer

Date

WSPP Agreement Service Schedule C – Confirmation

Confirmation Date: May 30, 2013

1. **Transaction Specific Agreement**
   The undersigned Parties agree to a physical energy transaction pursuant to the WSPP Agreement, Service Schedule C, and the Master Confirmation Agreement under the WSPP Agreement between the Parties as further provided below:

Seller: TransAlta Energy Marketing (U.S.) Inc. ("TEMUS"), sometimes referred to as Seller, Party or collectively with NWE, Parties.

Purchaser: **NorthWestern Corporation dba** NorthWestern Energy ("NWE"), sometimes referred to herein as Purchaser, Party or collectively with TEMUS, Parties.

Period of Delivery: January 1, 2017 through December 31, 2017

Schedule (Days and Hours): Off-Peak Hours

Peak Hours are defined as HE 0700 through HE 2200 PPT, Monday through Saturday, excluding NERC observed holidays. Off-Peak hours are defined as HE 0100 through HE 0600 and HE 2300 and HE 2400, Monday through Saturday, all day Sunday and NERC observed holidays.

Scheduling:
At the Point of Delivery ("POD"), TEMUS shall schedule the Delivery Rate each hour in accordance with the WECC scheduling calendar and the WECC Business Practices. TEMUS agrees to tag the transactions for scheduling purposes.

Delivery Rate:

Period	Jan 2017 – Dec 2017
Delivery Rate (MW/h)	25

Seller will deliver Product to the POD in an amount equal to the Delivery Rate. Seller may replace deliveries at the Alternate POD identified below, or some other mutually agreeable delivery point.

POD:	Mid-Columbia
Alternate POD:	NWE Transmission System upon mutual consent of both parties
Product:	WSPP Schedule C with Contingency (Operating) Reserves, as amended from time to time by the WSPP Agreement governing body.
Contract Quantity:	96,600 MWh
Contract Price:	$33.25/MWh USD

Special Conditions:

1) Credit

Both parties agree not to margin relative to these transactions provided that the other party maintains investment grade ratings from both Moody's and S&P. In the case of TEMUS, the senior unsecured credit rating will be that of its parent company, TransAlta Corporation. In the event of a split rating, the lower of the two shall apply.

TransAlta Energy Marketing (U.S.) Inc.	NorthWestern Corporation dba NorthWest Energy
Authorized Signature of Seller	Dawn M Petritz Authorized Signature of Buyer
Calvin Johnson Vice President Trading and Asset Optimization Name of Seller	Dawn M. Petritz Director Energy Risk Management 6/04/13 Name of Buyer
June 3/13 Date	Date

IBERDROLA RENEWABLES

CONFIRMATION

Via Facsimile

NorthWestern Energy

IR Trade No: SELL 21573894
Date: June 03, 2013

Fax Number:

This Confirmation Agreement confirms the oral agreement between Iberdrola Renewables, LLC ("Seller") and NorthWestern Energy ("Purchaser") regarding the sale and purchase of Firm energy pursuant to the Western Systems Power Pool ("WSPP") Agreement, under the following terms and conditions:

Trade Date:	05/31/2013
Seller:	Iberdrola Renewables, LLC
Purchaser:	NorthWestern Energy
Term:	1/1/2015 through 12/31/2015
Schedule.	Mondays through Saturdays, excluding NERC holidays, HE 07:00 PPT through HE 22:00 PPT
Delivery Point:	Mid-Columbia
Contract Price.	USD 39.9000 per MWH
Delivery Rate:	75 MW per hour
Contract Quantity:	368,400 MWh
Type of Service:	WSPP Schedule C
Level of Service:	Firm
Broker:	None

Scheduling: Both parties shall notify each other of preschedules by 10:30 PPT on the Business Day preceding the scheduled delivery, or as mutually agreed by the parties, in accordance with WECC guidelines.

Other: For all WSPP Schedule C, Seller is responsible to provide or procure contingency reserves. In the event of a conflict between the Netting Agreement (if applicable), the WSPP Agreement, the oral agreement, or this Confirmation Agreement, any such conflict shall be resolved by reference to the terms contained in such agreements in descending order of importance as follows: the Netting Agreement, the WSPP Agreement, the taped oral agreement, and this Confirmation Agreement.

Please indicate your acceptance of the terms stated herein by returning an executed copy of this Confirmation by facsimile to Iberdrola Renewables, LLC at 503.796.6905 within five Business Days. Failure to respond within five Business Days will not affect the validity or enforceability of this Transaction, and shall be deemed to be an affirmation of the terms and conditions contained herein, absent manifest error. Please contact IR Confirmation Administration at 503.796.7061 if you have any questions.

**Both parties agree not to margin relative to this transaction provided that the other party maintains investment grade ratings from both Moody's and S&P.

NorthWestern Energy
Authorized Signature

Dawn M Petritz

Name: Dawn M. Petritz

Title: Director Energy Risk Management

Date: ~~6/07/13~~

Iberdrola Renewables, LLC
Authorized Signature

Pam Simonsen PS

Name. Pam Simonsen

Title: Confirmations Administration

Date: June 03, 2013

IBERDROLA RENEWABLES

CONFIRMATION

Via Facsimile

NorthWestern Energy

IR Trade No: SELL 21573966
Date: June 03, 2013

Fax Number:

This Confirmation Agreement confirms the oral agreement between Iberdrola Renewables, LLC ("Seller") and NorthWestern Energy ("Purchaser") regarding the sale and purchase of Firm energy pursuant to the Western Systems Power Pool ("WSPP") Agreement, under the following terms and conditions:

Trade Date:	05/31/2013
Seller:	Iberdrola Renewables, LLC
Purchaser:	NorthWestern Energy
Term:	1/1/2016 through 12/31/2016
Schedule:	Mondays through Saturdays, excluding NERC holidays, HE 07.00 PPT through HE 22:00 PPT
Delivery Point:	Mid-Columbia
Contract Price:	USD 41.8500 per MWH
Delivery Rate:	50 MW per hour
Contract Quantity:	246,400 MWh
Type of Service:	WSPP Schedule C
Level of Service:	Firm
Broker:	None

Scheduling: Both parties shall notify each other of preschedules by 10:30 PPT on the Business Day preceding the scheduled delivery, or as mutually agreed by the parties, in accordance with WECC guidelines.

Other: For all WSPP Schedule C, Seller is responsible to provide or procure contingency reserves. In the event of a conflict between the Netting Agreement (if applicable), the WSPP Agreement, the oral agreement, or this Confirmation Agreement, any such conflict shall be resolved by reference to the terms contained in such agreements in descending order of importance as follows: the Netting Agreement, the WSPP Agreement, the taped oral agreement, and this Confirmation Agreement.

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**Both parties agree not to margin relative to this transaction provided that the other party maintains investment grade ratings from both Moody's and S&P.

NorthWestern Energy
Authorized Signature

Dawn M Petritz

Name: ~~Dawn M. Petritz~~
Title: Director Energy Risk Management
Date: 6/07/13

Iberdrola Renewables, LLC
Authorized Signature

Pam Simonsen

Name: Pam Simonsen
Title: Confirmations Administration
Date: June 03, 2013

IBERDROLA RENEWABLES

CONFIRMATION

Via Facsimile

NorthWestern Energy

IR Trade No: SELL 21574026
Date: June 03, 2013

Fax Number.

This Confirmation Agreement confirms the oral agreement between Iberdrola Renewables, LLC ("Seller") and NorthWestern Energy ("Purchaser") regarding the sale and purchase of Firm energy pursuant to the Western Systems Power Pool ("WSPP") Agreement, under the following terms and conditions:

Trade Date:	05/31/2013
Seller:	Iberdrola Renewables, LLC
Purchaser:	NorthWestern Energy
Term:	1/1/2017 through 12/31/2017
Schedule:	Mondays through Saturdays, excluding NERC holidays, HE 07:00 PPT through HE 22:00 PPT
Delivery Point	Mid-Columbia
Contract Price:	USD 43.7000 per MWH
Delivery Rate:	25 MW per hour
Contract Quantity:	122,400 MWh
Type of Service:	WSPP Schedule C
Level of Service:	Firm
Broker:	None

Scheduling: Both parties shall notify each other of preschedules by 10:30 PPT on the Business Day preceding the scheduled delivery, or as mutually agreed by the parties, in accordance with WECC guidelines.

Other: For all WSPP Schedule C, Seller is responsible to provide or procure contingency reserves. In the event of a conflict between the Netting Agreement (if applicable), the WSPP Agreement, the oral agreement, or this Confirmation Agreement, any such conflict shall be resolved by reference to the terms contained in such agreements in descending order of importance as follows: the Netting Agreement, the WSPP Agreement, the taped oral agreement, and this Confirmation Agreement.

Please indicate your acceptance of the terms stated herein by returning an executed copy of this Confirmation by facsimile to Iberdrola Renewables, LLC at 503.796.6905 within five Business Days. Failure to respond within five Business Days will not affect the validity or enforceability of this Transaction, and shall be deemed to be an affirmation of the terms and conditions contained herein, absent manifest error. Please contact IR Confirmation Administration at 503.796.7061 if you have any questions.

**Both parties agree not to margin relative to this transaction provided that the other party maintains investment grade ratings from both Moody's and S&P.

NorthWestern Energy
Authorized Signature

Dawn M Petritz

Name: Dawn M. Petritz
Title: ~~Director Energy Risk Management~~ 6/07/13
Date:

Iberdrola Renewables, LLC
Authorized Signature

Pam Simonsen pf

Name: Pam Simonsen
Title: Confirmations Administration
Date: June 03, 2013

IBERDROLA RENEWABLES

CONFIRMATION

Via Facsimile

NorthWestern Energy

IR Trade No: SELL 21573905
Date: June 03, 2013

Fax Number:

This Confirmation Agreement confirms the oral agreement between Iberdrola Renewables, LLC ("Seller") and NorthWestern Energy ("Purchaser") regarding the sale and purchase of Firm energy pursuant to the Western Systems Power Pool ("WSPP") Agreement, under the following terms and conditions:

Trade Date:	05/31/2013
Seller:	Iberdrola Renewables, LLC
Purchaser:	NorthWestern Energy
Term:	1/1/2015 through 12/31/2015
Schedule:	Mondays through Saturdays HE 01:00 through HE 06.00 and HE 23 00 through HE 24 00, Sundays and NERC Holidays HE 01:00 through HE 24:00 — all in Pacific Prevailing Time.
Delivery Point.	Mid-Columbia
Contract Price:	USD 29.9500 per MWH
Delivery Rate:	50 MW per hour
Contract Quantity:	192,400 MWh
Type of Service:	WSPP Schedule C
Level of Service:	Firm
Broker	None

Scheduling: Both parties shall notify each other of preschedules by 10:30 PPT on the Business Day preceding the scheduled delivery, or as mutually agreed by the parties, in accordance with WECC guidelines.

Other: For all WSPP Schedule C, Seller is responsible to provide or procure contingency reserves. In the event of a conflict between the Netting Agreement (if applicable), the WSPP Agreement, the oral agreement, or this Confirmation Agreement, any such conflict shall be resolved by reference to the terms contained in such agreements in descending order of importance as follows: the Netting Agreement, the WSPP Agreement, the taped oral agreement, and this Confirmation Agreement

Please indicate your acceptance of the terms stated herein by returning an executed copy of this Confirmation by facsimile to Iberdrola Renewables, LLC at 503.796.6905 within five Business Days. Failure to respond within five Business Days will not affect the validity or enforceability of this Transaction, and shall be deemed to be an affirmation of the terms and conditions contained herein, absent manifest error. Please contact IR Confirmation Administration at 503 796 7061 if you have any questions.

**Both parties agree not to margin relative to this transaction provided that the other party maintains investment grade ratings from both Moody's and S&P.

NorthWestern Energy
Authorized Signature

Dawn M Petritz
Dawn M. Petritz
Director Energy Risk Management
6/07/13

Name: ______

Title: ______

Date: ______

Iberdrola Renewables, LLC
Authorized Signature

Pam Simonsen

Name: Pam Simonsen

Title: Confirmations Administration

Date June 03, 2013

IBERDROLA RENEWABLES

CONFIRMATION

Via Facsimile

NorthWestern Energy

IR Trade No: SELL 21573987
Date: June 03, 2013

Fax Number:

This Confirmation Agreement confirms the oral agreement between Iberdrola Renewables, LLC ("Seller") and NorthWestern Energy ("Purchaser") regarding the sale and purchase of Firm energy pursuant to the Western Systems Power Pool ("WSPP") Agreement, under the following terms and conditions:

Trade Date:	05/31/2013
Seller:	Iberdrola Renewables, LLC
Purchaser:	NorthWestern Energy
Term:	1/1/2016 through 12/31/2016
Schedule:	Mondays through Saturdays HE 01:00 through HE 06:00 and HE 23:00 through HE 24:00, Sundays and NERC Holidays HE 01:00 through HE 24:00 — all in Pacific Prevailing Time.
Delivery Point:	Mid-Columbia
Contract Price:	USD 31.9000 per MWH
Delivery Rate:	25 MW per hour
Contract Quantity:	96,400 MWh
Type of Service:	WSPP Schedule C
Level of Service:	Firm
Broker	None

Scheduling: Both parties shall notify each other of preschedules by 10:30 PPT on the Business Day preceding the scheduled delivery, or as mutually agreed by the parties, in accordance with WECC guidelines

Other: For all WSPP Schedule C, Seller is responsible to provide or procure contingency reserves. In the event of a conflict between the Netting Agreement (if applicable), the WSPP Agreement, the oral agreement, or this Confirmation Agreement, any such conflict shall be resolved by reference to the terms contained in such agreements in descending order of importance as follows: the Netting Agreement, the WSPP Agreement, the taped oral agreement, and this Confirmation Agreement.

Please indicate your acceptance of the terms stated herein by returning an executed copy of this Confirmation by facsimile to Iberdrola Renewables, LLC at 503.796.6905 within five Business Days. Failure to respond within five Business Days will not affect the validity or enforceability of this Transaction, and shall be deemed to be an affirmation of the terms and conditions contained herein, absent manifest error. Please contact IR Confirmation Administration at 503.796.7061 if you have any questions.

**Both parties agree not to margin relative to this transaction provided that the other party maintains investment grade ratings from both Moody's and S&P.

NorthWestern Energy	Iberdrola Renewables, LLC
Authorized Signature	Authorized Signature
Dawn M Petritz	Pam Simonsen PS
Name: ~~Dawn M. Petritz~~	Name: Pam Simonsen
Title: Director Energy Risk Management	Title: Confirmations Administration
Date: 6/07/13	Date: June 03, 2013

CONFIRMATION LETTER NO. 2 – FIRM (LD) to the MASTER POWER PURCHASE AND SALE AGREEMENT Dated as of July 9, 2012

Agree
KAM
6/3/13

This confirmation letter shall confirm, the Transaction agreed to on <u>May 30, 2013</u>, between NORTHWESTERN CORPORATION, doing business as NORTHWESTERN ENERGY ("<u>Party A</u>"), and PPL ENERGYPLUS, LLC ("<u>Party B</u>") regarding the sale/purchase of the Product under the terms and conditions as follows:

<u>Seller</u>:	PPL EnergyPlus, LLC
<u>Buyer</u>:	Northwestern Corporation, doing business as Northwestern Energy
<u>Product</u>:	Firm (LD)
<u>Contract Term</u>:	From execution and delivery of this Confirmation through the Delivery Period.
<u>Delivery Period</u>:	July 1, 2014 to December 31, 2014
<u>Delivery Hours</u>:	The Delivery Hours for the Delivery Period shall be "On-Peak" hours, defined as Hour Ending (HE) 0700 through HE 2200 Pacific Prevailing Time (PPT), Monday through Saturday, excluding Sundays and NERC Holidays.
<u>Contract Quantity</u>:	200 MWh/hr all Delivery Hours of the Delivery Period.
<u>Total Contract Quantity</u>:	492,800 MWh
<u>Contract Price</u>:	Index minus $1.65/MWh. In no event shall the Index be less than zero ($0/MWh) for any hour of the Delivery Term when determining the Contract Price. "Index" means, for any day other than a Sunday or a NERC Holiday, the weighted average of the Intercontinental Exchange ("ICE") daily Mid-Columbia On-Peak Firm Power Price Bulletin for On-Peak Hours. For purposes of this definition, On-Peak hours shall include HE 0700 through HE 2200 Pacific Prevailing Time ("PPT").
<u>Delivery Point(s)</u>:	Seller's (Party B's) choice into Northwestern Energy's transmission system (NWMT).
<u>Scheduling</u>:	In accordance with the WECC Preschedule Calendar. Party A is responsible for providing all schedules and tags to the NorthWestern Balancing Authority.

Special Condition #1:
Confidentiality: This Confirmation shall be subject to the provisions of Section 10.11 of the Master Agreement; provided, however, that notwithstanding the foregoing, each Party will be entitled, without the consent of the other Party, to disclose such confidential information as and to the extent required by any regulatory authority having jurisdiction over such Party.

Special Condition #2:
Contingency Reserves: Party A and Party B will adhere to the NERC and WECC rules regarding responsibility for providing Contingency Reserves. For the purposes of this confirmation, Contingency Reserves shall mean operating reserves, both spinning and non-spinning (also referred to as supplemental). Party B will not be obligated to provide any other ancillary services, including, without limitation, Regulating Reserve or Frequency Responsive Reserve.

* * * * *

This confirmation is being provided pursuant to and in accordance with the Master Power Purchase and Sale Agreement dated as of July 9, 2012 (the "Master Agreement") between Party A and Party B, and constitutes part of and is subject to the terms and provisions of such Master Agreement. Terms used but not defined herein shall have the meanings ascribed to them in the Master Agreement.

[Signature page follows]

NORTHWESTERN CORPORATION,
doing business as
NORTHWESTERN ENERGY

Dawn M Petritz

Dawn M. Petritz
~~Director Energy Risk Management~~
6/03/13

PPL ENERGYPLUS, LLC

Teresa Bishop

5-31-13

Teresa H. Bishop
Trading Controls Analyst
406-533-3530
FAX: 406-533-0208

3

CONFIRMATION BETWEEN
Powerex Corp. * and Northwestern Corp. (Energy Supply Division)
Deal No. DYB475

This document ("Confirmation") confirms the verbal agreement reached on June 3, 2013 between Powerex Corp.* ("Powerex") and Northwestern Corp. ("NWE") regarding the sale and purchase of energy in accordance with the EEI Master Power Purchase & Sale Agreement ("Master Agreement") dated August 1, 2005 in force and effect between the Parties under the following terms and conditions. Consistent with Section 2.2 of the Master Agreement, this Transaction, together with all other Confirmations and the Master Agreement, form a single integrated agreement and are not separate contracts.

Buyer:	NWE
Seller:	Powerex
Term:	July 1 2014 through December 31 2015
Delivery Hours:	All hours of the term (around-the-clock)
Product:	Firm Energy
Quantity:	50 MW
Delivery Point:	BPAT.NWMT is the primary Delivery Point. Any unconstrained point on the NorthWestern transmission system may be substituted by Powerex.
Price:	ICE Mid C Peak Index minus $2.00 for Peak hours ICE Mid C Off-Peak index minus $3.50 for Off-Peak hours Peak hours shall be defined as Hour Ending (HE) 0700 through HE 2200 (16 hours per day) Pacific Prevailing Time (PPT), Monday through Saturday, excluding NERC Holidays Off-Peak hours shall be defined as hours means Mondays through Saturdays HE 0100-0600 and HE 2300-2400 PPT, and all day Sundays and including holidays defined by the NERC or any successor organization.
Scheduling:	Powerex shall arrange for deliveries on a pre-schedule and/or real time basis in accordance with WECC guidelines.

This Confirmation is being provided pursuant to and in accordance with the Master Agreement in force and effect between the Parties and constitutes part of and is subject to the terms and provisions of such Master Agreement.

Please confirm that the terms stated in this Confirmation accurately reflects the agreement between NWE and Powerex by returning an executed copy of this Confirmation by fax to Powerex at (604) 891-5045.

ACKNOWLEDGED AND AGREED TO:

Powerex Corp. *		Northwestern Corp. dba Northwest Energy	
By:	[signature]	By:	Dawn M Petritz
Name:	Robert Campbell Managing Director	Name:	Dawn M. Petritz ~~Director Energy Risk Management~~ 6/04/13
Title:		Title:	
Date:	June 7, 2013	Date:	

KPM 6/4/13

* Powerex Corp., doing business in California as Powerex Energy Corp.

PSC-324

Regarding: Residential Bill Impact
Witness: Stimatz, p. 4

You state that the exact terms and prices of the potential three- to five-year PPAs NorthWestern likely would have acquired absent the Hydro opportunity cannot be known, but certainly would have been higher than the short-term prices reflected in Mr. Clark's comparisons. Please clarify whether the prices would have been higher because current spot prices are higher than June 2013 spot prices, because the three- to five-year PPAs would have been priced higher than spot purchases, or because of some other reason.

RESPONSE:

NorthWestern expects that the prices for three- to five- year PPAs would have been higher at least in part because forward prices for later years were (and still are) higher than those for near years. For example, the levelized price for a five-year deal would be higher than the price for the first year of that deal because the forward price for the first year is the lowest of any year in that period.

PSC-325

Regarding: Lack of Direct Expert Testimony on Stochastic Modeling
Witness: Stimatz

No expert witness testified in NWE's initial application in support of Ascend's work with the PowerSimm model (i.e., it was presented by a NWE witness who, in discovery, said that he was not an expert in PowerSimm). Please explain why you did not present direct testimony in this matter, and explain why the Commission should not in the context of this proceeding discount the work of your firm, and instead favor tools such as the DCF that were supported by experts in DCF.

RESPONSE:

Consistent with its prior practice before this Commission, NorthWestern attempted to manage the number of witnesses presenting direct testimony. I testified to the results of the PowerSimm modeling as I am familiar with the results as well as portfolio management and portfolio modeling in general. And in fact, Dr. Dorris has been involved from the start due to his firm's modeling work for the 2013 Electricity Supply Resource Procurement Plan, which was provided as an exhibit to the Application.

As the direction of the case became clearer through discovery requests, NorthWestern determined that Dr. Dorris should indeed be a witness in the case. He provided answers to a number of discovery requests, made several presentations to Commission staff and personnel from the Commission's modeling consultant, Evergreen Economics, and provided rebuttal testimony in the case. He will be available for cross-examination at the hearing.

In addition, it is important to recognize that the Ascend modeling and the DCF modeling served different purposes. The Ascend modeling evaluated NorthWestern's portfolio with several different generation resources added. The DCF modeling was used to estimate the value of the Hydro assets to potential third party bidders.

PSC-326
Regarding: PowerSimm Modeling
Witness: Dorris

On page 7 you identify the resource alternatives that were combined with NorthWestern's existing resources and modeled in PowerSimm to evaluate the portfolio costs and risks (three resource alternatives were initially modeled for the 2013 plan and three others were modeled later for a supplement to the 2013 plan). In the course of assessing the adequacy of NorthWestern's application, Evergreen Economics and Ascend Analytics participated in a series of discussions regarding the PowerSimm model. On February 26, 2014, Evergreen Economics submitted a memo to Commission staff summarizing these discussions. One point of discussion concerned PowerSimm's capability for optimal capacity expansion planning.

a. Please confirm that, although PowerSimm is capable of supporting optimal capacity expansion planning, that capability was not used for the portfolio analyses included in NorthWestern's 2013 plan. If you cannot confirm, please explain.

b. If PowerSimm's optimal capacity expansion planning capability was not used to analyze portfolios for NorthWestern's 2013 plan, please explain whether Ascend Analytics and NorthWestern discussed the pros and cons of applying that capability to the 2013 plan analysis and, if so, describe those discussions fully and in detail.

c. To the extent not already discussed in your response to part (b) of this data request, what are the pros and cons of applying PowerSimm's optimal capacity expansion capability to a resource planning analysis?

d. Please clarify and explain whether you believe that the nature of NorthWestern's short position over the planning horizon warrants ignoring current and projected regional load-resource conditions, whatever those conditions may be?

e. If you believe expected regional load-resource conditions should be considered in a resource planning analysis, please explain whether NorthWestern adequately considered regional load-resource conditions and how applying PowerSimm's optimal capacity expansion planning capability would have accounted for regional load-resource conditions.

RESPONSE:

a. Ascend and NorthWestern did not use the optimal capacity expansion module of PowerSimm in preparing the analysis for NorthWestern's 2013 Plan. Instead, the analysis focused on fully exploring three realistic and practical capacity expansion choices and

PSC-326 cont'd

eventually three other portfolio plans as requested by the Commission. See also the response to part b, below.

b. NorthWestern and Ascend did discuss the potential for using PowerSimm's optimal capacity expansion module as part of the analysis for the 2013 Plan, but for several reasons did not choose to use it:

- NorthWestern has a relatively small number of practical resource choices to consider in capacity expansion analysis. Thus, the marginal benefit of employing the optimal capacity expansion module (relative to the analysis performed) was deemed to be negligible and possibly introduce unnecessary complexities to the current resource selection issue at hand.
- Consideration of resource additions beyond the current available choice set introduces additional unknowns today for planning choices that will not be made for years to come. In resource planning, we call this concept "capping end effects" to refer to minimizing the extent of future unknown resource additions biasing the choice set of today with unknown future generation technologies. The idea to limit the impact of future resource additions on the current choice set has been an outgrowth of planning in competitive power markets. Although resource planning has traditionally added resources for a full 20 to 40 years of future energy supply, the economic properties of adding new resources in future years such as 2025 and 2030 and 2035 serve to artificially contaminate the current resource selection process by introducing highly uncertain and new capital investment irrelevant to the current resource selection process.
- Deploying the optimal capacity expansion module would have introduced unnecessary complexity and cost into the analysis process for little demonstrable gain.

c. PowerSimm's optimal capacity expansion module is a powerful tool for utilities with many different resource options looking to automatically create a 20-year plan of future resource additions. The automatic resource selection process determines the optimal mix of future resource choices from generator conversions and retirements, renewables with different production profiles, conservation programs, etc. Given the limited set of options readily available to NorthWestern, and the desire to focus on near-term resource additions, the additional complexity that comes with the module's deployment was not warranted.

Because Ascend's optimal capacity expansion module is most useful for automating the process over the full planning horizon, including analyzing optimal new resource builds into the multi-decade horizon, this would have distracted from the central economic decision facing NorthWestern that involved near-term resource options.

PSC-326 cont'd

The analysis of optimal decisions in this near-term horizon (e.g. the Hydros acquisition versus new gas assets) does not require the analysis of all resource options in the later decades of the planning horizon, and furthermore the input data for those potential assets is not well-constrained.

d. The analysis performed for the 2013 Plan did not ignore current and projected load-resource conditions. Rather, the inputs to the model fully capture the current market consensus of future load-resource conditions, through use of forward curves that reflect the market's view of likely prices given all that is known about future load and resource availability. In addition, instead of simply using the expected value of these forward/forecast prices, PowerSimm also simulates price trajectories that conform to historical observations of market volatility. Thus, the 2013 Plan captures many different realizations of future load-resource conditions, based on market consensus at the mean but reflecting a full range of future conditions based on observed volatility. Furthermore, the future price streams were shown to adhere to critical fundamental conditions of long-run equilibrium where a new generic generation asset earned "normal" returns. It should be recognized that we have limited information today about the form and nature of the regional supply stack in ten years. Recognizing the limits of models to forecast the exact future state of demand and supply, a more economically realistic approach recognizes that all models are effectively bound by adhering to long-run equilibrium conditions for new generators. Thus, injecting uncertainty through simulations that capture the vicissitudes of economic cycles, commodity price movements, and variable hydro conditions yields a more realistic and robust forecast of future generation value.

e. As explained in part d, above, PowerSimm already considers regional load-resource conditions in a robust manner that captures not only the consensus mean, but also the long-run equilibrium, and meaningful uncertainty. Recognizing the solid incorporation of fundamentals into the analysis, NorthWestern more than adequately considered market fundamentals to forecast future power prices in its analysis for the 2013 Plan. Applying PowerSimm's optimal capacity expansion module would use the same underlying simulation framework and would have come to near-identical conclusions as the analysis NorthWestern performed (i.e., the Hydros represent the best, least-cost, and least-risk resource option).

PSC-327

Regarding: Integrated Resource Planning
Witness: Dorris

Once Ascend had modeled the 3 original portfolios NWE had chosen for the 2013 plan, what was the marginal effort and/or tasks that were necessary for Ascend to model additional portfolios? Please explain in detail.

RESPONSE:

The tasks required to model additional portfolios include:

- Data gathering, including collecting input data for new resource options (e.g., the LMS 100 or new wind assets), and ensuring it is in the correct format for input to PowerSimm.
- Portfolio configuration, including specification of start dates for new assets.
- Study runs.
    a. Large amounts of new analysis may require increased database storage space.
- Results analysis and validation of dispatch outcomes, including examining hourly results in detail and evaluating results to ensure consistency with previous analysis.

PSC-328
Regarding: PowerSimm Modeling
Witness: Dorris

a. If a utility expects regional load-resource conditions to tighten (i.e., reduced reserve capacity, greater probability of loads exceeding available resources) due to, for example, scheduled shut-down of existing generating capacity and/or increasing demand, would you expect the utility's forecast of market prices to reflect the effects of tighter load-resource conditions?

b. Does PowerSimm have the capability to distinguish between periods of general regional load-resource sufficiency, when market price volatility might tend to be lower, and periods of general load-resource insufficiency, when volatility might tend to be higher? That is, can the user do anything to define those periods in the model?

c. When using its optimal capacity expansion planning capability, what criteria does PowerSimm use to decide the best time to add new capacity and how much capacity to add?

d. The Regulatory Assistance Project states that probabilistic resource planning techniques:

> …force explicit recognition of probabilities associated with future states of the world and allow an examination of how multiple, small uncertainties can combine to create big risks. The tools are important in their ability to capture the relationship between variables, their requirements to specify the probabilities of all outcomes and their ability to provide an apparently definitive answer.
>
> The same ability to give a definitive answer is also one of the tool's most serious drawbacks. In reality, the analysis is "data free" because it is made in the absence of actual information. The subjective assumptions made early on in the analysis are submerged, so that the final outcome's appearance of objectivity is false.

(*Integrated Resource Planning for State Utility Regulators*, June 1994, p. 42.) Please explain whether this characterization of probabilistic analysis applies to the PowerSimm modeling in NorthWestern's 2013 plan.

e. With regard to Figure 2, on p. 10 of your testimony, please explain whether the total NPVs for each portfolio relate to the annual mean total costs shown in the Supply Cost

PSC-328 cont'd

Report included in the 2013 plan supplement. For example, if one were to calculate the NPV of the annual costs for 2014 - 2043 shown in the "Total Cost $M, Mean" row for the Current + Hydro portfolio, should the result be approximately the sum of the Existing Fixed + Capital, Variable + Market, and New Fixed + Capital – Residual Value shown in Figure 2 *if the residual value is added back in*? If not, please explain.

RESPONSE:

a. Yes, a reduction in regional reserve margins can create conditions where scarcity rents are accrued to generators and become manifest through increased spark spreads. NorthWestern's 2013 Plan addressed demand and supply imbalances through simulating monthly forward curves and permitting implied heat rates to vacillate from dis-equilibrium events of shortages and excesses of supply.

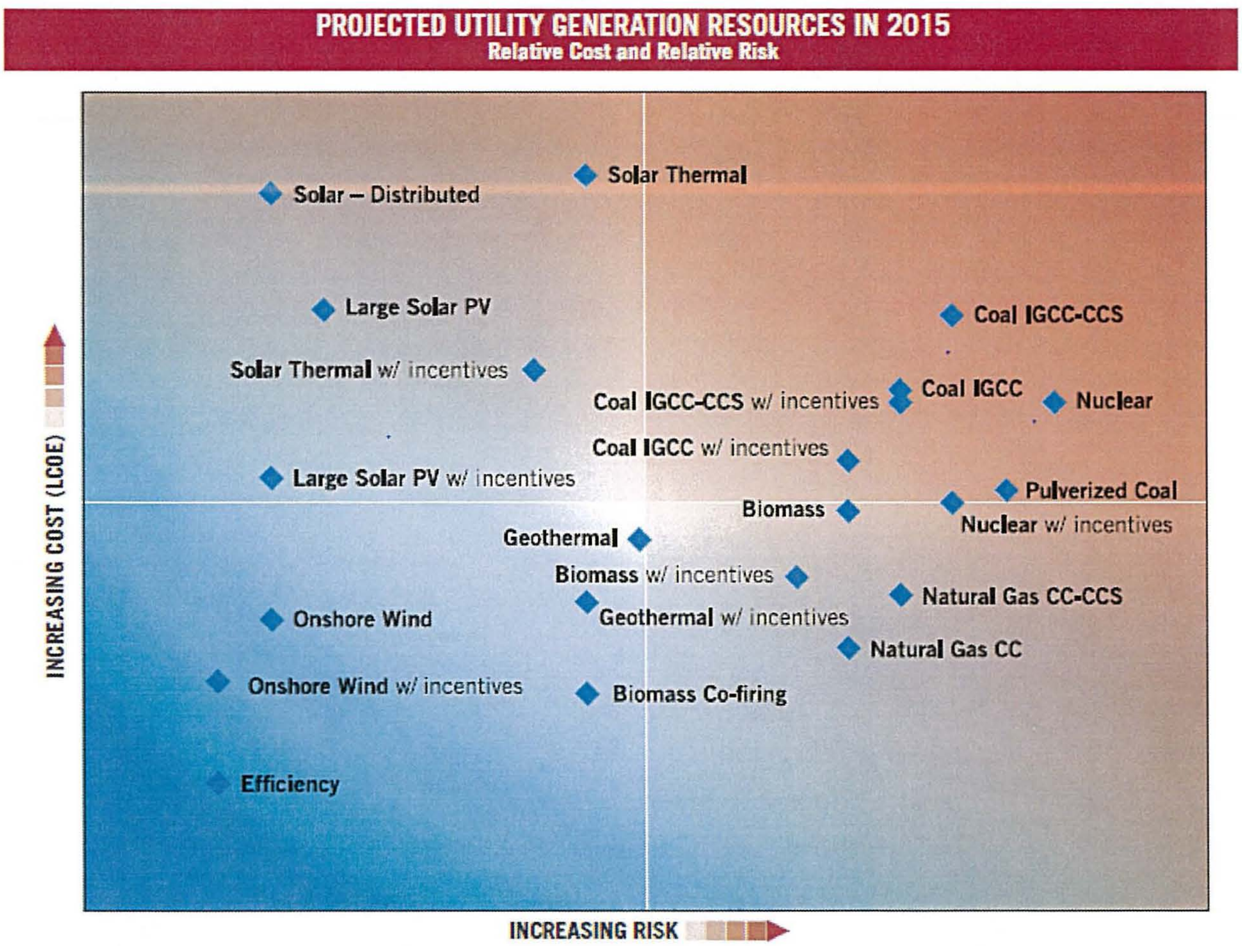
b. Yes, PowerSimm captures real business cycles where regional supply conditions ebb toward surplus levels and then shortages. Furthermore, users can create different input price volatility regimes by time period, as desired. PowerSimm can also use the historical record of forward price volatility for specific delivery dates to more objectively constrain the volatility of future simulations, without requiring a subjective forecast.

c. PowerSimm's optimal capacity expansion module minimizes the net present value of future revenue requirements subject to user defined planning constraints. Common planning constraints consist of reserve margins and energy balances of market purchases and sales.

d. The Regulatory Assistance Project's (RAP) characterization of the drawbacks of probabilistic models, published in 1994, is outdated and does not apply to NorthWestern's PowerSimm analysis. Rather than being "data free," as alleged by the RAP summary, the stochastic analysis method of PowerSimm in fact incorporates all relevant and available data that provides the best basis for modeling physical conditions (weather, load, and renewables), these conditions' impact on prices, as well as the market-consensus view of future market conditions. All inputs to the PowerSimm analysis framework are based on the most objective information available (e.g. historic data for weather, load, and price; engineering-economic characteristics of generators; and forward market curves for power and fuel) rather than subjective forecasts. No model can perfectly predict prices and other important drivers of portfolio costs into the future, but the stochastic approach used by PowerSimm is more objective than traditional, scenario-based deterministic analysis. Furthermore, our analysis has gone to substantial lengths to validate and benchmark the quality of the simulations. These validation results provide a critical analytic foundation of "meaningful uncertainty" into the simulation of future states.

PSC-328 cont'd

In April 2012, RAP published "Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know" by Ron Binz et. al. The report is subtitled, "How state regulatory policies can recognize and address the risk in electric utility resource selection." The publication discusses the need for regulators to consider risks inclusive of carbon, fuel, and power market prices. As an illustration of the need to include risks, Binz et. al. provides the relative risks and costs of different generic supply options:



e. The provided example correctly explains the relationship between my testimony's Figure 2 and the 2013 Plan Supplement Supply Cost Report. The NPV of 2015-2043 mean total costs for "Current + Hydro" (in 2013 dollars, keeping with the convention used in the 2013 Plan), calculated from the annual results in the Supply Cost Report, is $5,813.55M. The sum of Existing Fixed + Capital, Variable + Market, and New Fixed + Capital – Residual

PSC-328 cont'd

Value shown in Figure 2 for "Current + Hydro" is \$5,601.49M. Adding back the NPV of the Hydros' residual value (\$212.06M) to that total yields the identical total NPV of costs, \$5,813.55M.

NorthWestern Energy
Docket D2013.12.85
PPLM Hydro Assets Purchase

Public Service Commission (PSC)
Set 14 (305-354)

Data Requests served May 23, 2014

PSC-329

Regarding: Hydros vs. Market Purchases in Table 1
Witness: Dorris

a. In Table 1, the annual cost of market purchases for 2017 and 2018 appear to correspond to the historic period of market infirmity in the 2000 – 2001 period. Given changes in wholesale market regulations and market structures following that historic period of market infirmity, please explain whether an analysis of this sort should assess the likelihood of a similar event occurring in the near future or over the planning horizon?

b. If an analysis of the sort shown in Table 1 should assess the future likelihood of events similar to the market infirmity of 2000 – 2001, what is your assessment of that likelihood?

c. Is the "annual cost of market" price based on short-term market (i.e., spot or day- ahead market price) data? Why is this a reasonable yardstick when even those utilities that rely on the market often contract for longer terms which insulate them from momentary price spikes?

d. Provide the underlying data as well as any workbooks used to create Table 1.

RESPONSE:

a. The standards of prudency in resource planning demand that NorthWestern consider the historic precedent in evaluating the risk of substantial exposure to market prices. Even given the noted changes in market structure and regulation, the potential still exists for large price spikes. Table 1 is meant to be an illustrative example of what future conditions following the historic precedent might mean for NorthWestern's customers; however, the price volatility in the PowerSimm analysis performed for NorthWestern's 2013 Plan is based on historic transaction data for forward curves. The retrospective analysis incorporates an objective, data-driven representation of price volatility over an extended period. Removal of costs from 1999-2002 has the Hydro's costing $732mm versus the Market cost of $749mm. While the period of market infirmity provides substantial value, the Hydro's from 2003 to present were still less expensive than the market.

b. The analysis presented in Table 1, as noted above, is meant to be an illustrative example of the risks of relying on the market. Prudent analysis should consider the risks of price excursions consistent with the historic record, based on volatility in transaction prices for future commodity delivery.

PSC-329 cont'd

c. This question appears to presuppose that forward market purchase prices are less than the realized day-ahead spot market prices. If this supposition is in fact being made, it is groundless. The normative assumption is forward market prices are today's expectation of future realized spot prices. Alternatively, the question implies that by hedging, NorthWestern could somehow "outsmart" the market and avoid the impact of periods when market prices are high. Hedging can mitigate exposure to extreme events, but on average the expected payoff of a forward power contract remains zero.

d. See the folder labeled "PSC-329" on the CD attached to PSC-315 for the data underlying Table 1.

PSC-330

Regarding: Selection of Portfolios Modeled
Witness: Dorris

a. The second-least-expensive portfolio modeled by Ascend in PowerSimm surfaced only after the PSC asked NWE to study that scenario. Why should the Commission have confidence in a Resource Procurement Plan that did not even manage to surface the second-least-cost/least-risk option in its first iteration?

b. In your experience how many portfolios does a typical utility IRP model?

RESPONSE:

a. The cost and risk results for the five non-Hydros portfolios considered, presented in the 2013 Plan Supplement, are fairly similar, falling within a $111M range or within one percent of the cost of the Current. In contrast, the cost of the Hydros portfolio is $331M lower than the second least expensive option. A difference of this magnitude indicates a robust cost and risk advantage for the Hydros acquisition compared to other resource options, which all have roughly similar costs that are significantly higher. The alternative options that can be explored relative to the acquisition of the Hydros are within a relatively narrow cost neighborhood. The potential does exist to explore dozens of plans that do not further the resource selection process because they have costs within one percent of each other.

b. Resource planning should evaluate the economically relevant portfolios to support informed decision analysis. Examination of economically irrelevant resource options such as nuclear or new coal does not further enhance the resource selection process.

PSC-331

Regarding: Appropriate Number of Carbon Price Scenarios
Witness: Dorris

a. The record in this case seems to suggest that most, if not all, utilities have multiple carbon-price scenarios, and do not simply use a triangular distribution around a deterministic central price. Why is NWE's approach to this important variable advisable?

b. Please provide any examples of utilities who stochastically model carbon price by using a triangular distribution of a single, deterministic price point.

RESPONSE:

a. As explained in the 2013 Plan, simulating the price of carbon allows for a robust quantification of the impact of uncertain carbon pricing on total portfolio costs. Other utilities' practice of using deterministic scenarios shares the same disadvantages of using scenarios for other inputs (e.g. market and fuel prices, load, etc.). In a scenario-based analysis, stakeholders can choose their preferred scenario subjectively and ignore the risks introduced by uncertain input data. Simulating carbon price, like other input variables, allows the construction of a probabilistic envelope containing many more potential future outcomes, where analysts and stakeholders can be confident that any individual scenario they want to consider has been incorporated by the stochastic analysis.

b. None of the utility documents examined as part of the analysis for the 2013 Plan to characterize regional carbon price modeling practices used a triangular distribution. However, given the range of carbon prices observed in that survey, a triangular distribution was a prudent choice to capture a relatively low carbon cost range of potential future carbon prices.

PSC-332

Regarding: Figure 1, Cost Distributions by Portfolio
Witness: Dorris

a. Provide this figure's underlying data set.

b. Provide the figure with the other 3 portfolios represented.

c. Regarding the Y axis, are total simulations the same for each portfolio? If so, please provide the figure with frequencies on the Y axis, including total simulations for reference. If not, please provide the figure with probabilities in 5% intervals.

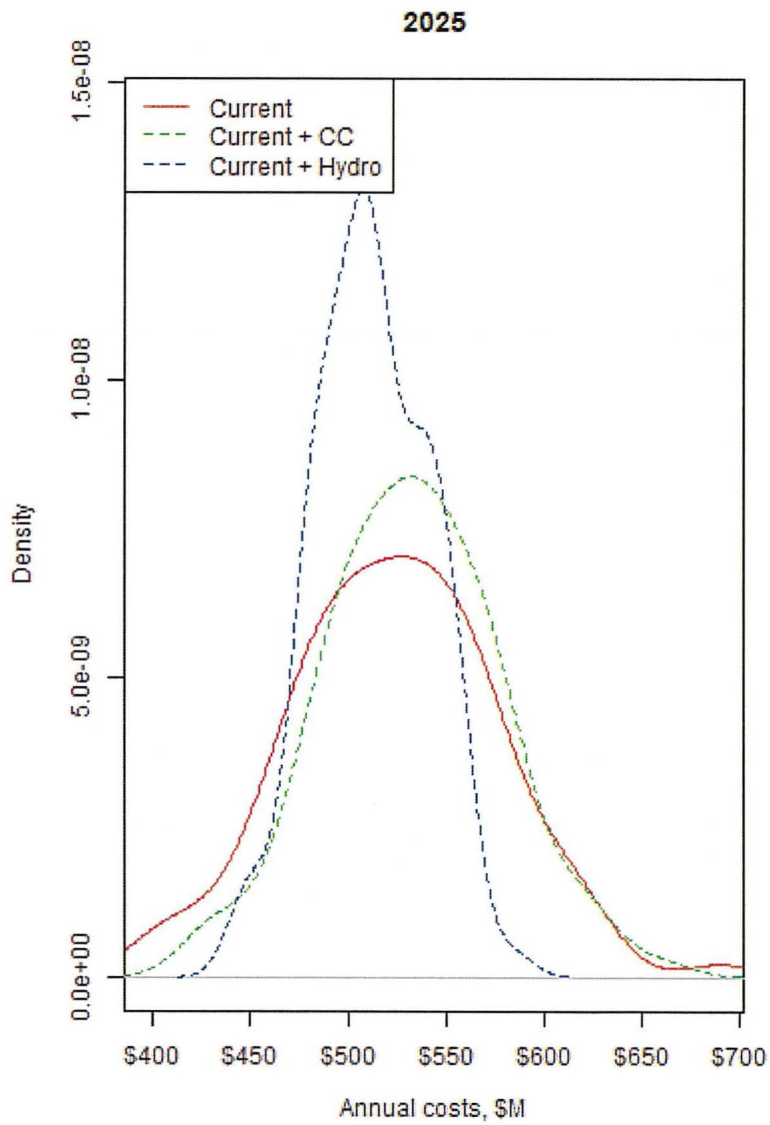
RESPONSE:

a. This figure is generated using the "density" function (with default parameters) built into the R statistical analysis package, which generates smooth curves showing distributions of cost outcomes that are more easily overlain and directly comparable than other formats (e.g. histograms) would be. The dataset provided in the folder labeled "PSC-332" on the CD attached to PSC-315 contains the realizations of annual cost for each of the three portfolios for each of the 100 simulation iterations performed as part of the analysis, which are used by the "density" function to create the figure.

b. The figure with the other three portfolios can be found on page 8 of the 2013 Plan Supplement.

c. Yes, the total number of simulations is the same (100) for each portfolio. The "density" function in R does not provide frequencies but rather a density estimate at each interpolated point on the cost distribution. The density estimate changes depending on the bandwidth used by the function, and so is not easily comparable to a frequency measure. However, the version of the figure with the density estimate plotted on the Y-axis is included below.

PSC-332 cont'd



PSC-333

Regarding: Concept of 'Secure' Supply
Witness: Dorris

a. You argue that a "short position of over 50%" exists, meaning that this is "the amount of supply that has not been secured" (11:11-15). By "secure," do you mean, exclusively, resources that the utility owns? Explain.

b. Why should a long-term PPA for a particular unit (such as Judith Gap) not be considered a "secure" source of supply?

c. Why should a long- or medium-term PPA for networked resources (such as the PPL- M plants) not be considered a "secure" source of supply?

d. Don't most gas local distribution companies, as well as many electric transmission- and-distribution companies, throughout the United States and the world rely mainly on "market" exposure—whether it be the spot market or medium- or long-term markets? Please explain why, in Montana, it should be unacceptable to be in a market position that appears to be routine practice elsewhere?

RESPONSE:

a. No. Secure supply refers to either owned or contracted capacity and energy.

b. The Judith Gap Purchase Power Agreement is a secure source of energy, but not of capacity.

c. PPAs are commonly contracted resources and can be considered a secure source of supply.

d. Most utilities actively take deliberate action to economically mitigate market exposure as a key component of prudent planning that provides solid benefits to rate payers. The Regulatory Assistance Project (RAP) April 2012 report, *Practicing Risk-Aware Electricity Regulation,* by Binz et. al. defines the challenge for effective regulation as "identifying and addressing risk" (pg. 2). Binz et. al. further suggests that "risk cannot be eliminated, but it can be managed and minimized". NorthWestern has an obligation to proactively manage energy supply risk to maintain reliable and cost-effective service to its customers. It is not acceptable to the consumers of Montana nor other states to bear the full burden of market vagaries. Thus, standard utility practice has been to manage these risks.

PSC-333 cont'd

In the case of electric transmission and distribution (T&D) companies, their supply is generally secured through full service provider agreements from asset backed utilities. It would be a far stretch to find T&D companies that serve retail customers without contracts to service load that mitigate market price exposure. Similarly, it is a misrepresentation to suggest that the near-term spot market has the same volatility and price dynamics as the longer-term market forward market. The forward market commonly serves as hedges against spot price movements. While utilities can substantially mitigate near-term market price exposure through acquisition of forward contracts, the single dependence on these market instruments creates substantial risk not realized by asset backed utilities.

PSC-334
Regarding: Post-Hoc Analysis
Witness: Dorris

Please provide any other examples of which you are aware of a utility which first agreed to purchase a resource, and only afterwards modeled it using stochastic modeling in an IRP to justify its acquisition.

RESPONSE:

Purchases of utility generating assets are commonly performed with a more simplistic analysis that is subsequently supported by more sophisticated modeling to address either regulatory requirements or commercial financing. I have participated in multiple asset acquisitions where the asset offer price analysis was similar to NorthWestern's spreadsheet model and subsequently supported by more complex analysis for commercial lending institutions.

The acquisition of the Hydros by NorthWestern naturally followed the process of developing an offer valuation with a more simplistic discounted cash flow (DCF) model that reasonably assessed the asset value. Subsequent to the offer to purchase, NorthWestern performed more comprehensive analysis that further substantiates the economic merit to acquire the Hydros. The process followed by NorthWestern parallels the activities pursued by merchant power generators in their acquisition of generating resources. The offers for acquisition of generating assets are commonly based on relatively simplistic modeling and then buttressed by more comprehensive analysis, often referred to as an "independent market assessment" to meet the lending criteria for commercial financing. In the case of NorthWestern, the more comprehensive analysis followed in the form of the 2013 Electricity Supply Resource Procurement Plan.

Based on my experience and review of electric utility resource plans, most utilities have been limited by their analytic tools to perform a comprehensive stochastic analysis. I have not been able find an electric utility resource plan that satisfied the rigorous standards of stochastic simulations to realize meaningful uncertainty as performed by NorthWestern. The effective asset valuation tools utilized by most utilities would be akin to the DCF model NorthWestern used in the development of the offer price. These common yet simplistic modeling approaches would fail to satisfy the standards of "Best Practices" attributed by Evergreen Economics to the NorthWestern 2013 Plan.

PSC-335
Regarding: Residual Value vs. Salvage Costs
Witness: Dorris

Does your Table 3: "Comparative Cost Analysis Without Residual Value" assume a $0 terminal value (i.e., no negative salvage value)?

RESPONSE:

Yes, as noted in Table 3, there is zero terminal value associated with the Hydros in the NPV of cost estimates in the last row of the table ($6,068M).

PSC-336

Regarding: California Carbon Prices
Witness: Dorris

a. Does California's cap-and-trade system impose price increases on wholesale electric markets outside of California, or does it decrease prices on such markets (because more resources are priced out of California market), or is it neutral on prices in such markets? Please explain.

b. What is the prevailing $/ton price for carbon in California?

RESPONSE:

a. California's cap and trade system ("AB 32") has varied effects on neighboring markets. At the most basic level, AB 32 increases demand and price for certified, low-emissions resources that can be imported into California. The opposite is true for high-emissions resources or resources lacking certification of their emissions factor. The overall impact on prices in neighboring markets depends on the balance of resources in each market and many other factors and is very difficult to quantitatively measure.

Importantly, AB 32 will soon be superseded by new federal regulations, and thus the impact of California's regulations on the price of low- versus high-emissions resources will be replicated, to some extent, in all regional markets. Namely, the value of low-emissions resources will grow relative to the value of high-emissions resources.

b. As of May 30, 2014 the price of 2014 vintage permits was $11.90/tonne[1] equivalent to $13.09 per ton. As noted in my testimony, this price must rise at an annual rate of at least 5% over inflation, per California law. Thus, the 2025 California floor price for carbon is $23.16/ton.

[1] www.californiacarbon.info

PSC-337

Regarding: Effect of Carbon Forward Market Prices
Witness: Dorris

What, if any, carbon price is already incorporated in the multi-year forward market price strip (before 2021) relied on by NorthWestern for its electricity market price forecast?
Please explain.

RESPONSE:

At the time the forward data were collected and prepared for the 2013 Plan, the forward curves for power had a tenor of four years through 2017 and gas had a tenor of seven years through 2020. Because the tenor of Power forward prices ended prior to the anticipated date of carbon regulations in 2021, carbon was not assumed to be incorporated into the forward price. However, carbon was explicitly included in the forecast price of power in 2021. Neither the forward nor forecast price of gas was adjusted for carbon legislation. Not adjusting the price of natural gas for carbon may be considered a conservative assumption because of the expected substitution of natural gas for coal. The substitution effect increases demand for natural gas and thus leads to higher prices.

NorthWestern Energy
Docket D2013.12.85
PPLM Hydro Assets Purchase

Public Service Commission (PSC)
Set 14 (305-354)

Data Requests served May 23, 2014

PSC-338
Regarding: Washington Commission Carbon Policy
Witness: Dorris

a. You use the term "disallowed" to describe what the Washington UTC did in respect to a recent Puget Sound Energy filing that proposed a $0/ton base case. In what sense did the WUTC "disallow" costs from rates? Or do you have another meaning for this term? Please explain.

b. Has the WUTC actually settled on a carbon price for the PSE IRP? If so, what is it? If not, describe the process and methodology which will be pursued to arrive at a reasonable carbon price in the PSE base case.

c. On 27:10-11 you state: "In doing so, the UTC effectively increased the value of low-carbon resources relative to that of the resource in question (Colstrip)." Please explain why a decision by the Washington Commission that may inflate the value of PPLM's hydro assets for Puget Sound Energy's Washington customers should make these assets more valuable to NorthWestern's Montana customers.

d. If the WUTC decision increased the value (and therefore the purchase price) of the hydro assets relative to the Colstrip assets, wouldn't this increase the value per dollar for NorthWestern of a Colstrip assets purchase relative to a hydro assets purchase?

e. If demand drops for Colstrip electricity due to the WUTC decision, won't this make Colstrip electricity more available and affordable for NorthWestern?

RESPONSE:

a. I use the term "disallow" in the context of the WUTC reaction to Puget Sound Energy's use of a zero CO_2 price base case in their recent IRP. From the document referenced in my testimony[2], the WUTC "instruct[ed] the Company to use a nonzero value [for CO_2 price] in the Base Scenario of its next IRP," and "The Commission considers a zero cost for CO_2 over the 20-year planning horizon unrealistic and unreasonable."

b. It is not clear from the record on file in Washington Docket UE-120767 whether a price has been selected, or what the exact process will be to determine that price. It is likely to be influenced by impending federal regulations.

[2] Attachment B, Utilities and Transportation Commission Comments on Puget Sound Energy's Colstrip Study, Docket UE-120767

PSC-338 cont'd

c. The anticipation of carbon regulation makes the Hydros a more valuable resource than fossil generation. Under carbon regulations, hydro generation becomes more favorable than fossil generation because of the added cost associated with carbon emissions from fossil resources. With recently announced federal regulations on carbon power resources, the value of the Hydros will be recognized nationally. If Washington State were to act unilaterally, then the Hydros and wind resources would carry a premium in the regional power market.

d. Under carbon regulations, brown power costs more and green power becomes worth more. The motions by Washington to regulate carbon were in anticipation of federal regulations and may have helped the state economically prepare itself for the recently announced federal regulations.

e. NorthWestern correctly concluded that Colstrip energy will be worth less than Hydros energy in a future with regional, federal, or even neighboring state-level emissions pricing.

PSC-339
Regarding: Value of Low-Emissions Resources
Witness: Dorris

In 26:10 – 28:4 you explain that a third-party competitive bidder would be able to obtain the value of unrealized CO_2 costs by selling the power from the hydros to markets and/or utilities in California, Washington, and Oregon. Please describe what costs, such as wheeling, would be incurred by a third-party competitive bidder who sold power from the hydros into those aforementioned markets that will not be incurred by NWE when it sells power from the hydros to local customers on its own distribution system.

RESPONSE:

The magnitude of wheeling and other costs associated with exporting Hydros energy out of state is difficult to calculate exactly, but largely irrelevant. NorthWestern should evaluate the exact same set of costs as any other competitive bidder, because the value of the Hydros is determined by the market value of their energy wherever it is delivered, by any potential owner. NorthWestern will dedicate the Hydros energy to its Montana retail customers, but it is correct to account for the opportunity costs of such an allocation by also valuing the Hydros energy against regional markets. This valuation should include carbon pricing as well as any applicable wheeling or other costs.

PSC-340

Regarding: Carbon Price when Marginal Unit is Non-Thermal
Witness: Dorris and Stimatz

Periodically in the Pacific Northwest, non-thermal units (hydro and wind) are sufficient to meet load, and since thermal resources such as coal and natural gas are not dispatched, a thermal resource is not the marginal unit. What adjustments, if any, have Ascend and NorthWestern made in both PowerSimm and the DCF models to ensure that these hours (when the market presumably would have no imputed CO2 cost because the marginal unit is not emitting CO2) are properly modeled?

RESPONSE:

Stimatz response: NorthWestern disagrees with the premise that there are times when no thermal units are dispatched. The DCF model used pricing that reflects the efficiency of the marginal unit in the market and the appropriate CO_2 adder for the marginal unit at the monthly on- and off- peak level. See the Stimatz Direct Testimony on pages 26-27 for a description of how the CO_2 price was applied to the market price.

Dorris response: In the stochastic modeling, NorthWestern used an industry-standard value for all hours that averages out times when coal, gas, and non-thermal generation are on the margin. Explicitly accounting for particular hours when the carbon price scalar may be lower or higher would require much more complicated, regional-scale modeling with highly uncertain inputs, but would not meaningfully impact results.

PSC-341
Regarding: Rainbow Redevelopment Project
Witness: Rhoads, parts a, b, & e / Stimatz, parts c & d

You contend that the Rainbow Redevelopment Project was a voluntary, economic project in which efficiencies were gained.

a. What efficiency savings resulted in the fixed O&M budget, on a $/kw-year and on a total annual basis, from the investment?

b. What capacity gains, on a $/MW basis, were achieved by expanding the generating capacity at Rainbow and because of the expanded generating capability at another dam (Cochrane)?

c. How many additional megawatt-hours do the capacity gains referenced in sub-part (b) achieve? What is the total dollar value of those additional megawatt-hours based on current market prices?

d. How long would it take for the investment in the Rainbow Redevelopment Upgrade to be recovered from the O&M savings identified in sub-part a and from the additional energy output identified in sub-part c?

e. Please provide comparable examples of where Hydro owners have made investments of this nature, in line with the value proposition revealed in sub-part d of this question.

RESPONSE:

a. Given that such analysis would have been conducted by PPLM in support of the project, NorthWestern does not have this information. Please also see the VanDaveer Rebuttal Testimony, page JCV-6, line 14 through page JCV-7, line 4.

b. The design capacity gain at Rainbow was 24 MW and the design capacity gain at Cochrane was 5 MW. The cost of the Rainbow rehabilitation was approximately $195 million (with the renewable energy tax credit deducted). NorthWestern believes this value has little relevance. NorthWestern does not know the ultimate cost of the capacity gain because there also would have been a cost to the other alternatives that may have been considered, such as rehabilitating the existing eight units or the "do nothing" option. Please also see the response to part a, above.

PSC-341 cont'd

c. The amount of generation gained will depend on the water year. Based on historical average capacity factors, the capacity gains would provide about 180,000 – 185,000 MWh in an average year. See the "Summary By Plant" tab in the file "Stimatz – Historical Generation Table p. JMS-9.xls" that was provided on the Witnesses' Electronic Supporting Data CD. Column D shows the historical average generation; Column H shows the historical average generation adjusted for the capacity gains. NorthWestern has not analyzed the total dollar value of the additional megawatt-hours of generation. Please also see the responses to parts a and b, above.

d. NorthWestern has not performed the requested analysis. Please also see the responses to parts a and b, above.

e. NorthWestern does not have such a list.

PSC-342
Regarding: Materiality/Unknown Cost of Environmental Liabilities
Witness: Sullivan, parts a, c, d / Rhoads, part b

a. You write on 21:18-20, "These potential issues [various environmental liabilities] were identified, thoroughly examined, and their future potential impacts to the Hydros are not material and/or cannot be defined at this time." Which of the liabilities listed in this question are considered immaterial, and which are undefinable at this time, and which fall into both categories?

b. In response to a question at a public listening session in Great Falls, you said that the owner of the dam behind which contaminated sediment had built up would attempt to assign the cost of remediating that problem to the party responsible for it. Is this a correct understanding of NWE's position?

c. Assuming that liability cannot be assigned to that company because it is bankrupt or otherwise unable to remediate the damage it caused, would it then be NWE's responsibility under law to remediate this pollution?

d. Has NWE evaluated the cost of remediating this pollution?

RESPONSE:

a. In his rebuttal testimony, at page 21, lines 17-18, immediately preceding the material quoted in this data request, Mr. Rhoads stated, "The Sullivan Rebuttal Testimony specifically addresses the limited potential risk of each of these areas." To understand my response to this data request, it is important to understand NorthWestern's due diligence process and determination of materiality. During the due diligence process, the team searched for things that could be fatal to the acquisition of the Hydros. Initially, the team identified environmental issues that could potentially cost more than $100,000/year for further examination. After identification, each potential issue was examined closely for materiality. At this time and for purposes of this response, I assume "material" is defined as costs in excess of $500,000 per year. This is a conservative definition of "material" in view of the value of both the hydro transaction and the assets of NorthWestern.

Neither the estimated costs associated with ACM Superfund site near Black Eagle nor the estimated costs associated with the contaminated sediments at Thompson Falls reservoir are material. NorthWestern has accounted for the estimated costs associated with these potential environmental liabilities as discussed in my Additional Issues Testimony (pages MGS-11-MGS-13).

PSC-342 cont'd

Regarding Arctic grayling, the team estimated that if listing occurs the higher end of the range of potential total costs would be $5,000,000 to $7,000,000 and such costs would be incurred over nine to ten years. This estimate, however, was conservative – a "highest cost" scenario – because it assumed there would be five years of extensive study and installation of a fish ladder. As explained in my Rebuttal Testimony (pages MGS-7-MGS-9), it is too soon to provide any reasonable estimate of the costs of studies and mitigation, but it is unlikely that those total costs, even if listing occurs, will be material.

b. Yes, as set forth in Mary Gail Sullivan's Additional Issues Testimony (MGS-3), NorthWestern's position is that the party responsible for the contamination should be responsible for the cost to address the contamination.

c. This question requires a legal analysis, which NorthWestern has not done. However, for information purposes, it is important to remember that the boundary of the ACM Superfund Site has not even been determined and so it is not clear whether any part of the Black Eagle facility will be included as part of this Superfund Site. Further, even if the Black Eagle facility should eventually become part of the ACM Superfund Site, NorthWestern does not believe that the dam owner should be held responsible for response costs for at least three reasons. First, there is no evidence that ARCO-BP will lack the financial wherewithal to pay response costs. Second, there is no dispute about the source of the contamination and there is no allegation that Black Eagle dam operations contributed to the contamination. Third, even if you assume ARCO-BP will not be capable of paying response costs, EPA could itself direct the remediation and tap the Superfund to cover the investigation and cleanup costs.

d. No. To my knowledge, no party or government agency has attempted to estimate the total response costs for the ACM Site. This is understandable because the boundaries of the Superfund Site have not been defined and the Remedial Investigation/Feasibility Study has not been completed.

PSC-343

Regarding: Amended Conditions
Witness: Meyer, part a / Bird, part b

a. At 15:2-12 you describe amended amortization and investment return conditions. Please provide an electronic copy of the revenue requirements model (Meyer) that is updated for these conditions.

b. If the Commission approves the transaction, is NorthWestern planning to return for a general rate case in order to meet the expected increase in revenue requirement shown in the Meyer model following the transfer of Kerr in 2016?

RESPONSE:

a. See the folder labeled "PSC-343" on the CD attached to PSC-315.

b. As noted in my direct testimony we expect to file a compliance filing to handle any adjustment in the Commission's final order in this matter (e.g., purchase price adjustments and update debt costs) and a subsequent compliance filing to remove the remainder of Kerr from the revenue requirement upon conveyance. See pages BBB-25 and BBB-34 of my direct testimony as a reference.

Any future adjustments to electric rates, including owned generation assets, would be considered part of a fully integrated electric utility general rate request.

NorthWestern Energy
Docket D2013.12.85
PPLM Hydro Assets Purchase

Public Service Commission (PSC)
Set 14 (305-354)

Data Requests served May 23, 2014

PSC-344
Regarding: First Energy-LS Power Hydro Transaction
Witness: Masud

Your testimony mentions one LS Power transaction (that of Safe Harbor) but appears to overlook another significant transaction that has occurred since you last testified, in which First Energy sold 527 MWs of hydro capacity for $395 million to LS Power.

a. Are you aware of this transaction?

b. If you are aware but excluded it from your testimony for some reason, please explain that reason.

RESPONSE:

a. I am aware of the transaction and it was considered in Credit Suisse' evaluation. If you refer to AM Exhibit 1 page 16, it appears as the first transaction listed where the buyer was Harbor Hydro Holdings, LLC, an acquisition entity that LS Power used to purchase the First Energy hydro assets. The transaction involved purchase of 73 MW of run-of-river hydro assets and a 451 MW of a large pumped storage facility (Seneca). Our analysis excluded the pumped storage asset as pumped storage facilities are operationally very different from run-of-river facilities and not comparable.

b. Please see the response to part a, above.

PSC-345

Regarding: AM Exhibit 1 – Unregulated Valuation
Witness: Masud

a. It appears that you are mixing models and using discounted cash flows to evaluate the hydro assets in the first twenty years, but using an EBITDA multiple methodology to evaluate the assets in the following years. Please explain why a sample of EBITDA multiples used to estimate the current values of companies or acquisitions should be used to derive a terminal value EBITDA multiple without significant discounting to remove the first twenty years of value from the multiple.

b. It appears that you assumed base case EBITDA of $45 million annually for the hydro assets in 2014 and 2015 (see Footnote 1 on p. 10 of AM Exhibit 1). Applying this EBITDA to a multiple of 10, a multiple that is larger than any of the median multiples for Canadian and US IPP's seen on p. 15 of AM Exhibit 1, gives a valuation of $450 million. Do you believe this to be a fair estimate of the current value of the hydro assets to an IPP? Please explain why or why not.

c. A purchase price of $900 million divided by $45 million gives an implied EBITDA multiple of 20. Are EBITDA multiples of this magnitude commonly observed in the valuation or acquisition of resources or enterprises? Please provide examples.

d. Rows 100-131 of the "Hydro DCF" tab of the unregulated spreadsheet analysis you provided in response to MCC-093 show proportions of present terminal value to total enterprise value of 30% to 32%, using a terminal EBITDA multiple of 7.5 and discount rates of 7.5%, 7.0%, and 6.5%. Is it typical for an IPP or other unregulated entity to estimate a reasonable purchase price for an acquisition where 30% or more of the price is not covered by the present value of the first twenty years of expected cash flows? Could you provide examples of this nature?

RESPONSE:

a. The use of estimated terminal value for generation assets, including hydro assets at the end of a forecast period, is very standard practice in estimating the valuation range for such assets if the subject assets are deemed to have useful economic life beyond the projected cash flow forecast. Terminal value is a proxy for future cash flow beyond the forecast period and is an important aspect of valuation for assets with very long useful lives such as the hydro assets. The use of observable and publicly available EBITDA multiples based on comparable companies or comparable acquisitions, if available, is also standard and acceptable practice in valuation of assets and is not mixing models.

PSC-345 cont'd

As discussed in my Prefiled Direct Testimony and my Prefiled Rebuttal testimony, Credit Suisse used multiple approaches in estimating the terminal value of the Hydro Assets given that there were no comparable publicly traded companies with exactly similar assets. One of those approaches was to apply an observable EBITDA multiple for IPPs. The average 2014E EBITDA for the IPPs was 10.5x. The average 2014E EBITDA multiple of "Clean generation IPP comps" was 11.9x (page 15 of AM Exhibit 1). Credit Suisse also considered a long-term IPP trading history on a 1 year forward EV/EBITDA multiples basis which showed a long-term average multiple of 7.4x. Based on this available information, Credit Suisse used a range of 7.5x – 8.5x as exit terminal multiples in our DCF analysis even though the then-current spot trading multiples were significantly higher as discussed above.

In addition, to further inform our analysis of terminal multiples, Credit Suisse used $/kW multiples range of $1,650 – $2,150 based on comparable acquisitions analysis (page 16 of AM Exhibit 1).

The discounting the multiples to remove cash flow for assets that have long remaining useful life after the forecast period would be inappropriate.

b. I do not believe that $450 million to be a fair estimate of the current value of the hydro assets to an IPP. I don't agree with the methodology of applying a multiple to just one year's EBITDA as the sole way to value hydro assets. The use of a variety of methodologies including discounted cash flow analysis, comparable acquisition analysis and, to the extent trading multiples of companies that are deemed to be comparable are available, a comparable company analysis would be the appropriate way to value assets.

c. EBITDA of this magnitude i.e., 20x, is periodically observed in generation asset transactions. Some of the examples with public disclosure of EBITDA or multiple of EBITDA include the following:

- Public Service of Colorado, a utility subsidiary of Xcel, purchased 931MW of gas fired assets from Calpine for $739 million. Transaction was announced on April 4, 2010. Calpine, in its April 21, 2010 analyst call, disclosed that the EBITDA multiple was 19x. These assets were rate based by PSCo.
- Oglethorpe purchased 1,220MW CCGT facility from KGen Power Corp. for $531 million. In its proxy to its shareholders in February 2011, KGen disclosed the EBITDA of the facility at $30 million implying an EBITDA multiple of 17.6x. This asset was rate based by Oglethorpe.

PSC-345 cont'd

- Entergy Arkansas purchased 450MW CCGT from KGen Power Corp for $206 million. In its proxy to its shareholders in April 2011, KGen disclosed the EBITDA of negative $19 million. While the EBITDA multiple is not meaningful, please note that KGen received positive value implying $458/kW value for an asset with negative EBITDA. This asset was rate based by Entergy AR.
- Entergy Mississippi purchased 620MW CCGT from KGen Power Corp for $253 million. In its proxy to its shareholders in April 2011, KGen disclosed the EBITDA of negative $7 million. While the EBITDA multiple is not meaningful, please note that KGen received positive value implying $408/kW value for an asset with negative EBITDA. This asset was rate based by Entergy MS.

d. This level of information is typically not disclosed by public or private companies. Therefore, I cannot provide examples of this nature where this level of detail is publicly disclosed. I can however say, based on my experience in advising clients, that the use of a long-term forecast (15 to 20 years or even longer) is provided in the confidential information packages in connection with the sale processes and that terminal values at the end of the forecast drive significant portion of overall valuation. Recent examples of such transactions include:

1. Sale of Midland Cogeneration Ventures (a 1,600 MW cogeneration facility located in Michigan) in 2012 where Credit Suisse prepared an information memorandum that contained forecast from 2012 to 2030 (18 years)
2. Sale of Brooklyn Navy Yard (a 550MW cogeneration facility located in New York) in 2012 where Credit Suisse prepared an information memorandum that contained forecast from 2012 – 2036 (24 years)

Given that access to the information in the above-referenced transactions were granted once potential buyers signed confidentiality agreements, Credit Suisse is not in a position to disclose further details.

PSC-346

Regarding: Unregulated Value Compared to Purchase Price
Witness: Masud

a. Applying EBITDA of $60 million – a 33% increase from base case EBITDA – to an apparently generous EBITDA multiple of 10, produces a $600 million estimate of acquisition value. NorthWestern's proposed purchase price is $900 million, a 50% increase over the EBITDA based estimate. Should the Commission consider this $300 million difference to be a premium assessed to buyers who demonstrate extreme risk aversion, absence of time preference, and attraction to resources in excess of their commercial value? Please explain.

b. Is a 50% premium over the competitive price a standard outcome when regulated utilities with captive customers are purchasing assets from IPP's? Please provide examples if you have them.

c. Should the Commission be concerned about the impact on Montana's economic development that may result from a purchase price in excess of market value that transfers capital from NorthWestern's customers to out-of-state shareholders?

RESPONSE:

a. I agree with the math, i.e., $60 million multiplied by 10x equals $600 million. However, I don't agree with the methodology of applying a multiple to just one year's EBITDA as the sole way to value hydro assets, especially using arbitrarily generated data such as $60 million EBITDA referenced in the question above.

I previously stated in my testimony that Credit Suisse used discounted cash flow analysis with terminal value driven by (i) EBITDA multiples range based on a long-term historical trading average of IPPs and (ii) $/kW multiples range using comparable transactions multiples of $1,650 - $2,150/kW (based on data available publicly). In addition, Credit Suisse valued the business based on $/kW multiples of comparable transactions involving run-of-river hydro assets (please refer to AM Exhibit 1 for the detailed analysis). The purchase price of $900 million was within the valuation ranges that Credit Suisse calculated on an unregulated basis. In addition, NorthWestern received a fairness opinion from a third party (Blackstone) as an additional measure of caution to arrive at the purchase price which reflected fair market value of the Hydro assets. Therefore, in my view there is no excess over "commercial value" paid by NorthWestern and the Commission should not view the $300 million stated above as a "premium."

PSC-346 cont'd

b. I cannot comment on whether any regulated utilities would pay a premium over "competitive price." However, I will say that there are a number of examples where regulated utilities have paid fair market value for purchase of assets (which were rate based) at prices deemed attractive to IPP sellers. Following is a list of a few examples of such transactions involving fossil assets (CCGTs, CT and coal) over the last few years:

- UniSource' acquisition of 550MW from Entegra for $400/kW (12/26/13)
- PNM Resources acquisition of 132 MW CT from Arclight for $303/kW (12/11/12)
- Salt River's acquisition of 594 MW CCGT from Sempra for $600/kW (11/6/12)
- Wisconsin Public Service acquisition of 593MW CCGT from GE for $742/kW (9/28/12)
- Wisconsin Power & Light's acquisition of 600MW CCGT from Calpine for $650/kW (5/11/12)
- TVA's acquisition of 968MW CCGT from Kelson for $450/kW (7/6/11)
- Entergy Arkansas purchase of 620MW CCGT from KGen Power for $408/kW (4/28/11)
- Entergy Mississippi purchase of 450MW CCGT from KGen Power for $458/kW (4/28/11)
- Arizona Public Service acquisition of 713MW coal from SCE for $412/kW
- Rayburn County Electric Coop acquisition of 259MW CCGT from Calpine for 830/kW (10/27/10)
- Oglethorpe's acquisition of 1,220 MW CCGT from KGen for $435/kW (10/26/10)
- Public Service of Colorado's (Xcel) acquisition of 931 MW portfolio of CCGT/CT from Calpine from $794/kW (4/5/2010)

c. NorthWestern is paying market value, i.e., a price agreed upon by a willing buyer and a willing seller. In addition, the purchase price of $900 million is within the valuation ranges calculated by Credit Suisse using various valuation methodologies that are commonly used to value such assets as detailed in AM Exhibit 1. Furthermore, NorthWestern received an independent third party fairness opinion from Blackstone before entering into a transaction with PPL.

PSC-347
Regarding: AM Exhibit 1 – Regulated Valuation
Witness: Masud

Regarding the implied 2014-2015 EV/EBITDA multiples of 7.8 to 9.1 found in the "DCF (EBITDA multiple driven)" regulated valuation summary on p. 11 of AM Exhibit 1; since EBITDA for a regulated entity is directly related to the value in rate base, it appears that a narrow range of implied EBITDA multiples is consistent with a broad range of initial purchase prices. For instance, in the NorthWestern revenue requirements model (Meyer); an initial purchase price of $469 million implies a 2014 EBITDA multiple of about 8.6, a purchase price of $689 million gives a multiple of 8.4, $900 million a multiple of 8.3, and $1.128 billion a multiple of 8.2. Do you agree with this general pattern? Please explain how the implied EBITDA multiples are useful when a range of purchase prices from $470 million to $1.1 billion implies multiples from 8.2 to 8.6.

RESPONSE:

I agree with the general pattern discussed in the question above. Credit Suisse analyses, as presented in AM Exhibit 1, valued the cash flows expected to be generated by the Hydro Assets per the revenue requirement model developed by NorthWestern. We did not amend or modify the base case provided to Credit Suisse as the "management financial projections", i.e., we did not run the sensitivities to purchases prices of $470 million to $1.1 billion referenced in the question above.

The implied valuation multiples serve as a quick reference guide on implied multiples of EBITDA based on forward year 1 and forward year 2 and also $/kw valuation implied by the ranges of values calculated based on all analyses conducted. Using the 8.2x – 8.6x range referenced above, the implied valuation of the hydro assets would be $911mm - $954mm.

Please note that the same output of implied multiples was presented on page 10 of AM Exhibit 1 (Mustang Unregulated valuation summary) for consistency of summary outputs across our presentation to NorthWestern.

NorthWestern Energy
Docket D2013.12.85
PPLM Hydro Assets Purchase

Public Service Commission (PSC)
Set 14 (305-354)

Data Requests served May 23, 2014

PSC-348
Regarding: Current Valuation
Witness: Masud

On 3:17-19 of your rebuttal testimony you state that you believe $1,500 per kW is a reasonable valuation for an on-going hydroelectric generation business. Do you believe that $659 million (439 * $1,500 = $658,500) would be a reasonable amount to enter into rate base for the acquisition of the hydro assets sans Kerr? Please explain.

RESPONSE:

No. $659 million would not be a reasonable amount to enter into rate base for the acquisition of the hydro assets.

The acquisition price agreed with the seller is $900 million (including Kerr). NorthWestern arrived at this price after careful consideration of many factors including, but not limited to, the fair value of the assets on merchant basis, the customer rate impact, stability of long-term supply cost for NorthWestern customers, and physical condition of the assets, etc. In addition, NorthWestern negotiated this transaction, including price and terms, in good faith and in an arms-length transaction with PPL Corp.

The reference to 3:17-19 of my rebuttal testimony misstates my testimony. I urge the readers of PSC-348 to read my Prefiled Rebuttal testimony in its entirety just so that no one statement made in the testimony is taken out of context which I believe the question stated above implies.

PSC-349
Regarding: Comparable Acquisition Analysis
Witness: Masud

On p. 16 of AM Exhibit 1 you have listed select precedent hydro transactions and a few relevant variables, including total price and price per kilowatt but not EBITDA. Since price per kilowatt does not provide insight into the expected cost and revenue streams relevant to these assets, how can the Commission compare their perceived market value to the value of PPLM's hydro assets without access to EBITDA or other references to expected financial performance? Please provide EBITDA multiples or other performance references if you have any.

RESPONSE:

While generation assets have different operating and other characteristics, price per kW is a commonly used and accepted metric when comparing the value of assets with similar fuel types/technologies or comparing one set of run-of-river assets to others.

The purpose of analysis shown on page 16 of AM Exhibit 1 labeled "Comparable acquisition analysis" is to highlight publicly available information regarding transactions that Credit Suisse deems to be relevant. In certain cases, Credit Suisse also adjusted the publicly announced price for data that was publicly available to make the comparison more comparable and footnoted all such adjustments. In none of these transactions the EBITDA or other references to expected financial performance were publicly disclosed. Therefore, no further information on EBITDA or other performance references could be provided.

PSC-350
Regarding: Exhibit _(PJD-7)
Witness: DiFronzo

In the rebuttal testimony of Patrick DiFronzo the Exhibit_(PJD-7) provides a typical customer bill calculation to reflect the new revenue requirement which removes any return on Kerr and changes the depreciation schedule of the hydro assets from a 40 year life to a 50 year life. Please update the Exhibit_(PJD-7) with a projected rate column as of 07/01/2014.

RESPONSE:

Please see the response to Data Request PSC-351.

PSC-351
Regarding: Update to Residential Bill Impact Worksheet
Witness: DiFronzo

NWE representatives at a recent listening session postulated that in January 2015 the difference between a typical residential customer's bill without the Hydros vs. one with the Hydros would be substantially less than the 8.9% calculated in response to DR PSC- 034, because of the modifications made in NWE's rebuttal testimony. Please provide an updated answer to PSC-034.

RESPONSE:

See the two files in the folder labeled "PSC-351" on the CD attached to PSC-315. The "PSC-351 Bill Impact" file reflects the projected residential bill impacts and the "PSC-351 Electric Supply Rates" file provides the support for the estimated supply rates without the PPLM hydro assets for the period July 2014, January 2015 and July 2015. I have also provided these files as paper attachments.

Please note that Exhibit__(PJD-7) was based on using the rebuttal revenue requirement of $120.9 million as shown on Exhibit__(PJD-5). This updated revenue requirement amount is $7.4 million less than the original revenue requirement amount used in Exhibit__(PJD-1). This reduction is the result of the removal of the return on Kerr and changing the depreciation schedule of the hydro assets from a 40-year life to a 50-year life. The rate design for the comparison to the hydro assets was updated to reflect the current 12-month forecast market and other electricity costs such as DSM lost revenues, DSM program costs, administrative and general, etc., as reflected in the annual supply tracker filing in Docket No. D2014.5.46, for rates effective July 1, 2014.

The proposed supply rates at July 1, 2014 are based on NorthWestern Energy proposed rates from the annual electric supply tracker filing in Docket No. D2014.5.46. These rates also reflect the proposed rates for the deferred supply costs and the CTC-QF that would also be effective on July 1, 2014 after Commission approval.

NorthWestern Energy

Typical Bill Calculation

Electric Residential Service

	Without PPL Hydro Assets		*With PPL Hydro Assets*		*Without Hydro Assets*		*Without Hydro Assets*	
kWh per month **750**								
	Proposed Rates[1] 7/1/2014	Total Bill Amount	**Projected Rates 10/1/2014**	Total Bill Amount	**Projected Rates 1-Jan-15**	Total Bill Amount	**Projected Rates 1-Jul-15**	Total Bill Amount
Res. Dist.-Service Charge	$ 5.25	$ 5.25	$ 5.25	$ 5.25	$ 5.25	$ 5.25	$ 5.25	$ 5.25
Plus:								
Res. Supply-Energy	**$ 0.062451**	$ 46.84	**$ 0.069313**	$ 51.98	**$ 0.062252**	$ 46.69	**$ 0.063236**	$ 47.43
Res. Deferred Supply Costs	$ 0.005369	$ 4.03	$ 0.005369	$ 4.03	$ 0.005369	$ 4.03	$ 0.005369	$ 4.03
Res. CTC-QF	$ 0.003325	$ 2.49	$ 0.003325	$ 2.49	$ 0.003325	$ 2.49	$ 0.003325	$ 2.49
Res. Transmission-Energy	$ 0.009165	$ 6.87	$ 0.009165	$ 6.87	$ 0.009165	$ 6.87	$ 0.009165	$ 6.87
Res. Distribution-Energy	$ 0.028529	$ 21.40	$ 0.028529	$ 21.40	$ 0.028529	$ 21.40	$ 0.028529	$ 21.40
Res. USBC	$ 0.001334	$ 1.00	$ 0.001334	$ 1.00	$ 0.001334	$ 1.00	$ 0.001334	$ 1.00
Res. BPA-Credit	$ (0.006810)	$ (5.11)	$ (0.006810)	$ (5.11)	$ (0.006810)	$ (5.11)	$ (0.006810)	$ (5.11)
Total Kwh Charge	$ 0.103363	$ 77.52	$ 0.110225	$ 82.66	$ 0.103164	$ 77.37	$ 0.104148	$ 78.11
Total Bill	**$ 0.110363**	**$ 82.77**	**$ 0.117225**	**$ 87.91**	**$ 0.110164**	**$ 82.62**	**$ 0.111148**	**$ 83.36**
	Monthly Increase (Decrease)			$ 5.14		$ (0.15)		$ 0.59
	Annual Increase (Decrease)			$ 61.68		$ (1.80)		$ 7.08
	Percent Change			**6.21%**		**-0.18%**		**0.71%**

[1] Proposed Supply-Energy and Deferred Supply Costs based on Annual Electric Supply Tracker Filing Docket No. D2014.5.46.

NorthWestern Energy
Electric Utility
Total Estimated Electric Supply Rate
PPLM Hydro Assets Purchase
Year 2014 With Hydro

	B	D	F	H	J	L	N	P	R	T
1										
2										
3										
4										
5	NorthWestern Energy									
6	Electric Utility									
7	Total Estimated Electric Supply Rate									
8	PPLM Hydro Assets Purchase									
9	Year 2014 With Hydro									
10										
11		**Estimated**	**Colstrip Unit 4**		**Dave Gates Gen Station**		**Spion Kop**		**PPL Hydro Assets**	
12		**Electric**	**Current**	**Current**	**Current**	**Current**	**Current**	**Current**	**Estimated**	**Estimated**
13		**Supply**	**Fixed**	**Variable**	**Fixed**	**Variable**	**Fixed**	**Variable**	**Fixed**	**Total Supply**
14		**Rates [1]**	**Rates [2]**	**Rates [3]**	**Rates [4]**	**Rates [5]**	**Rates [6]**	**Rates [7]**	**Rates [8]**	**Rates**
15	**Residential**									
16	Residential	0.023662	0.012734	0.004374	0.004795	0.002018	0.001458	0.000003	0.020269	0.069313
17	Residential Employee	0.014196	0.007640	0.002625	0.002877	0.001212	0.000875	0.000002	0.012161	0.041588
18	Total Residential									
19										
20	**General Service 1**									
21	GS-1 Sec Non-Demand	0.021406	0.012734	0.004374	0.004795	0.002018	0.001459	0.000003	0.020269	0.067058
22	GS-1 Sec Demand	0.023662	0.012734	0.004374	0.004795	0.002018	0.001459	0.000003	0.020269	0.069314
23	GS-1 Pri Non-Demand	0.023012	0.012385	0.004254	0.004664	0.001963	0.001420	0.000003	0.019714	0.067415
24	GS-1 Pri Demand	0.021013	0.012385	0.004254	0.004664	0.001963	0.001420	0.000003	0.019714	0.065416
25	Total GS-1									
26										
27	**General Service 2**									
28	GS-2 Substation	0.022815	0.012278	0.004218	0.004624	0.001946	0.001407	0.000003	0.019544	0.066835
29	GS-2 Transmission	0.022678	0.012204	0.004192	0.004596	0.001934	0.001399	0.000003	0.019426	0.066432
30	Total GS-2									
31										
32	**Irrigation**									
33	Irrigation	0.021406	0.012734	0.004374	0.004795	0.002018	0.001459	0.000003	0.020269	0.067058
34	Total Irrigation									
35										
36	**Lighting**									
37	Lighting	0.021406	0.012734	0.004374	0.004795	0.002018	0.001459	0.000003	0.020269	0.067058
38	Total Lighting									
39										
40	**Average Billed Rate**	**0.023279**	**0.012681**	**0.004356**	**0.004775**	**0.002010**	**0.001453**	**0.000003**	**0.020184**	**0.068741**
41										
42	**Total Supply Rate**	**23.279**		**17.037**		**6.785**		**1.456**	**20.184**	**68.741**
43										
44	[1] Source: Page 3 Attached with the hydro assets.									
45	[2] Source: Fixed rates approved in Docket No. D2010.5.50 Order No. 7093c, effective 04/01/2010.									
46	[3] Source: Annual Electric Supply Tracker Filing Docket No. D2014.5.46									
47	[4] Source: Fixed rates (based on 2nd yr rev req) approved in Docket No. D2008.8.95 Order No.6943e, effective 01/01/2012.									
48	[5] Source: Annual Electric Supply Tracker Filing Docket No. D2014.5.46									
49	[6] Source: Fixed rates (based on 2nd yr rev req) approved in Docket No. D2011.5.41 Order No.7159i, effective 1/1/2014.									
50	[7] Source: Annual Electric Supply Tracker Filing Docket No. D2014.5.46									
51	[8] Source: Page 2 Attached PPLM Hydro Assets Revenue Requirement.									

	A	B	C	D	E	F	G	H	I	J	K	L	M
1													
2													
3													
4													
5		**NorthWestern Energy**											
6		**PPLM Hydro Assets Purchase**											
7													
8		**Derivation of Rates**											
9		**12 Months Ended December 2014**											
10													
11													
12						**Jul14 to Jun15**		**Sales Adjusted**			**Electric**		**Electric**
13				**Loss**		**Supply Retail**		**for Employee**		**Sales Weighted**	**Supply Rate**		**Supply Revenue**
14				**Factor**		**kWh Sales**		**Discount**		**by Losses**	**After Losses**		**Check**
15		**Customer Rate Class**											
16		Residential		8.5100%		2,382,946,204		2,382,946,204		2,585,734,926	$ 0.020269		$ 48,299,937
17		Residential Employee		8.5100%		3,488,614		2,093,168		2,271,297	$ 0.012161		$ 42,425
18		GS 1 Secondary NonDemand		8.5100%		281,285,585		281,285,585		305,222,988	$ 0.020269		$ 5,701,378
19		GS 1 Secondary Demand		8.5100%		2,447,309,441		2,447,309,441		2,655,575,475	$ 0.020269		$ 49,604,515
20		GS 1 Primary NonDemand		5.5400%		558,086		558,086		589,004	$ 0.019714		$ 11,002
21		GS 1 Primary Demand		5.5400%		359,164,093		359,164,093		379,061,784	$ 0.019714		$ 7,080,561
22		General Service Substation		4.6300%		232,644,116		232,644,116		243,415,538	$ 0.019544		$ 4,546,797
23		General Service Transmission		4.0000%		132,058,402		132,058,402		137,340,738	$ 0.019426		$ 2,565,367
24		Irrigation		8.5100%		93,661,183		93,661,183		101,631,750	$ 0.020269		$ 1,898,419
25		Lighting		8.5100%		59,884,934		59,884,934		64,981,141	$ 0.020269		$ 1,213,808
26						5,993,000,659		5,991,605,213		6,475,824,643	$ 0.020189		$ 120,964,207
27		YNP Contract				18,731,652					Rounding Adjustment		$ (516)
28		Total Electric Supply Load				6,011,732,311							$ 120,963,690
29													
30													
31								PPLM Hydro Assets Purchase - 2014 Revenue Requirement		$ 120,963,690			
32								less: YNP Contract Revenues		$ -			
33								Supply Excluding Generation Assets Rate Design Revenues		$ 120,963,690			
34													
35								**Electric Supply Cost Rate Before Losses**		**$ 0.018679**			
36								**Electric Supply Cost Rate After Losses**		**$ 0.020184**			

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1															
2															
3															
4															
5		**NorthWestern Energy**													
6		**Electric Utility Derivation of Rates**													
7		**Electricity Supply Excluding Generation Assets - Prior to Cap Adjustment**													
8		**Tracker Period 2014**													
9															
10															
11						**Jul14 to Jun15**		**Sales Adjusted**				**Electricity**		**Electricity**	
12				**Loss**		**Supply Retail**		**for Employee**		**Sales Weighted**		**Supply Rate**		**Supply Revenue**	
13				**Factor**		**kWh Sales**		**Discount**		**by Losses**		**After Losses**		**Check**	
14		**Customer Rate Class**													
15		Residential		8.5100%		2,382,946,204		2,382,946,204		2,585,734,926		$ 0.023377		$ 55,706,133	
16		Residential Employee		8.5100%		3,488,614		2,093,168		2,271,297		$ 0.014026		$ 48,931	
17		GS 1 Secondary NonDemand		8.5100%		281,285,585		281,285,585		305,222,988		$ 0.023377		$ 6,575,613	
18		GS 1 Secondary Demand		8.5100%		2,447,309,441		2,447,309,441		2,655,575,475		$ 0.023377		$ 57,210,753	
19		GS 1 Primary NonDemand		5.5400%		558,086		558,086		589,004		$ 0.022738		$ 12,690	
20		GS 1 Primary Demand		5.5400%		359,164,093		359,164,093		379,061,784		$ 0.022738		$ 8,166,673	
21		General Service Substation		4.6300%		232,644,116		232,644,116		243,415,538		$ 0.022541		$ 5,244,031	
22		General Service Transmission		4.0000%		132,058,402		132,058,402		137,340,738		$ 0.022406		$ 2,958,901	
23		Irrigation		8.5100%		93,661,183		93,661,183		101,631,750		$ 0.023377		$ 2,189,517	
24		Lighting		8.5100%		59,884,934		59,884,934		64,981,141		$ 0.023377		$ 1,399,930	
25						5,993,000,659		5,991,605,213		6,475,824,643		$ 0.023285		$ 139,513,173	
26		YNP Contract				18,731,652						Rounding Adjustment		$ 3,689	
27		Total Electricity Supply Load				6,011,732,311								$ 139,516,862	
28															
29															
30		Electricity Supply Excluding Generation Assets Costs (Ref Line 52)								$ 140,721,307					
31								less: YNP Contract Revenues		$ (1,204,445)					
32		**Electricity Supply Excluding Generation Assets Rate Design Revenues**								**$ 139,516,862**					
33															
34								Electricity Supply Cost Rate Before Losses		$ 0.021544					
35								Electricity Supply Cost Rate After Losses		$ 0.023279					
36															
37		YNP Contract Load				18,731,652									
38		YNP May14-Apr15 Contract Supply Rate				0.064300									
39		YNP Supply Revenue				$ 1,204,445									
40															
41															
42		**Electric Supply Costs for period October 2014 through September 2015**													
43		Net Market Purchase Costs (Reference Page 5 Line 110)								$ 196,769,939					
44		DSM Lost Revenues	1							$ 7,564,633					
45		DSM Program Costs	1							$ 8,835,366					
46		Wind Other Costs	1							$ 1,810,052					
47		Carrying Costs	1							$ 1,422,086					
48		Adm & General	1							$ 1,930,703					
49		Transmission	1							$ 602,155					
50		**Total Supply Tracker Costs Excluding Generation Cost of Service**								$ 218,934,934					
51															
52		Remove Spot Purchases With Mustang								$ (67,538,324)					
53		Remove Terminated PPL Contract								$ (10,849,120)					
54		Add Spot Purchases With PPLM Hydro Assets Purchase								$ 173,817					
55		**Total Electric Supply Costs**								$ 140,721,307					
56															
57															
58		[1]Based on Annual Electric Monthly Supply Tracker Filing D2014.5.46													

NorthWestern Energy
Electric Utility Derivation of Rates
Electricity Supply Excluding Generation Assets Capped at Residential Increase
Revenues ($000)
Tracker Period Oct. 2014 - Sept 15

Row	B	D	F	H	J	L	N	P	R	T	V
11		Jul14 to Jun15									
12		Supply Retail	Current	Proposed	Proposed			$ at Res Cap	Capped	Capped	Capped
13	CAPPED RATES	kWh Sales	Revenue	Rates	Revenue	$ Change	% Change	-37.71%	$ Change	% Change	kWh Rates
14	**Residential**										
15	Residential	2,382,946	$ 89,434	$ 0.023377	$ 55,706	$ (33,728)	-37.71%	$ 55,706	$ 56,385	-36.95%	$ 0.023662
16	Res Employee	3,489	$ 79	$ 0.014026	$ 49	$ (30)	-37.71%	$ 49	$ 50	-36.96%	$ 0.014196
17	Total Residential	2,386,435	$ 89,513		$ 55,755	$ (33,758)	-37.71%	$ 55,755	$ 56,435	-36.95%	
18	**General Service 1**										
19	GS1 Sec NonDmd	281,286	$ 9,550	$ 0.023377	$ 6,576	$ (2,975)	-31.15%	$ 5,949	$ 6,021	-36.95%	$ 0.021406
20	GS1 Sec Dmd	2,447,309	$ 91,850	$ 0.023377	$ 57,211	$ (34,639)	-37.71%	$ 57,211	$ 57,908	-36.95%	$ 0.023662
21	GS1 Prim NonDmd	558	$ 20	$ 0.022738	$ 13	$ (8)	-37.70%	$ 13	$ 13	-36.95%	$ 0.023012
22	GS1 Prim Dmd	359,164	$ 11,971	$ 0.022738	$ 8,167	$ (3,804)	-31.78%	$ 7,456	$ 7,547	-36.95%	$ 0.021013
23	Total GS-1	3,088,317	$ 113,392		$ 71,966	$ (41,426)	-36.53%	$ 70,629	$ 71,489	-36.95%	
24	**General Service 2**										
25	GS2 Substation	232,644	$ 8,419	$ 0.022541	$ 5,244	$ (3,175)	-37.71%	$ 5,244	$ 5,308	-36.95%	$ 0.022815
26	GS2 Transmission	132,058	$ 4,750	$ 0.022406	$ 2,959	$ (1,791)	-37.71%	$ 2,959	$ 2,995	-36.95%	$ 0.022678
27	Total GS-2	364,703	$ 13,169		$ 8,203	$ (4,966)	-37.71%	$ 8,203	$ 8,303	-36.95%	
28	**Irrigation**										
29	Irrigation	93,661	$ 3,180	$ 0.023377	$ 2,190	$ (991)	-31.15%	$ 1,981	$ 2,005	-36.95%	$ 0.021406
30	Total Irrigation	93,661	$ 3,180		$ 2,190	$ (991)	-31.15%	$ 1,981	$ 2,005	-36.95%	
31	**Lighting**										
32	Lighting	59,885	$ 2,033	$ 0.023377	$ 1,400	$ (633)	-31.15%	$ 1,266	$ 1,282	-36.95%	$ 0.021406
33	Total Lighting	59,885	$ 2,033		$ 1,400	$ (633)	-31.15%	$ 1,266	$ 1,282	-36.95%	
34											
35	Total Rate Schedule	5,993,001	$ 221,287		$ 139,513	$ (81,774)	-36.95%	$ 137,833	$ 139,513		
36		-							-		
37	Capped Rate Adjustment Factor							0.012187			
38											

Electric Supply Cost Tracker
Electric Tracker Projection

Volumes in MWh	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Total
	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
Off System Transactions													
Fixed Price													
Base Fixed Price Purchases													
Competitive Solicitations	114,600	109,325	113,800	39,400	36,000	39,375	38,800	38,600	38,800	39,400	39,400	38,000	685,500
Base Fixed Price Sales													
Competitive Solicitations	-	-	-	-	-	-	-	-	-	-	-	-	-
Term Fixed Price Purchases	32,400	28,800	31,200	66,200	60,000	66,125	64,400	65,800	64,400	66,200	66,200	64,000	675,725
Term Fixed Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Index Price													
Base Index Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Base Index Price Sales													
Competitive Solicitations	(29,400)	(27,625)	(29,000)	(29,000)	(26,400)	(28,975)	(28,400)	(28,600)	(28,400)	(10,400)	(10,400)	(10,000)	(286,600)
Term Index Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Term Index Price Sales	(74,400)	(72,100)	(74,400)	-	-	-	-	-	-	-	-	-	(220,900)
Spot Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Sales	(43,200)	(38,400)	(41,600)	(76,600)	(69,600)	(76,525)	(74,800)	(75,800)	(74,800)	(95,200)	(95,200)	(92,000)	(853,725)
On System Transactions													
Fixed Price													
Rate Based Assets													
Colstrip Unit 4	150,288	145,440	150,288	150,288	135,744	150,086	145,440	150,288	145,440	150,288	150,288	145,440	1,769,318
Dave Gates Generating Station	5,208	5,040	5,208	5,208	4,704	5,208	5,040	5,208	5,040	5,208	5,208	5,040	61,320
Spion Kop	14,136	14,400	11,904	17,856	10,752	11,888	11,520	8,928	8,640	8,184	8,184	9,360	135,752
Base Fixed Price Purchases													
Judith Gap	42,916	48,042	55,493	59,351	43,179	42,828	40,523	35,181	28,766	22,786	25,190	27,631	471,885
Other Small PPAs	5,490	3,605	3,720	3,720	3,360	3,715	3,600	8,355	11,967	12,403	10,802	6,744	77,482
Competitive Solicitations	21,600	19,200	20,800	20,800	19,200	20,800	20,800	20,000	20,800	20,800	20,800	20,000	245,600
QF Tier II	70,792	72,882	76,390	72,237	65,514	75,487	74,522	75,031	57,153	59,154	60,334	67,568	827,066
QF Tier II Adjustments													
QF-1 Tariff	14,225	16,214	16,740	18,228	13,776	14,489	12,709	13,671	10,801	10,373	11,160	11,475	163,860
Term Fixed Price Purchases	2,025	1,800	1,950	-	-	-	-	-	-	-	-	-	5,775
Term Fixed Price Sales	(2,025)	(1,800)	(1,950)	-	-	-	-	-	-	-	-	-	(5,775)
Index Price													
Base Index Price Purchases													
Basin Creek	4,768	5,879	10,691	4,727	3,265	4,050	1,258	835	1,132	6,525	13,271	9,153	65,555
Competitive Solicitations	45,000	44,475	45,400	29,000	26,400	28,975	28,400	28,600	28,400	10,400	10,400	10,000	335,450
Term Index Price Purchases	123,600	112,850	120,400	37,200	33,600	37,150	36,000	37,200	36,000	37,200	37,200	36,000	684,400
Term Index Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Purchases	42,824	50,790	101,525	201,598	198,584	162,043	119,734	120,573	158,952	255,019	222,700	146,954	1,781,295
Spot Sales	(27,931)	(1,940)	(2,948)	(13,027)	(19,923)	(21,287)	(9,524)	(4,961)	(3,020)	(5,242)	(5,887)	(5,628)	(121,318)
Imbalance, Current Month Estim	-	-	-	-	-	-	-	-	-	-	-	-	-

Imbalance, Prior Month True-up	-	-	-	-	-	-	-	-	-	-	-	-	-
Imbalance, Accounting & BA Exp	-	-	-	-	-	-	-	-	-	-	-	-	-
Ancillary and Other													
Basin Creek Fixed Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
Basin Creek Variable Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Other Cost													
DSM Program & Labor Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM Lost T& D Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM Lost Revenue Adjustment													
Total Delivered Supply	512,917	536,877	615,611	607,186	538,154	535,432	490,023	498,908	510,071	593,098	569,649	489,736	6,497,665

Electric Tracker Projection Excluding Generation Assets Cost of Service
Total Supply Expense

	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Total
	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
Off System Transactions													
Fixed Price													
Base Fixed Price Purchases													
Competitive Solicitations	$ 5,065,860	$ 4,776,260	$ 5,004,440	$ 2,314,000	$ 2,112,960	$ 2,312,440	$ 2,276,560	$ 2,269,640	$ 2,276,560	$ 2,314,000	$ 2,314,000	$ 2,232,200	$ 35,268,920
Base Fixed Price Sales													
Competitive Solicitations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Term Fixed Price Purchases	$ 1,311,660	$ 1,165,920	$ 1,263,080	$ 2,390,810	$ 2,173,800	$ 2,388,569	$ 2,337,020	$ 2,362,990	$ 2,337,020	$ 2,390,810	$ 2,390,810	$ 2,309,200	$ 24,821,689
Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Index Price													
Base Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Base Index Price Sales													
Competitive Solicitations	$ (1,168,464)	$ (1,165,520)	$ (1,419,174)	$ (1,222,602)	$ (1,062,360)	$ (1,164,461)	$ (744,000)	$ (674,668)	$ (682,328)	$ (450,736)	$ (449,176)	$ (431,400)	$ (10,634,889)
Term Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Term Index Price Sales	$ (2,881,056)	$ (2,959,039)	$ (3,544,696)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (9,384,791)
Spot Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Spot Sales	$ (1,792,800)	$ (1,703,040)	$ (2,132,000)	$ (3,355,846)	$ (2,906,496)	$ (3,195,684)	$ (2,246,992)	$ (2,088,290)	$ (2,060,740)	$ (4,125,968)	$ (4,111,688)	$ (3,968,880)	$ (33,688,424)
On System Transactions													
Fixed Price													
Rate Based Assets													
Colstrip Unit 4													$ -
Dave Gates Generating Station													$ -
Spion Kop													$ -
Base Fixed Price Purchases													
Judith Gap	$ 1,362,569	$ 1,525,322	$ 1,761,904	$ 1,884,400	$ 1,370,923	$ 1,359,803	$ 1,286,618	$ 1,116,985	$ 913,326	$ 723,447	$ 799,775	$ 877,289	$ 14,982,361
Other Small PPAs	$ 260,993	$ 139,694	$ 144,150	$ 144,150	$ 130,200	$ 143,956	$ 139,500	$ 458,139	$ 706,397	$ 732,443	$ 623,955	$ 352,508	$ 3,976,085
Competitive Solicitations	$ 1,166,940	$ 1,037,280	$ 1,123,720	$ 1,123,720	$ 1,037,280	$ 1,123,720	$ 1,123,720	$ 1,080,500	$ 1,123,720	$ 1,123,720	$ 1,123,720	$ 1,080,500	$ 13,268,540

QF Tier II	$ 2,695,776	$ 2,775,365	$ 2,908,947	$ 2,750,791	$ 2,494,761	$ 2,874,549	$ 2,837,803	$ 2,857,191	$ 2,176,390	$ 2,295,176	$ 2,340,969	$ 2,621,630	$ 31,629,350
QF Tier II Adjustments													
QF-1 Tariff	$ 961,133	$ 1,092,522	$ 1,119,069	$ 1,217,139	$ 917,327	$ 971,985	$ 864,631	$ 931,767	$ 740,433	$ 718,097	$ 765,051	$ 779,664	$ 11,078,820
Term Fixed Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Index Price													
Base Index Price Purchases													
Basin Creek	na	na	na	na	na	na	na	na	na	na	na	na	na
Competitive Solicitations	$ 1,616,892	$ 1,694,282	$ 2,026,822	$ 1,201,802	$ 1,043,160	$ 1,143,661	$ 723,200	$ 654,668	$ 661,528	$ 429,936	$ 428,376	$ 411,400	$ 12,035,727
Term Index Price Purchases	$ 4,785,768	$ 4,661,505	$ 5,800,068	$ 1,434,956	$ 1,234,128	$ 1,361,490	$ 768,368	$ 698,136	$ 696,816	$ 1,264,624	$ 1,260,028	$ 1,215,600	$ 25,181,486
Term Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Spot Purchases	$ 1,777,205	$ 2,252,530	$ 5,203,165	$ 8,831,991	$ 8,292,862	$ 6,766,908	$ 3,596,819	$ 3,321,794	$ 4,379,121	$ 11,052,539	$ 9,618,396	$ 6,339,581	$ 71,432,910
Spot Sales	$ (974,233)	$ (72,304)	$ (126,970)	$ (494,635)	$ (721,013)	$ (770,377)	$ (149,336)	$ (71,339)	$ (43,428)	$ (147,720)	$ (165,366)	$ (157,865)	$ (3,894,586)
Imbalance, Current Month Estim	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Imbalance, Prior Month True-up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Imbalance, Accounting & BA Exp	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ancillary and Other													
Basin Creek Fixed Costs	$ 356,738	$ 792,573	$ 361,465	$ 375,308	$ 365,231	$ 353,305	$ 356,450	$ 777,549	$ 354,039	$ 355,755	$ 356,089	$ 361,576	$ 5,166,077
Basin Creek Variable Costs	$ 202,685	$ 257,848	$ 479,817	$ 211,893	$ 146,196	$ 180,150	$ 48,448	$ 31,675	$ 42,907	$ 276,188	$ 567,472	$ 387,307	$ 2,832,586
Operating Reserves	$ 229,152	$ 221,760	$ 229,152	$ 229,152	$ 206,976	$ 229,152	$ 221,760	$ 229,152	$ 221,760	$ 229,152	$ 229,152	$ 221,760	$ 2,698,080
Wind Other Cost													
DSM Program & Labor Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM Lost T& D Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM Lost Revenue Adjustment													
Total Delivered Supply	$ 14,976,818	$ 16,492,958	$ 20,202,958	$ 19,037,030	$ 16,835,935	$ 16,079,166	$ 13,440,569	$ 13,955,888	$ 13,843,521	$ 19,181,464	$ 18,091,563	$ 14,632,070	$ 196,769,939

Electric Tracker Projection Excluding Generation Assets Cost of Service
Unit Costs

	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Total
	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
Off System Transactions													
Fixed Price													
Base Fixed Price Purchases													
Competitive Solicitations	$ 44.20	$ 43.69	$ 43.98	$ 58.73	$ 58.69	$ 58.73	$ 58.67	$ 58.80	$ 58.67	$ 58.73	$ 58.73	$ 58.74	$ 51.45
Base Fixed Price Sales													
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
Term Fixed Price Purchases	$ 40.48	$ 40.48	$ 40.48	$ 36.11	$ 36.23	$ 36.12	$ 36.29	$ 35.91	$ 36.29	$ 36.11	$ 36.11	$ 36.08	$ 36.73
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
Index Price													
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
Base Index Price Sales													
Competitive Solicitations	$ 39.74	$ 42.19	$ 48.94	$ 42.16	$ 40.24	$ 40.19	$ 26.20	$ 23.59	$ 24.03	$ 43.34	$ 43.19	$ 43.14	$ 37.11
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

Term Index Price Sales	$ 38.72	$ 41.04	$ 47.64	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	$ 42.48
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
Spot Sales	$ 41.50	$ 44.35	$ 51.25	$ 43.81	$ 41.76	$ 41.76	$ 30.04	$ 27.55	$ 27.55	$ 43.34	$ 43.19	$ 43.14	$ 39.46
<u>On System Transactions</u>													
Fixed Price													
Rate Based Assets													
Colstrip Unit 4													$ -
Dave Gates Generating Station													$ -
Spion Kop													$ -
Base Fixed Price Purchases													
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
Other Small PPAs	$ 47.54	$ 38.75	$ 38.75	$ 38.75	$ 38.75	$ 38.75	$ 38.75	$ 54.84	$ 59.03	$ 59.05	$ 57.76	$ 52.27	$ 51.32
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
QF Tier II	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.80	$ 38.80	$ 38.80	$ 38.24
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
QF-1 Tariff	$ 67.57	$ 67.38	$ 66.85	$ 66.77	$ 66.59	$ 67.09	$ 68.03	$ 68.16	$ 68.55	$ 69.23	$ 68.55	$ 67.95	$ 67.61
Spot Purchases	$ -	$ -	$ -	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	$ -
Spot Sales	$ -	$ -	$ -	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	$ -
Index Price													
Base Index Price Purchases													
Basin Creek	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
Competitive Solicitations	$ 35.93	$ 38.10	$ 44.64	$ 41.44	$ 39.51	$ 39.47	$ 25.46	$ 22.89	$ 23.29	$ 41.34	$ 41.19	$ 41.14	$ 35.88
Term Index Price Purchases	$ 38.72	$ 41.31	$ 48.17	$ 38.57	$ 36.73	$ 36.65	$ 21.34	$ 18.77	$ 19.36	$ 34.00	$ 33.87	$ 33.77	$ 36.79
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
Spot Purchases	$ 41.50	$ 44.35	$ 51.25	$ 43.81	$ 41.76	$ 41.76	$ 30.04	$ 27.55	$ 27.55	$ 43.34	$ 43.19	$ 43.14	$ 40.10
Spot Sales	$ 34.88	$ 37.27	$ 43.07	$ 37.97	$ 36.19	$ 36.19	$ 15.68	$ 14.38	$ 14.38	$ 28.18	$ 28.09	$ 28.05	$ 32.10
Imbalance, Current Month Estim	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
Imbalance, Prior Month 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
Imbalance, Accounting & BA Expense													
<u>Ancillary and Other</u>													
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
Basin Creek Variable Costs	$ 42.51	$ 43.86	$ 44.88	$ 44.82	$ 44.78	$ 44.48	$ 38.50	$ 37.93	$ 37.92	$ 42.33	$ 42.76	$ 42.31	$ 43.21
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
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
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
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
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
Total Delivered Supply	$ 29.20	$ 30.72	$ 32.82	$ 31.35	$ 31.28	$ 30.03	$ 27.43	$ 27.97	$ 27.14	$ 32.34	$ 31.76	$ 29.88	$ 30.28

NorthWestern Energy
Electric Utility
Total Estimated Electric Supply Rate
PPLM Hydro Assets Purchase
July 1, 2014

		Estimated	Colstrip Unit 4		Dave Gates Gen Station		Spion Kop		PPL Hydro Assets	
		Electric	Current	Current	Current	Current	Current	Current	Estimated	Estimated
		Supply	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Total Supply
		Rates [1]	Rates [2]	Rates [3]	Rates [4]	Rates [5]	Rates [6]	Rates [7]	Rates [8]	Rates
15	**Residential**									
16	Residential	0.037069	0.012734	0.004374	0.004795	0.002018	0.001458	0.000003	-	0.062451
17	Residential Employee	0.022240	0.007640	0.002625	0.002877	0.001212	0.000875	0.000002	-	0.037471
18	Total Residential									
20	**General Service 1**									
21	GS-1 Sec Non-Demand	0.033535	0.012734	0.004374	0.004795	0.002018	0.001459	0.000003	-	0.058918
22	GS-1 Sec Demand	0.037069	0.012734	0.004374	0.004795	0.002018	0.001459	0.000003	-	0.062452
23	GS-1 Pri Non-Demand	0.036051	0.012385	0.004254	0.004664	0.001963	0.001420	0.000003	-	0.060740
24	GS-1 Pri Demand	0.032920	0.012385	0.004254	0.004664	0.001963	0.001420	0.000003	-	0.057609
25	Total GS-1									
27	**General Service 2**									
28	GS-2 Substation	0.035742	0.012278	0.004218	0.004624	0.001946	0.001407	0.000003	-	0.060218
29	GS-2 Transmission	0.035528	0.012204	0.004192	0.004596	0.001934	0.001399	0.000003	-	0.059856
30	Total GS-2									
32	**Irrigation**									
33	Irrigation	0.033535	0.012734	0.004374	0.004795	0.002018	0.001459	0.000003	-	0.058918
34	Total Irrigation									
36	**Lighting**									
37	Lighting	0.033535	0.012734	0.004374	0.004795	0.002018	0.001459	0.000003	-	0.058918
38	Total Lighting									
40	**Average Billed Rate**	**0.036470**	**0.012681**	**0.004356**	**0.004775**	**0.002010**	**0.001453**	**0.000003**	**-**	**0.061748**
42	**Total Supply Rate**	**36.470**		**17.037**		**6.785**		**1.456**	**-**	**61.748**

[1] Source: Page 3 Attached and Annual Electric Supply Tracker Filing Docket No. D2014.5.46
[2] Source: Fixed rates approved in Docket No. D2010.5.50 Order No. 7093c, effective 04/01/2010.
[3] Source: Annual Electric Supply Tracker Filing Docket No. D2014.5.46
[4] Source: Fixed rates (based on 2nd yr rev req) approved in Docket No. D2008.8.95 Order No.6943e, effective 01/01/2012.
[5] Source: Annual Electric Supply Tracker Filing Docket No. D2014.5.46
[6] Source: Fixed rates (based on 2nd yr rev req) approved in Docket No. D2011.5.41 Order No.7159i, effective 1/1/2014.
[7] Source: Annual Electric Supply Tracker Filing Docket No. D2014.5.46

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1															
2															
3															
4															
5		**Northwestern Energy**													
6		**Electric Utility Derivation of Rates**													
7		**Electricity Supply Excluding Generation Assets - Prior to Cap Adjustment**													
8		**Tracker Period July 2014 - June 15**													
9															
10															
11						**Jul14 to Jun15**		**Sales Adjusted**				**Electricity**		**Electricity**	
12				**Loss**		**Supply Retail**		**for Employee**		**Sales Weighted**		**Supply Rate**		**Supply Revenue**	
13				**Factor**		**kWh Sales**		**Discount**		**by Losses**		**After Losses**		**Check**	
14		**Customer Rate Class**													
15		Residential		8.5100%		2,382,946,204		2,382,946,204		2,585,734,926		$ 0.036623		$ 87,270,639	
16		Residential Employee		8.5100%		3,488,614		2,093,168		2,271,297		$ 0.021974		$ 76,659	
17		GS 1 Secondary NonDemand		8.5100%		281,285,585		281,285,585		305,222,988		$ 0.036623		$ 10,301,522	
18		GS 1 Secondary Demand		8.5100%		2,447,309,441		2,447,309,441		2,655,575,475		$ 0.036623		$ 89,627,814	
19		GS 1 Primary NonDemand		5.5400%		558,086		558,086		589,004		$ 0.035621		$ 19,880	
20		GS 1 Primary Demand		5.5400%		359,164,093		359,164,093		379,061,784		$ 0.035621		$ 12,793,784	
21		General Service Substation		4.6300%		232,644,116		232,644,116		243,415,538		$ 0.035314		$ 8,215,594	
22		General Service Transmission		4.0000%		132,058,402		132,058,402		137,340,738		$ 0.035101		$ 4,635,382	
23		Irrigation		8.5100%		93,661,183		93,661,183		101,631,750		$ 0.036623		$ 3,430,154	
24		Lighting		8.5100%		59,884,934		59,884,934		64,981,141		$ 0.036623		$ 2,193,166	
25						5,993,000,659		5,991,605,213		6,475,824,643		$ 0.036478		$ 218,564,593	
26		YNP Contract				18,731,652						Rounding Adjustment		$ 3,668	
27		Total Electricity Supply Load				6,011,732,311								$ 218,568,260	
28															
29															
30								Electricity Supply Excluding Generation Assets Costs (Ref Line 48)		$ 219,772,706					
31								less: YNP Contract Revenues		$ (1,204,445)					
32								**Electricity Supply Excluding Generation Assets Rate Design Revenues**		**$ 218,568,260**					
33															
34								Electricity Supply Cost Rate Before Losses		$ 0.033751					
35								Electricity Supply Cost Rate After Losses		$ 0.036470					
36															
37		YNP Contract Load				18,731,652									
38		YNP May14-Apr15 Contract Supply Rate				0.064300									
39		YNP Supply Revenue				$ 1,204,445									
40															
41															
42		**Electric Supply Costs for period July 2014 through June 2015**													
43		Net Market Purchase Costs								$ 197,607,711					
44		DSM Lost Revenues	1							$ 7,564,633					
45		DSM Program Costs	1							$ 8,835,366					
46		Wind Other Costs	1							$ 1,810,052					
47		Carrying Costs	1							$ 1,422,086					
48		Adm & General	1							$ 1,930,703					
49		Transmission	1							$ 602,155					
50		**Total Supply Tracker Costs Excluding Generation Cost of Service**								$ 219,772,706					
51															
52															
53		[1]Based on Annual Electric Monthly Supply Tracker Filing D2014.5.46													

NorthWestern Energy
Electric Utility Derivation of Rates
Electricity Supply Excluding Generation Assets Capped at Residential Increase
Revenues ($000)
Tracker Period July 2014 - June 15

	B	D	F	H	J	L	N	P	R	T	V
11		Jul14 to Jun15									
12		Supply Retail	Current	Proposed	Proposed			$ at Res Cap	Capped	Capped	Capped
13	CAPPED RATES	kWh Sales	Revenue	Rates	Revenue	$ Change	% Change	-2.42%	$ Change	% Change	kWh Rates
14	**Residential**										
15	Residential	2,382,946	$ 89,434	$ 0.036623	$ 87,271	$ (2,164)	-2.42%	$ 87,271	$ 88,334	-1.23%	$ 0.037069
16	Res Employee	3,489	$ 79	$ 0.021974	$ 77	$ (2)	-2.42%	$ 77	$ 78	-1.23%	$ 0.022240
17	Total Residential	2,386,435	$ 89,513		$ 87,347	$ (2,166)	-2.42%	$ 87,347	$ 88,412	-1.23%	
18	**General Service 1**										
19	GS1 Sec NonDmd	281,286	$ 9,550	$ 0.036623	$ 10,302	$ 751	7.86%	$ 9,319	$ 9,433	-1.23%	$ 0.033535
20	GS1 Sec Dmd	2,447,309	$ 91,850	$ 0.036623	$ 89,628	$ (2,222)	-2.42%	$ 89,628	$ 90,720	-1.23%	$ 0.037069
21	GS1 Prim NonDmd	558	$ 20	$ 0.035621	$ 20	$ (0)	-2.41%	$ 20	$ 20	-1.23%	$ 0.036051
22	GS1 Prim Dmd	359,164	$ 11,971	$ 0.035621	$ 12,794	$ 823	6.87%	$ 11,681	$ 11,824	-1.23%	$ 0.032920
23	Total GS-1	3,088,317	$ 113,392		$ 112,743	$ (649)	-0.57%	$ 110,648	$ 111,997	-1.23%	
24	**General Service 2**										
25	GS2 Substation	232,644	$ 8,419	$ 0.035314	$ 8,216	$ (203)	-2.41%	$ 8,215	$ 8,315	-1.23%	$ 0.035742
26	GS2 Transmission	132,058	$ 4,750	$ 0.035101	$ 4,635	$ (115)	-2.42%	$ 4,635	$ 4,692	-1.23%	$ 0.035528
27	Total GS-2	364,703	$ 13,169		$ 12,851	$ (318)	-2.41%	$ 12,850	$ 13,007	-1.23%	
28	**Irrigation**										
29	Irrigation	93,661	$ 3,180	$ 0.036623	$ 3,430	$ 250	7.86%	$ 3,103	$ 3,141	-1.23%	$ 0.033535
30	Total Irrigation	93,661	$ 3,180		$ 3,430	$ 250	7.86%	$ 3,103	$ 3,141	-1.23%	
31	**Lighting**										
32	Lighting	59,885	$ 2,033	$ 0.036623	$ 2,193	$ 160	7.86%	$ 1,984	$ 2,008	-1.23%	$ 0.033535
33	Total Lighting	59,885	$ 2,033		$ 2,193	$ 160	7.86%	$ 1,984	$ 2,008	-1.23%	
34											
35	Total Rate Schedule	5,993,001	$ 221,287		$ 218,565	$ (2,722)	-1.23%	$ 215,933	$ 218,565		
36		-							-		
37	Capped Rate Adjustment Factor							0.012186			
38											

Electric Supply Cost Tracker
Electric Tracker Projection

Volumes in MWh	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Total
	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
Off System Transactions													
Fixed Price													
Base Fixed Price Purchases													
Competitive Solicitations	113,800	113,800	110,000	114,600	109,325	113,800	39,400	36,000	39,375	38,800	38,600	38,800	906,300
Base Fixed Price Sales													
Competitive Solicitations	-	-	-	-	-	-	-	-	-	-	-	-	-
Term Fixed Price Purchases	31,200	31,200	30,000	32,400	28,800	31,200	66,200	60,000	66,125	64,400	65,800	64,400	571,725
Term Fixed Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Index Price													
Base Index Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Base Index Price Sales													
Competitive Solicitations	(29,000)	(29,000)	(28,000)	(29,400)	(27,625)	(29,000)	(29,000)	(26,400)	(28,975)	(28,400)	(28,600)	(28,400)	(341,800)
Term Index Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Term Index Price Sales	(74,400)	(74,400)	(72,000)	(74,400)	(72,100)	(74,400)	-	-	-	-	-	-	(441,700)
Spot Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Sales	(41,600)	(41,600)	(40,000)	(43,200)	(38,400)	(41,600)	(76,600)	(69,600)	(76,525)	(74,800)	(75,800)	(74,800)	(694,525)
On System Transactions													
Fixed Price													
Rate Based Assets													
Colstrip Unit 4	150,288	150,288	145,440	150,288	145,440	150,288	150,288	135,744	150,086	145,440	150,288	145,440	1,769,318
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
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
Base Fixed Price Purchases													
Judith Gap	22,786	25,190	27,631	42,916	48,042	55,493	59,351	43,179	42,828	40,523	35,181	28,766	471,885
Other Small PPAs	12,403	10,802	6,744	5,490	3,605	3,720	3,720	3,360	3,715	3,600	8,355	11,967	77,482
Competitive Solicitations	20,800	20,800	20,000	21,600	19,200	20,800	20,800	19,200	20,800	20,800	20,000	20,800	245,600
QF Tier II	59,154	60,334	67,568	70,792	72,882	76,390	72,237	65,514	75,487	74,522	75,031	57,153	827,066
QF Tier II Adjustments													
QF-1 Tariff	10,373	11,160	11,475	14,225	16,214	16,740	18,228	13,776	14,489	12,709	13,671	10,801	163,860
Term Fixed Price Purchases	1,950	1,950	1,875	2,025	1,800	1,950	-	-	-	-	-	-	11,550
Term Fixed Price Sales	(1,950)	(1,950)	(1,875)	(2,025)	(1,800)	(1,950)	-	-	-	-	-	-	(11,550)
Index Price													
Base Index Price Purchases													
Basin Creek	6,525	13,271	9,153	4,768	5,879	10,691	4,727	3,265	4,050	1,258	835	1,132	65,555
Competitive Solicitations	45,400	45,400	44,000	45,000	44,475	45,400	29,000	26,400	28,975	28,400	28,600	28,400	439,450
Term Index Price Purchases	193,200	172,400	116,000	123,600	112,850	120,400	37,200	33,600	37,150	36,000	37,200	36,000	1,055,600
Term Index Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Purchases	64,019	52,500	32,954	42,824	50,790	101,525	201,598	198,584	162,043	119,734	120,573	158,952	1,306,095
Spot Sales	(5,242)	(5,887)	(5,628)	(27,931)	(1,940)	(2,948)	(13,027)	(19,923)	(21,287)	(9,524)	(4,961)	(3,020)	(121,318)
Imbalance, Current Month Estim	-	-	-	-	-	-	-	-	-	-	-	-	-

Imbalance, Prior Month True-up	-	-	-	-	-	-	-	-	-	-	-	-	-
Imbalance, Accounting & BA Exp	-	-	-	-	-	-	-	-	-	-	-	-	-
Ancillary and Other													
Basin Creek Fixed Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
Basin Creek Variable Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Other Cost													
DSM Program & Labor Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM Lost T& D Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM Lost Revenue Adjustment													
Total Delivered Supply	593,098	569,649	489,736	512,917	536,877	615,611	607,186	538,154	535,432	490,023	498,908	510,071	6,497,665

Electric Tracker Projection Excluding Generation Assets Cost of Service
Total Supply Expense

	Jul-14 Estimate	Aug-14 Estimate	Sep-14 Estimate	Oct-14 Estimate	Nov-14 Estimate	Dec-14 Estimate	Jan-15 Estimate	Feb-15 Estimate	Mar-15 Estimate	Apr-15 Estimate	May-15 Estimate	Jun-15 Estimate	Total
Off System Transactions													
Fixed Price													
Base Fixed Price Purchases													
Competitive Solicitations	$ 5,004,440	$ 5,004,440	$ 4,833,100	$ 5,065,860	$ 4,776,260	$ 5,004,440	$ 2,314,000	$ 2,112,960	$ 2,312,440	$ 2,276,560	$ 2,269,640	$ 2,276,560	$ 43,250,700
Base Fixed Price Sales													
Competitive Solicitations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Term Fixed Price Purchases	$ 1,279,200	$ 1,279,200	$ 1,230,000	$ 1,311,660	$ 1,165,920	$ 1,263,080	$ 2,390,810	$ 2,173,800	$ 2,388,569	$ 2,337,020	$ 2,362,990	$ 2,337,020	$ 21,519,269
Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Index Price													
Base Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Base Index Price Sales													
Competitive Solicitations	$ (1,069,846)	$ (1,353,924)	$ (1,201,160)	$ (1,168,464)	$ (1,165,520)	$ (1,419,174)	$ (1,222,602)	$ (1,062,360)	$ (1,164,461)	$ (744,000)	$ (674,668)	$ (682,328)	$ (12,928,507)
Term Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Term Index Price Sales	$ (2,466,872)	$ (3,257,904)	$ (2,934,640)	$ (2,881,056)	$ (2,959,039)	$ (3,544,696)	$ -	$ -	$ -	$ -	$ -	$ -	$ (18,044,207)
Spot Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Spot Sales	$ (1,812,512)	$ (2,157,792)	$ (1,870,000)	$ (1,792,800)	$ (1,703,040)	$ (2,132,000)	$ (3,355,846)	$ (2,906,496)	$ (3,195,684)	$ (2,246,992)	$ (2,088,290)	$ (2,060,740)	$ (27,322,192)
On System Transactions													
Fixed Price													
Rate Based Assets													
Colstrip Unit 4													$ -
Dave Gates Generating Station													$ -
Spion Kop													$ -
Base Fixed Price Purchases													
Judith Gap	$ 723,447	$ 799,775	$ 877,289	$ 1,362,569	$ 1,525,322	$ 1,761,904	$ 1,884,400	$ 1,370,923	$ 1,359,803	$ 1,286,618	$ 1,116,985	$ 913,326	$ 14,982,361
Other Small PPAs	$ 717,248	$ 611,561	$ 347,006	$ 260,993	$ 139,694	$ 144,150	$ 144,150	$ 130,200	$ 143,956	$ 139,500	$ 458,139	$ 706,397	$ 3,942,993
Competitive Solicitations	$ 1,123,720	$ 1,123,720	$ 1,080,500	$ 1,166,940	$ 1,037,280	$ 1,123,720	$ 1,123,720	$ 1,037,280	$ 1,123,720	$ 1,123,720	$ 1,080,500	$ 1,123,720	$ 13,268,540

QF Tier II	$ 2,252,585	$ 2,297,528	$ 2,572,982	$ 2,695,776	$ 2,775,365	$ 2,908,947	$ 2,750,791	$ 2,494,761	$ 2,874,549	$ 2,837,803	$ 2,857,191	$ 2,176,390	$ 31,494,669
QF Tier II Adjustments													
QF-1 Tariff	$ 717,070	$ 764,017	$ 778,671	$ 961,133	$ 1,092,522	$ 1,119,069	$ 1,217,139	$ 917,327	$ 971,985	$ 864,631	$ 931,767	$ 740,433	$ 11,075,766
Term Fixed Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Index Price													
Base Index Price Purchases													
Basin Creek	na	na	na	na	na	na	na	na	na	na	na	na	na
Competitive Solicitations	$ 1,298,326	$ 1,805,280	$ 1,637,480	$ 1,616,892	$ 1,694,282	$ 2,026,822	$ 1,201,802	$ 1,043,160	$ 1,143,661	$ 723,200	$ 654,668	$ 661,528	$ 15,507,101
Term Index Price Purchases	$ 7,775,876	$ 8,405,496	$ 4,979,320	$ 4,785,768	$ 4,661,505	$ 5,800,068	$ 1,434,956	$ 1,234,128	$ 1,361,490	$ 768,368	$ 698,136	$ 696,816	$ 42,601,926
Term Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Spot Purchases	$ 2,789,323	$ 2,723,155	$ 1,540,584	$ 1,777,205	$ 2,252,530	$ 5,203,165	$ 8,831,991	$ 8,292,862	$ 6,766,908	$ 3,596,819	$ 3,321,794	$ 4,379,121	$ 51,475,456
Spot Sales	$ (104,578)	$ (197,450)	$ (187,244)	$ (974,233)	$ (72,304)	$ (126,970)	$ (494,635)	$ (721,013)	$ (770,377)	$ (149,336)	$ (71,339)	$ (43,428)	$ (3,912,907)
Imbalance, Current Month Estim	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Imbalance, Prior Month True-up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Imbalance, Accounting & BA Exp	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
<u>Ancillary and Other</u>													
Basin Creek Fixed Costs	$ 355,755	$ 356,089	$ 361,576	$ 356,738	$ 792,573	$ 361,465	$ 375,308	$ 365,231	$ 353,305	$ 356,450	$ 777,549	$ 354,039	$ 5,166,077
Basin Creek Variable Costs	$ 276,188	$ 567,472	$ 387,307	$ 202,685	$ 257,848	$ 479,817	$ 211,893	$ 146,196	$ 180,150	$ 48,448	$ 31,675	$ 42,907	$ 2,832,586
Operating Reserves	$ 229,152	$ 229,152	$ 221,760	$ 229,152	$ 221,760	$ 229,152	$ 229,152	$ 206,976	$ 229,152	$ 221,760	$ 229,152	$ 221,760	$ 2,698,080
Wind Other Cost													
DSM Program & Labor Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM Lost T& D Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM Lost Revenue Adjustment													
Total Delivered Supply	$ 19,088,523	$ 18,999,815	$ 14,654,530	$ 14,976,818	$ 16,492,958	$ 20,202,958	$ 19,037,030	$ 16,835,935	$ 16,079,166	$ 13,440,569	$ 13,955,888	$ 13,843,521	$ 197,607,711

Electric Tracker Projection Excluding Generation Assets Cost of Service
Unit Costs

	Jul-14	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Total**
	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
<u>Off System Transactions</u>													
Fixed Price													
Base Fixed Price Purchases													
Competitive Solicitations	$ 43.98	$ 43.98	$ 43.94	$ 44.20	$ 43.69	$ 43.98	$ 58.73	$ 58.69	$ 58.73	$ 58.67	$ 58.80	$ 58.67	$ 47.72
Base Fixed Price Sales													
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
Term Fixed Price Purchases	$ 41.00	$ 41.00	$ 41.00	$ 40.48	$ 40.48	$ 40.48	$ 36.11	$ 36.23	$ 36.12	$ 36.29	$ 35.91	$ 36.29	$ 37.64
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
Index Price													
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
Base Index Price Sales													
Competitive Solicitations	$ 36.89	$ 46.69	$ 42.90	$ 39.74	$ 42.19	$ 48.94	$ 42.16	$ 40.24	$ 40.19	$ 26.20	$ 23.59	$ 24.03	$ 37.82
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

Term Index Price Sales	$ 33.16	$ 43.79	$ 40.76	$ 38.72	$ 41.04	$ 47.64	n/a	n/a	n/a	n/a	n/a	n/a	$ 40.85
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
Spot Sales	$ 43.57	$ 51.87	$ 46.75	$ 41.50	$ 44.35	$ 51.25	$ 43.81	$ 41.76	$ 41.76	$ 30.04	$ 27.55	$ 27.55	$ 39.34
<u>On System Transactions</u>													
Fixed Price													
Rate Based Assets													
Colstrip Unit 4													$ -
Dave Gates Generating Station													$ -
Spion Kop													$ -
Base Fixed Price Purchases													
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
Other Small PPAs	$ 57.83	$ 56.62	$ 51.45	$ 47.54	$ 38.75	$ 38.75	$ 38.75	$ 38.75	$ 38.75	$ 38.75	$ 54.84	$ 59.03	$ 50.89
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
QF Tier II	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08
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
QF-1 Tariff	$ 69.13	$ 68.46	$ 67.86	$ 67.57	$ 67.38	$ 66.85	$ 66.77	$ 66.59	$ 67.09	$ 68.03	$ 68.16	$ 68.55	$ 67.59
Spot Purchases	$ -	$ -	$ -	$ -	$ -	$ -	n/a	n/a	n/a	n/a	n/a	n/a	$ -
Spot Sales	$ -	$ -	$ -	$ -	$ -	$ -	n/a	n/a	n/a	n/a	n/a	n/a	$ -
Index Price													
Base Index Price Purchases													
Basin Creek	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
Competitive Solicitations	$ 28.60	$ 39.76	$ 37.22	$ 35.93	$ 38.10	$ 44.64	$ 41.44	$ 39.51	$ 39.47	$ 25.46	$ 22.89	$ 23.29	$ 35.29
Term Index Price Purchases	$ 40.25	$ 48.76	$ 42.93	$ 38.72	$ 41.31	$ 48.17	$ 38.57	$ 36.73	$ 36.65	$ 21.34	$ 18.77	$ 19.36	$ 40.36
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
Spot Purchases	$ 43.57	$ 51.87	$ 46.75	$ 41.50	$ 44.35	$ 51.25	$ 43.81	$ 41.76	$ 41.76	$ 30.04	$ 27.55	$ 27.55	$ 39.41
Spot Sales	$ 19.95	$ 33.54	$ 33.27	$ 34.88	$ 37.27	$ 43.07	$ 37.97	$ 36.19	$ 36.19	$ 15.68	$ 14.38	$ 14.38	$ 32.25
Imbalance, Current Month Estim	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
Imbalance, Prior Month 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
Imbalance, Accounting & BA Expense													
<u>Ancillary and Other</u>													
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
Basin Creek Variable Costs	$ 42.33	$ 42.76	$ 42.31	$ 42.51	$ 43.86	$ 44.88	$ 44.82	$ 44.78	$ 44.48	$ 38.50	$ 37.93	$ 37.92	$ 43.21
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
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
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
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
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
Total Delivered Supply	$ 32.18	$ 33.35	$ 29.92	$ 29.20	$ 30.72	$ 32.82	$ 31.35	$ 31.28	$ 30.03	$ 27.43	$ 27.97	$ 27.14	$ 30.41

NorthWestern Energy
Electric Utility
Total Estimated Electric Supply Rate
PPLM Hydro Assets Purchase
January 1, 2015

	Estimated	Colstrip Unit 4		Dave Gates Gen Station		Spion Kop		PPL Hydro Assets	
	Electric	Current	Current	Current	Current	Current	Current	Estimated	Estimated
	Supply	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Total Supply
	Rates [1]	Rates [2]	Rates [3]	Rates [4]	Rates [5]	Rates [6]	Rates [7]	Rates [8]	Rates
Residential									
Residential	0.036870	0.012734	0.004374	0.004795	0.002018	0.001458	0.000003	-	0.062252
Residential Employee	0.022121	0.007640	0.002625	0.002877	0.001212	0.000875	0.000002	-	0.037352
Total Residential									
General Service 1									
GS-1 Sec Non-Demand	0.033355	0.012734	0.004374	0.004795	0.002018	0.001459	0.000003	-	0.058738
GS-1 Sec Demand	0.036870	0.012734	0.004374	0.004795	0.002018	0.001459	0.000003	-	0.062253
GS-1 Pri Non-Demand	0.035857	0.012385	0.004254	0.004664	0.001963	0.001420	0.000003	-	0.060546
GS-1 Pri Demand	0.032743	0.012385	0.004254	0.004664	0.001963	0.001420	0.000003	-	0.057432
Total GS-1									
General Service 2									
GS-2 Substation	0.035549	0.012278	0.004218	0.004624	0.001946	0.001407	0.000003	-	0.060025
GS-2 Transmission	0.035337	0.012204	0.004192	0.004596	0.001934	0.001399	0.000003	-	0.059665
Total GS-2									
Irrigation									
Irrigation	0.033355	0.012734	0.004374	0.004795	0.002018	0.001459	0.000003	-	0.058738
Total Irrigation									
Lighting									
Lighting	0.033355	0.012734	0.004374	0.004795	0.002018	0.001459	0.000003	-	0.058738
Total Lighting									
Average Billed Rate	**0.036274**	**0.012681**	**0.004356**	**0.004775**	**0.002010**	**0.001453**	**0.000003**	**-**	**0.061552**
Total Supply Rate	**36.274**		**17.037**		**6.785**		**1.456**	**-**	**61.552**

[1] Source: Page 10 Attached and Annual Electric Supply Tracker Filing Docket No. D2014.5.46
[2] Source: Fixed rates approved in Docket No. D2010.5.50 Order No. 7093c, effective 04/01/2010.
[3] Source: Annual Electric Supply Tracker Filing Docket No. D2014.5.46
[4] Source: Fixed rates (based on 2nd yr rev req) approved in Docket No. D2008.8.95 Order No.6943e, effective 01/01/2012.
[5] Source: Annual Electric Supply Tracker Filing Docket No. D2014.5.46
[6] Source: Fixed rates (based on 2nd yr rev req) approved in Docket No. D2011.5.41 Order No.7159i, effective 1/1/2014.
[7] Source: Annual Electric Supply Tracker Filing Docket No. D2014.5.46

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1															
2															
3															
4															
5		**Northwestern Energy**													
6		**Electric Utility Derivation of Rates**													
7		**Electricity Supply Excluding Generation Assets - Prior to Cap Adjustment**													
8		**Tracker Period Jan. 2015 - Dec. 15**													
9															
10															
11						**Jul14 to Jun15**		**Sales Adjusted**				**Electricity**		**Electricity**	
12				**Loss**		**Supply Retail**		**for Employee**		**Sales Weighted**		**Supply Rate**		**Supply Revenue**	
13				**Factor**		**kWh Sales**		**Discount**		**by Losses**		**After Losses**		**Check**	
14		**Customer Rate Class**													
15		Residential		8.5100%		2,382,946,204		2,382,946,204		2,585,734,926		$ 0.036426		$ 86,801,198	
16		Residential Employee		8.5100%		3,488,614		2,093,168		2,271,297		$ 0.021856		$ 76,247	
17		GS 1 Secondary NonDemand		8.5100%		281,285,585		281,285,585		305,222,988		$ 0.036426		$ 10,246,109	
18		GS 1 Secondary Demand		8.5100%		2,447,309,441		2,447,309,441		2,655,575,475		$ 0.036426		$ 89,145,694	
19		GS 1 Primary NonDemand		5.5400%		558,086		558,086		589,004		$ 0.035429		$ 19,772	
20		GS 1 Primary Demand		5.5400%		359,164,093		359,164,093		379,061,784		$ 0.035429		$ 12,724,825	
21		General Service Substation		4.6300%		232,644,116		232,644,116		243,415,538		$ 0.035123		$ 8,171,159	
22		General Service Transmission		4.0000%		132,058,402		132,058,402		137,340,738		$ 0.034912		$ 4,610,423	
23		Irrigation		8.5100%		93,661,183		93,661,183		101,631,750		$ 0.036426		$ 3,411,702	
24		Lighting		8.5100%		59,884,934		59,884,934		64,981,141		$ 0.036426		$ 2,181,369	
25						5,993,000,659		5,991,605,213		6,475,824,643		$ 0.036282		$ 217,388,498	
26		YNP Contract				18,731,652						Rounding Adjustment		$ 1,481	
27		Total Electricity Supply Load				6,011,732,311								$ 217,389,979	
28															
29															
30		Electricity Supply Excluding Generation Assets Costs (Ref Line 48)								$ 218,594,424					
31		less: YNP Contract Revenues								$ (1,204,445)					
32		**Electricity Supply Excluding Generation Assets Rate Design Revenues**								**$ 217,389,979**					
33															
34		Electricity Supply Cost Rate Before Losses								$ 0.033569					
35		Electricity Supply Cost Rate After Losses								$ 0.036274					
36															
37		YNP Contract Load				18,731,652									
38		YNP May14-Apr15 Contract Supply Rate				0.064300									
39		YNP Supply Revenue				$ 1,204,445									
40															
41															
42		**Electric Supply Costs for period July 2014 through June 2015**													
43		Net Market Purchase Costs								$ 196,429,429					
44		DSM Lost Revenues	1							$ 7,564,633					
45		DSM Program Costs	1							$ 8,835,366					
46		Wind Other Costs	1							$ 1,810,052					
47		Carrying Costs	1							$ 1,422,086					
48		Adm & General	1							$ 1,930,703					
49		Transmission	1							$ 602,155					
50		**Total Supply Tracker Costs Excluding Generation Cost of Service**								$ 218,594,424					
51															
52															
53		[1]Based on Annual Electric Monthly Supply Tracker Filing D2014.5.46													

	B	D	F	H	J	L	N	P	R	T	V
1											
2											
3											
4											
5	**NorthWestern Energy**										
6	**Electric Utility Derivation of Rates**										
7	**Electricity Supply Excluding Generation Assets Capped at Residential Increase**										
8	**Revenues ($000)**										
9	**Tracker Period Jan. 2015 - Dec. 15**										
10											
11		**Jul14 to Jun15**									
12		**Supply Retail**	**Current**	**Proposed**	**Proposed**			**$ at Res Cap**	**Capped**	**Capped**	**Capped**
13	**CAPPED RATES**	**kWh Sales**	**Revenue**	**Rates**	**Revenue**	**$ Change**	**% Change**	**-2.94%**	**$ Change**	**% Change**	**kWh Rates**
14	**Residential**										
15	Residential	2,382,946	$ 89,434	$ 0.036426	$ 86,801	$ (2,633)	-2.94%	$ 86,801	$ 87,859	-1.76%	$ 0.036870
16	Res Employee	3,489	$ 79	$ 0.021856	$ 76	$ (2)	-2.94%	$ 76	$ 77	-1.76%	$ 0.022121
17	Total Residential	2,386,435	$ 89,513		$ 86,877	$ (2,635)	-2.94%	$ 86,877	$ 87,936	-1.76%	
18	**General Service 1**										
19	GS1 Sec NonDmd	281,286	$ 9,550	$ 0.036426	$ 10,246	$ 696	7.28%	$ 9,269	$ 9,382	-1.76%	$ 0.033355
20	GS1 Sec Dmd	2,447,309	$ 91,850	$ 0.036426	$ 89,146	$ (2,704)	-2.94%	$ 89,146	$ 90,232	-1.76%	$ 0.036870
21	GS1 Prim NonDmd	558	$ 20	$ 0.035429	$ 20	$ (1)	-2.93%	$ 20	$ 20	-1.76%	$ 0.035857
22	GS1 Prim Dmd	359,164	$ 11,971	$ 0.035429	$ 12,725	$ 754	6.30%	$ 11,618	$ 11,760	-1.76%	$ 0.032743
23	Total GS-1	3,088,317	$ 113,392		$ 112,136	$ (1,255)	-1.11%	$ 110,053	$ 111,394	-1.76%	
24	**General Service 2**										
25	GS2 Substation	232,644	$ 8,419	$ 0.035123	$ 8,171	$ (248)	-2.94%	$ 8,171	$ 8,270	-1.76%	$ 0.035549
26	GS2 Transmission	132,058	$ 4,750	$ 0.034912	$ 4,610	$ (140)	-2.94%	$ 4,610	$ 4,667	-1.76%	$ 0.035337
27	Total GS-2	364,703	$ 13,169		$ 12,782	$ (387)	-2.94%	$ 12,781	$ 12,937	-1.76%	
28	**Irrigation**										
29	Irrigation	93,661	$ 3,180	$ 0.036426	$ 3,412	$ 232	7.28%	$ 3,086	$ 3,124	-1.76%	$ 0.033355
30	Total Irrigation	93,661	$ 3,180		$ 3,412	$ 232	7.28%	$ 3,086	$ 3,124	-1.76%	
31	**Lighting**										
32	Lighting	59,885	$ 2,033	$ 0.036426	$ 2,181	$ 148	7.28%	$ 1,973	$ 1,997	-1.76%	$ 0.033355
33	Total Lighting	59,885	$ 2,033		$ 2,181	$ 148	7.28%	$ 1,973	$ 1,997	-1.76%	
34											
35	Total Rate Schedule	5,993,001	$ 221,287		$ 217,388	$ (3,899)	-1.76%	$ 214,772	$ 217,388		
36		-							-		
37	Capped Rate Adjustment Factor							0.012184			
38											

Electric Supply Cost Tracker
Electric Tracker Projection

Volumes in MWh	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Total**
	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
Off System Transactions													
Fixed Price													
Base Fixed Price Purchases													
Competitive Solicitations	39,400	36,000	39,375	38,800	38,600	38,800	39,400	39,400	38,000	40,200	37,225	39,400	464,600
Base Fixed Price Sales													
Competitive Solicitations	-	-	-	-	-	-	-	-	-	-	-	-	-
Term Fixed Price Purchases	66,200	60,000	66,125	64,400	65,800	64,400	66,200	66,200	64,000	66,600	63,675	66,200	779,800
Term Fixed Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Index Price													
Base Index Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Base Index Price Sales													
Competitive Solicitations	(29,000)	(26,400)	(28,975)	(28,400)	(28,600)	(28,400)	(10,400)	(10,400)	(10,000)	(10,800)	(9,600)	(10,400)	(231,375)
Term Index Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Term Index Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Sales	(76,600)	(69,600)	(76,525)	(74,800)	(75,800)	(74,800)	(95,200)	(95,200)	(92,000)	(96,000)	(91,300)	(95,200)	(1,013,025)
On System Transactions													
Fixed Price													
Rate Based Assets													
Colstrip Unit 4	150,288	135,744	150,086	145,440	150,288	145,440	150,288	150,288	145,440	150,288	145,440	150,288	1,769,318
Dave Gates Generating Station	5,208	4,704	5,208	5,040	5,208	5,040	5,208	5,208	5,040	5,208	5,040	5,208	61,320
Spion Kop	17,856	10,752	11,888	11,520	8,928	8,640	8,184	8,184	9,360	14,136	14,400	11,904	135,752
Base Fixed Price Purchases													
Judith Gap	59,351	43,179	42,828	40,523	35,181	28,766	22,786	25,190	27,631	42,916	48,042	55,493	471,885
Other Small PPAs	3,720	3,360	3,715	3,600	8,355	11,967	12,403	10,802	6,744	5,490	3,605	3,720	77,482
Competitive Solicitations	20,800	19,200	20,800	20,800	20,000	20,800	20,800	20,800	20,000	21,600	19,200	20,800	245,600
QF Tier II	72,237	65,514	75,487	74,522	75,031	57,153	59,154	60,334	67,568	70,792	72,882	76,390	827,066
QF Tier II Adjustments													
QF-1 Tariff	18,228	13,776	14,489	12,709	13,671	10,801	10,373	11,160	11,475	14,225	16,204	16,740	163,850
Term Fixed Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Term Fixed Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Index Price													
Base Index Price Purchases													
Basin Creek	4,727	3,265	4,050	1,258	835	1,132	6,525	13,271	9,153	4,768	5,879	10,691	65,555
Competitive Solicitations	29,000	26,400	28,975	28,400	28,600	28,400	10,400	10,400	10,000	10,800	9,600	10,400	231,375
Term Index Price Purchases	37,200	33,600	37,150	36,000	37,200	36,000	37,200	37,200	36,000	37,200	36,050	37,200	438,000
Term Index Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Purchases	201,598	198,584	162,043	119,734	120,573	158,952	255,019	222,700	146,954	163,424	162,475	219,725	2,131,780
Spot Sales	(13,027)	(19,923)	(21,287)	(9,524)	(4,961)	(3,020)	(5,242)	(5,887)	(5,628)	(27,931)	(1,940)	(2,948)	(121,318)
Imbalance, Current Month Estim	-	-	-	-	-	-	-	-	-	-	-	-	-

Imbalance, Prior Month True-up	-	-	-	-	-	-	-	-	-	-	-	-	-
Imbalance, Accounting & BA Exp	-	-	-	-	-	-	-	-	-	-	-	-	-
Ancillary and Other													
Basin Creek Fixed Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
Basin Creek Variable Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Other Cost													
DSM Program & Labor Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM Lost T& D Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM Lost Revenue Adjustment													
Total Delivered Supply	607,186	538,154	535,432	490,023	498,908	510,071	593,098	569,649	489,736	512,917	536,877	615,611	6,497,665

Electric Tracker Projection Excluding Generation Assets Cost of Service
Total Supply Expense

	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
Off System Transactions													
Fixed Price													
Base Fixed Price Purchases													
Competitive Solicitations	$ 2,314,000	$ 2,112,960	$ 2,312,440	$ 2,276,560	$ 2,269,640	$ 2,276,560	$ 2,314,000	$ 2,314,000	$ 2,232,200	$ 2,358,360	$ 2,189,400	$ 2,314,000	$ 27,284,120
Base Fixed Price Sales													
Competitive Solicitations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Term Fixed Price Purchases	$ 2,390,810	$ 2,173,800	$ 2,388,569	$ 2,337,020	$ 2,362,990	$ 2,337,020	$ 2,390,810	$ 2,390,810	$ 2,309,200	$ 2,418,630	$ 2,283,621	$ 2,390,810	$ 28,174,090
Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Index Price													
Base Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Base Index Price Sales													
Competitive Solicitations	$ (1,222,602)	$ (1,062,360)	$ (1,164,461)	$ (744,000)	$ (674,668)	$ (682,328)	$ (450,736)	$ (449,176)	$ (431,400)	$ (457,056)	$ (407,232)	$ (442,728)	$ (8,188,747)
Term Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Term Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Spot Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Spot Sales	$ (3,355,846)	$ (2,906,496)	$ (3,195,684)	$ (2,246,992)	$ (2,088,290)	$ (2,060,740)	$ (4,125,968)	$ (4,111,688)	$ (3,968,880)	$ (4,062,720)	$ (3,872,946)	$ (4,052,664)	$ (40,048,914)
On System Transactions													
Fixed Price													
Rate Based Assets													
Colstrip Unit 4													$ -
Dave Gates Generating Station													$ -
Spion Kop													$ -
Base Fixed Price Purchases													
Judith Gap	$ 1,884,400	$ 1,370,923	$ 1,359,803	$ 1,286,618	$ 1,116,985	$ 913,326	$ 723,447	$ 799,775	$ 877,289	$ 1,362,569	$ 1,525,322	$ 1,761,904	$ 14,982,361
Other Small PPAs	$ 144,150	$ 130,200	$ 143,956	$ 139,500	$ 458,139	$ 706,397	$ 732,443	$ 623,955	$ 352,508	$ 264,091	$ 139,694	$ 144,150	$ 3,979,183
Competitive Solicitations	$ 1,123,720	$ 1,037,280	$ 1,123,720	$ 1,123,720	$ 1,080,500	$ 1,123,720	$ 1,123,720	$ 1,123,720	$ 1,080,500	$ 1,166,940	$ 1,037,280	$ 1,123,720	$ 13,268,540

QF Tier II	$ 2,750,791	$ 2,494,761	$ 2,874,549	$ 2,837,803	$ 2,857,191	$ 2,176,390	$ 2,295,176	$ 2,340,969	$ 2,621,630	$ 2,746,747	$ 2,827,840	$ 2,963,949	$ 31,787,797
QF Tier II Adjustments													
QF-1 Tariff	$ 1,217,139	$ 917,327	$ 971,985	$ 864,631	$ 931,767	$ 740,433	$ 718,097	$ 765,051	$ 779,664	$ 962,316	$ 1,093,194	$ 1,120,174	$ 11,081,779
Term Fixed Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Index Price													
Base Index Price Purchases													
Basin Creek	na	na	na	na	na	na	na	na	na	na	na	na	na
Competitive Solicitations	$ 1,201,802	$ 1,043,160	$ 1,143,661	$ 723,200	$ 654,668	$ 661,528	$ 429,936	$ 428,376	$ 411,400	$ 435,456	$ 388,032	$ 421,928	$ 7,943,147
Term Index Price Purchases	$ 1,434,956	$ 1,234,128	$ 1,361,490	$ 768,368	$ 698,136	$ 696,816	$ 1,264,624	$ 1,260,028	$ 1,215,600	$ 1,371,360	$ 1,317,960	$ 1,373,412	$ 13,996,878
Term Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Spot Purchases	$ 8,831,991	$ 8,292,862	$ 6,766,908	$ 3,596,819	$ 3,321,794	$ 4,379,121	$ 11,052,539	$ 9,618,396	$ 6,339,581	$ 6,916,113	$ 6,892,184	$ 9,353,700	$ 85,362,007
Spot Sales	$ (494,635)	$ (721,013)	$ (770,377)	$ (149,336)	$ (71,339)	$ (43,428)	$ (147,720)	$ (165,366)	$ (157,865)	$ (993,785)	$ (69,180)	$ (105,509)	$ (3,889,553)
Imbalance, Current Month Estim	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Imbalance, Prior Month True-up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Imbalance, Accounting & BA Exp	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
<u>Ancillary and Other</u>													
Basin Creek Fixed Costs	$ 375,308	$ 365,231	$ 353,305	$ 356,450	$ 777,549	$ 354,039	$ 355,755	$ 356,089	$ 361,576	$ 356,738	$ 792,573	$ 361,465	$ 5,166,077
Basin Creek Variable Costs	$ 211,893	$ 146,196	$ 180,150	$ 48,448	$ 31,675	$ 42,907	$ 276,188	$ 567,472	$ 387,307	$ 202,685	$ 257,848	$ 479,817	$ 2,832,586
Operating Reserves	$ 229,152	$ 206,976	$ 229,152	$ 221,760	$ 229,152	$ 221,760	$ 229,152	$ 229,152	$ 221,760	$ 229,152	$ 221,760	$ 229,152	$ 2,698,080
Wind Other Cost													
DSM Program & Labor Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM Lost T& D Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM Lost Revenue Adjustment													
Total Delivered Supply	$ 19,037,030	$ 16,835,935	$ 16,079,166	$ 13,440,569	$ 13,955,888	$ 13,843,521	$ 19,181,464	$ 18,091,563	$ 14,632,070	$ 15,277,596	$ 16,617,349	$ 19,437,279	$ 196,429,429

Electric Tracker Projection Excluding Generation Assets Cost of Service
Unit Costs

	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
<u>Off System Transactions</u>													
Fixed Price													
Base Fixed Price Purchases													
Competitive Solicitations	$ 58.73	$ 58.69	$ 58.73	$ 58.67	$ 58.80	$ 58.67	$ 58.73	$ 58.73	$ 58.74	$ 58.67	$ 58.82	$ 58.73	$ 58.73
Base Fixed Price Sales													
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
Term Fixed Price Purchases	$ 36.11	$ 36.23	$ 36.12	$ 36.29	$ 35.91	$ 36.29	$ 36.11	$ 36.11	$ 36.08	$ 36.32	$ 35.86	$ 36.11	$ 36.13
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
Index Price													
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
Base Index Price Sales													
Competitive Solicitations	$ 42.16	$ 40.24	$ 40.19	$ 26.20	$ 23.59	$ 24.03	$ 43.34	$ 43.19	$ 43.14	$ 42.32	$ 42.42	$ 42.57	$ 35.39
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

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
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
Spot Sales	$ 43.81	$ 41.76	$ 41.76	$ 30.04	$ 27.55	$ 27.55	$ 43.34	$ 43.19	$ 43.14	$ 42.32	$ 42.42	$ 42.57	$ 39.53
<u>On System Transactions</u>													
Fixed Price													
Rate Based Assets													
Colstrip Unit 4													$ -
Dave Gates Generating Station													$ -
Spion Kop													$ -
Base Fixed Price Purchases													
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
Other Small PPAs	$ 38.75	$ 38.75	$ 38.75	$ 38.75	$ 54.84	$ 59.03	$ 59.05	$ 57.76	$ 52.27	$ 48.10	$ 38.75	$ 38.75	$ 51.36
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
QF Tier II	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.08	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.43
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
QF-1 Tariff	$ 66.77	$ 66.59	$ 67.09	$ 68.03	$ 68.16	$ 68.55	$ 69.23	$ 68.55	$ 67.95	$ 67.65	$ 67.46	$ 66.92	$ 67.63
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
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
Index Price													
Base Index Price Purchases													
Basin Creek	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
Competitive Solicitations	$ 41.44	$ 39.51	$ 39.47	$ 25.46	$ 22.89	$ 23.29	$ 41.34	$ 41.19	$ 41.14	$ 40.32	$ 40.42	$ 40.57	$ 34.33
Term Index Price Purchases	$ 38.57	$ 36.73	$ 36.65	$ 21.34	$ 18.77	$ 19.36	$ 34.00	$ 33.87	$ 33.77	$ 36.86	$ 36.56	$ 36.92	$ 31.96
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
Spot Purchases	$ 43.81	$ 41.76	$ 41.76	$ 30.04	$ 27.55	$ 27.55	$ 43.34	$ 43.19	$ 43.14	$ 42.32	$ 42.42	$ 42.57	$ 40.04
Spot Sales	$ 37.97	$ 36.19	$ 36.19	$ 15.68	$ 14.38	$ 14.38	$ 28.18	$ 28.09	$ 28.05	$ 35.58	$ 35.66	$ 35.79	$ 32.06
Imbalance, Current Month Estim	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
Imbalance, Prior Month 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
Imbalance, Accounting & BA Expense													
<u>Ancillary and Other</u>													
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
Basin Creek Variable Costs	$ 44.82	$ 44.78	$ 44.48	$ 38.50	$ 37.93	$ 37.92	$ 42.33	$ 42.76	$ 42.31	$ 42.51	$ 43.86	$ 44.88	$ 43.21
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
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
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
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
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
Total Delivered Supply	$ 31.35	$ 31.28	$ 30.03	$ 27.43	$ 27.97	$ 27.14	$ 32.34	$ 31.76	$ 29.88	$ 29.79	$ 30.95	$ 31.57	$ 30.23

	B	D	F	H	J	L	N	P	R	T
1										
2										
3										
4										
5	**NorthWestern Energy**									
6	**Electric Utility**									
7	**Total Estimated Electric Supply Rate**									
8	**PPLM Hydro Assets Purchase**									
9	**July 1, 2015**									
10										
11		**Estimated**	**Colstrip Unit 4**		**Dave Gates Gen Station**		**Spion Kop**		**PPL Hydro Assets**	
12		**Electric**	**Current**	**Current**	**Current**	**Current**	**Current**	**Current**	**Estimated**	**Estimated**
13		**Supply**	**Fixed**	**Variable**	**Fixed**	**Variable**	**Fixed**	**Variable**	**Fixed**	**Total Supply**
14		**Rates [1]**	**Rates [2]**	**Rates [3]**	**Rates [4]**	**Rates [5]**	**Rates [6]**	**Rates [7]**	**Rates [8]**	**Rates**
15	**Residential**									
16	Residential	0.037854	0.012734	0.004374	0.004795	0.002018	0.001458	0.000003	-	0.063236
17	Residential Employee	0.022711	0.007640	0.002625	0.002877	0.001212	0.000875	0.000002	-	0.037942
18	Total Residential									
19										
20	**General Service 1**									
21	GS-1 Sec Non-Demand	0.034245	0.012734	0.004374	0.004795	0.002018	0.001459	0.000003	-	0.059628
22	GS-1 Sec Demand	0.037854	0.012734	0.004374	0.004795	0.002018	0.001459	0.000003	-	0.063237
23	GS-1 Pri Non-Demand	0.036814	0.012385	0.004254	0.004664	0.001963	0.001420	0.000003	-	0.061503
24	GS-1 Pri Demand	0.033617	0.012385	0.004254	0.004664	0.001963	0.001420	0.000003	-	0.058306
25	Total GS-1									
26										
27	**General Service 2**									
28	GS-2 Substation	0.036498	0.012278	0.004218	0.004624	0.001946	0.001407	0.000003	-	0.060974
29	GS-2 Transmission	0.036280	0.012204	0.004192	0.004596	0.001934	0.001399	0.000003	-	0.060608
30	Total GS-2									
31										
32	**Irrigation**									
33	Irrigation	0.034245	0.012734	0.004374	0.004795	0.002018	0.001459	0.000003	-	0.059628
34	Total Irrigation									
35										
36	**Lighting**									
37	Lighting	0.034245	0.012734	0.004374	0.004795	0.002018	0.001459	0.000003	-	0.059628
38	Total Lighting									
39										
40	**Average Billed Rate**	**0.037242**	**0.012681**	**0.004356**	**0.004775**	**0.002010**	**0.001453**	**0.000003**	**-**	**0.062520**
41										
42	**Total Supply Rate**	**37.242**		**17.037**		**6.785**		**1.456**	**-**	**62.520**
43										
44	[1] Source: Page 17 Attached and Annual Electric Supply Tracker Filing Docket No. D2014.5.46									
45	[2] Source: Fixed rates approved in Docket No. D2010.5.50 Order No. 7093c, effective 04/01/2010.									
46	[3] Source: Annual Electric Supply Tracker Filing Docket No. D2014.5.46									
47	[4] Source: Fixed rates (based on 2nd yr rev req) approved in Docket No. D2008.8.95 Order No.6943e, effective 01/01/2012.									
48	[5] Source: Annual Electric Supply Tracker Filing Docket No. D2014.5.46									
49	[6] Source: Fixed rates (based on 2nd yr rev req) approved in Docket No. D2011.5.41 Order No.7159i, effective 1/1/2014.									
50	[7] Source: Annual Electric Supply Tracker Filing Docket No. D2014.5.46									
51										

Northwestern Energy
Electric Utility Derivation of Rates
Electricity Supply Excluding Generation Assets - Prior to Cap Adjustment
Tracker Period July 2015 - June 16

Row	B	D	F	H	J	L	N
11			Jul14 to Jun15	Sales Adjusted		Electricity	Electricity
12		Loss	Supply Retail	for Employee	Sales Weighted	Supply Rate	Supply Revenue
13		Factor	kWh Sales	Discount	by Losses	After Losses	Check
14	**Customer Rate Class**						
15	Residential	8.5100%	2,382,946,204	2,382,946,204	2,585,734,926	$ 0.037398	$ 89,117,422
16	Residential Employee	8.5100%	3,488,614	2,093,168	2,271,297	$ 0.022439	$ 78,281
17	GS 1 Secondary NonDemand	8.5100%	281,285,585	281,285,585	305,222,988	$ 0.037398	$ 10,519,518
18	GS 1 Secondary Demand	8.5100%	2,447,309,441	2,447,309,441	2,655,575,475	$ 0.037398	$ 91,524,478
19	GS 1 Primary NonDemand	5.5400%	558,086	558,086	589,004	$ 0.036374	$ 20,300
20	GS 1 Primary Demand	5.5400%	359,164,093	359,164,093	379,061,784	$ 0.036374	$ 13,064,235
21	General Service Substation	4.6300%	232,644,116	232,644,116	243,415,538	$ 0.036061	$ 8,389,379
22	General Service Transmission	4.0000%	132,058,402	132,058,402	137,340,738	$ 0.035844	$ 4,733,501
23	Irrigation	8.5100%	93,661,183	93,661,183	101,631,750	$ 0.037398	$ 3,502,741
24	Lighting	8.5100%	59,884,934	59,884,934	64,981,141	$ 0.037398	$ 2,239,577
25			5,993,000,659	5,991,605,213	6,475,824,643	$ 0.037250	$ 223,189,433
26	YNP Contract		18,731,652			Rounding Adjustment	$ 311
27	Total Electricity Supply Load		6,011,732,311				$ 223,189,744
30	Electricity Supply Excluding Generation Assets Costs (Ref Line 48)				$ 224,394,189		
31	less: YNP Contract Revenues				$ (1,204,445)		
32	**Electricity Supply Excluding Generation Assets Rate Design Revenues**				**$ 223,189,744**		
34	Electricity Supply Cost Rate Before Losses				$ 0.034465		
35	Electricity Supply Cost Rate After Losses				$ 0.037242		
37	YNP Contract Load		18,731,652				
38	YNP May14-Apr15 Contract Supply Rate		0.064300				
39	YNP Supply Revenue		$ 1,204,445				
42	**Electric Supply Costs for period July 2014 through June 2015**						
43	Net Market Purchase Costs				$ 202,229,194		
44	DSM Lost Revenues [1]				$ 7,564,633		
45	DSM Program Costs [1]				$ 8,835,366		
46	Wind Other Costs [1]				$ 1,810,052		
47	Carrying Costs [1]				$ 1,422,086		
48	Adm & General [1]				$ 1,930,703		
49	Transmission [1]				$ 602,155		
50	**Total Supply Tracker Costs Excluding Generation Cost of Service**				$ 224,394,189		
53	[1]Based on Annual Electric Monthly Supply Tracker Filing D2014.5.46						

NorthWestern Energy
Electric Utility Derivation of Rates
Electricity Supply Excluding Generation Assets Capped at Residential Increase
Revenues ($000)
Tracker Period July 2015 - June 16

	B	D	F	H	J	L	N	P	R	T	V
11		Jul14 to Jun15									
12		Supply Retail	Current	Proposed	Proposed			$ at Res Cap	Capped	Capped	Capped
13	CAPPED RATES	kWh Sales	Revenue	Rates	Revenue	$ Change	% Change	-0.35%	$ Change	% Change	kWh Rates
14	**Residential**										
15	Residential	2,382,946	$ 89,434	$ 0.037398	$ 89,117	$ (317)	-0.35%	$ 89,117	$ 90,203	0.86%	$ 0.037854
16	Res Employee	3,489	$ 79	$ 0.022439	$ 78	$ (0)	-0.36%	$ 78	$ 79	0.86%	$ 0.022711
17	Total Residential	2,386,435	$ 89,513		$ 89,196	$ (317)	-0.35%	$ 89,196	$ 90,282	0.86%	
18	**General Service 1**										
19	GS1 Sec NonDmd	281,286	$ 9,550	$ 0.037398	$ 10,520	$ 969	10.15%	$ 9,517	$ 9,633	0.86%	$ 0.034245
20	GS1 Sec Dmd	2,447,309	$ 91,850	$ 0.037398	$ 91,524	$ (325)	-0.35%	$ 91,524	$ 92,640	0.86%	$ 0.037854
21	GS1 Prim NonDmd	558	$ 20	$ 0.036374	$ 20	$ (0)	-0.35%	$ 20	$ 21	0.86%	$ 0.036814
22	GS1 Prim Dmd	359,164	$ 11,971	$ 0.036374	$ 13,064	$ 1,093	9.13%	$ 11,929	$ 12,074	0.86%	$ 0.033617
23	Total GS-1	3,088,317	$ 113,392		$ 115,129	$ 1,737	1.53%	$ 112,990	$ 114,367	0.86%	
24	**General Service 2**										
25	GS2 Substation	232,644	$ 8,419	$ 0.036061	$ 8,389	$ (29)	-0.35%	$ 8,389	$ 8,491	0.86%	$ 0.036498
26	GS2 Transmission	132,058	$ 4,750	$ 0.035844	$ 4,734	$ (17)	-0.35%	$ 4,733	$ 4,791	0.86%	$ 0.036280
27	Total GS-2	364,703	$ 13,169		$ 13,123	$ (46)	-0.35%	$ 13,122	$ 13,282	0.86%	
28	**Irrigation**										
29	Irrigation	93,661	$ 3,180	$ 0.037398	$ 3,503	$ 323	10.15%	$ 3,169	$ 3,207	0.86%	$ 0.034245
30	Total Irrigation	93,661	$ 3,180		$ 3,503	$ 323	10.15%	$ 3,169	$ 3,207	0.86%	
31	**Lighting**										
32	Lighting	59,885	$ 2,033	$ 0.037398	$ 2,240	$ 206	10.15%	$ 2,026	$ 2,051	0.86%	$ 0.034245
33	Total Lighting	59,885	$ 2,033		$ 2,240	$ 206	10.15%	$ 2,026	$ 2,051	0.86%	
34											
35	Total Rate Schedule	5,993,001	$ 221,287		$ 223,189	$ 1,902	0.86%	$ 220,503	$ 223,189		
36		-							-		
37	Capped Rate Adjustment Factor							0.012184			
38											

Electric Supply Cost Tracker
Electric Tracker Projection

Volumes in MWh	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Total
	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
Off System Transactions													
Fixed Price													
Base Fixed Price Purchases													
Competitive Solicitations	39,400	39,400	38,000	40,200	37,225	39,400	38,600	37,400	40,175	38,800	38,600	38,800	466,000
Base Fixed Price Sales													
Competitive Solicitations	-	-	-	-	-	-	-	-	-	-	-	-	-
Term Fixed Price Purchases	66,200	66,200	64,000	66,600	63,675	66,200	47,200	44,800	47,950	46,400	47,200	46,400	672,825
Term Fixed Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Index Price													
Base Index Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Base Index Price Sales													
Competitive Solicitations	(10,400)	(10,400)	(10,000)	(10,800)	(9,600)	(10,400)	(10,000)	(10,000)	(10,800)	(10,400)	(10,000)	(10,400)	(123,200)
Term Index Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Term Index Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Sales	(95,200)	(95,200)	(92,000)	(96,000)	(91,300)	(95,200)	(75,800)	(72,200)	(77,325)	(74,800)	(75,800)	(74,800)	(1,015,625)
On System Transactions													
Fixed Price													
Rate Based Assets													
Colstrip Unit 4	150,288	150,288	145,440	150,288	145,440	150,288	150,288	140,592	150,086	145,440	89,688	82,416	1,650,542
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
Spion Kop	8,184	8,184	9,360	14,136	14,400	11,904	17,856	11,136	11,888	11,520	8,928	8,640	136,136
Base Fixed Price Purchases													
Judith Gap	22,786	25,190	27,631	42,916	48,042	55,493	59,351	44,721	42,828	40,523	35,181	28,766	473,428
Other Small PPAs	12,403	10,802	6,744	5,490	3,605	3,720	3,720	3,480	3,715	3,600	8,355	11,967	77,602
Competitive Solicitations	20,800	20,800	20,000	21,600	19,200	20,800	20,000	20,000	21,600	20,800	20,000	20,800	246,400
QF Tier II	59,154	60,334	67,568	70,792	72,882	76,390	72,237	65,514	75,487	74,522	75,031	57,153	827,066
QF Tier II Adjustments													
QF-1 Tariff	10,373	11,160	11,475	14,225	16,204	16,740	18,228	14,268	14,489	12,709	13,671	10,801	164,342
Term Fixed Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Term Fixed Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Index Price													
Base Index Price Purchases													
Basin Creek	6,525	13,271	9,153	4,768	5,879	10,691	4,727	3,265	4,050	1,258	835	1,132	65,555
Competitive Solicitations	10,400	10,400	10,000	10,800	9,600	10,400	10,000	10,000	10,800	10,400	10,000	10,400	123,200
Term Index Price Purchases	37,200	37,200	36,000	37,200	36,050	37,200	-	-	-	-	-	-	220,850
Term Index Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Spot Purchases	255,019	222,700	146,954	163,424	162,475	219,725	258,598	240,398	216,568	173,734	236,973	275,976	2,572,543
Spot Sales	(5,242)	(5,887)	(5,628)	(27,931)	(1,940)	(2,948)	(13,027)	(19,923)	(21,287)	(9,524)	(4,961)	(3,020)	(121,318)
Imbalance, Current Month Estim	-	-	-	-	-	-	-	-	-	-	-	-	-

Imbalance, Prior Month True-up	-	-	-	-	-	-	-	-	-	-	-	-	-
Imbalance, Accounting & BA Exp	-	-	-	-	-	-	-	-	-	-	-	-	-
Ancillary and Other													
Basin Creek Fixed Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
Basin Creek Variable Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
Operating Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Other Cost													
DSM Program & Labor Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM Lost T& D Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM Lost Revenue Adjustment													
Total Delivered Supply	593,098	569,649	489,736	512,917	536,877	615,611	607,186	538,154	535,432	490,023	498,908	510,071	6,497,665

Electric Tracker Projection Excluding Generation Assets Cost of Service
Total Supply Expense

	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Total
	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
Off System Transactions													
Fixed Price													
Base Fixed Price Purchases													
Competitive Solicitations	$ 2,314,000	$ 2,314,000	$ 2,232,200	$ 2,358,360	$ 2,189,400	$ 2,314,000	$ 2,269,640	$ 2,194,760	$ 2,356,800	$ 2,276,560	$ 2,269,640	$ 2,276,560	$ 27,365,920
Base Fixed Price Sales													
Competitive Solicitations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Term Fixed Price Purchases	$ 2,390,810	$ 2,390,810	$ 2,309,200	$ 2,418,630	$ 2,283,621	$ 2,390,810	$ 1,796,240	$ 1,720,160	$ 1,844,015	$ 1,782,880	$ 1,796,240	$ 1,782,880	$ 24,906,296
Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Index Price													
Base Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Base Index Price Sales													
Competitive Solicitations	$ (450,736)	$ (449,176)	$ (431,400)	$ (457,056)	$ (407,232)	$ (442,728)	$ (438,800)	$ (418,300)	$ (451,764)	$ (313,768)	$ (276,700)	$ (287,768)	$ (4,825,428)
Term Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Term Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Spot Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Spot Sales	$ (4,125,968)	$ (4,111,688)	$ (3,968,880)	$ (4,062,720)	$ (3,872,946)	$ (4,052,664)	$ (3,326,104)	$ (3,020,126)	$ (3,234,505)	$ (2,256,716)	$ (2,097,386)	$ (2,069,716)	$ (40,199,419)
On System Transactions													
Fixed Price													
Rate Based Assets													
Colstrip Unit 4													$ -
Dave Gates Generating Station													$ -
Spion Kop													$ -
Base Fixed Price Purchases													
Judith Gap	$ 723,447	$ 799,775	$ 877,289	$ 1,362,569	$ 1,525,322	$ 1,761,904	$ 1,884,400	$ 1,419,885	$ 1,359,803	$ 1,286,618	$ 1,116,985	$ 913,326	$ 15,031,323
Other Small PPAs	$ 732,443	$ 623,955	$ 352,508	$ 264,091	$ 139,694	$ 144,150	$ 144,150	$ 134,850	$ 143,956	$ 139,500	$ 464,627	$ 718,111	$ 4,002,035
Competitive Solicitations	$ 1,123,720	$ 1,123,720	$ 1,080,500	$ 1,166,940	$ 1,037,280	$ 1,123,720	$ 1,080,500	$ 1,080,500	$ 1,166,940	$ 1,123,720	$ 1,080,500	$ 1,123,720	$ 13,311,760

	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Total
QF Tier II	$ 2,295,176	$ 2,340,969	$ 2,621,630	$ 2,746,747	$ 2,827,840	$ 2,963,949	$ 2,802,802	$ 2,541,931	$ 2,928,900	$ 2,891,459	$ 2,911,213	$ 2,217,541	$ 32,090,157
QF Tier II Adjustments													
QF-1 Tariff	$ 718,097	$ 765,051	$ 779,664	$ 962,316	$ 1,093,194	$ 1,120,174	$ 1,217,839	$ 950,506	$ 972,557	$ 865,205	$ 932,457	$ 741,060	$ 11,118,120
Term Fixed Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Index Price													
Base Index Price Purchases													
Basin Creek	na	na	na	na	na	na	na	na	na	na	na	na	na
Competitive Solicitations	$ 429,936	$ 428,376	$ 411,400	$ 435,456	$ 388,032	$ 421,928	$ 418,800	$ 398,300	$ 430,164	$ 292,968	$ 256,700	$ 266,968	$ 4,579,028
Term Index Price Purchases	$ 1,264,624	$ 1,260,028	$ 1,215,600	$ 1,371,360	$ 1,317,960	$ 1,373,412	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,802,984
Term Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Spot Purchases	$ 11,052,539	$ 9,618,396	$ 6,339,581	$ 6,916,113	$ 6,892,184	$ 9,353,700	$ 11,347,263	$ 10,055,838	$ 9,059,032	$ 5,241,564	$ 6,557,051	$ 7,636,249	$ 100,069,510
Spot Sales	$ (147,720)	$ (165,366)	$ (157,865)	$ (993,785)	$ (69,180)	$ (105,509)	$ (424,159)	$ (618,410)	$ (660,748)	$ (213,242)	$ (101,849)	$ (62,001)	$ (3,719,835)
Imbalance, Current Month Estim	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Imbalance, Prior Month True-up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Imbalance, Accounting & BA Exp	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
<u>Ancillary and Other</u>													
Basin Creek Fixed Costs	$ 355,755	$ 356,089	$ 361,576	$ 356,738	$ 792,573	$ 361,465	$ 375,308	$ 365,231	$ 353,305	$ 356,450	$ 777,549	$ 354,039	$ 5,166,077
Basin Creek Variable Costs	$ 276,188	$ 567,472	$ 387,307	$ 202,685	$ 257,848	$ 479,817	$ 211,893	$ 146,196	$ 180,150	$ 48,448	$ 31,675	$ 42,907	$ 2,832,586
Operating Reserves	$ 229,152	$ 229,152	$ 221,760	$ 229,152	$ 221,760	$ 229,152	$ 229,152	$ 206,976	$ 229,152	$ 221,760	$ 229,152	$ 221,760	$ 2,698,080
Wind Other Cost													
DSM Program & Labor Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM Lost T& D Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DSM Lost Revenue Adjustment													
Total Delivered Supply	$ 19,181,464	$ 18,091,563	$ 14,632,070	$ 15,277,596	$ 16,617,349	$ 19,437,279	$ 19,588,924	$ 17,158,298	$ 16,677,757	$ 13,743,406	$ 15,947,854	$ 15,875,635	$ 202,229,194

Electric Tracker Projection Excluding Generation Assets Cost of Service
Unit Costs

	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Total
	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
<u>Off System Transactions</u>													
Fixed Price													
Base Fixed Price Purchases													
Competitive Solicitations	$ 58.73	$ 58.73	$ 58.74	$ 58.67	$ 58.82	$ 58.73	$ 58.80	$ 58.68	$ 58.66	$ 58.67	$ 58.80	$ 58.67	$ 58.73
Base Fixed Price Sales													
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
Term Fixed Price Purchases	$ 36.11	$ 36.11	$ 36.08	$ 36.32	$ 35.86	$ 36.11	$ 38.06	$ 38.40	$ 38.46	$ 38.42	$ 38.06	$ 38.42	$ 37.02
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
Index Price													
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
Base Index Price Sales													
Competitive Solicitations	$ 43.34	$ 43.19	$ 43.14	$ 42.32	$ 42.42	$ 42.57	$ 43.88	$ 41.83	$ 41.83	$ 30.17	$ 27.67	$ 27.67	$ 39.17
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

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
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
Spot Sales	$ 43.34	$ 43.19	$ 43.14	$ 42.32	$ 42.42	$ 42.57	$ 43.88	$ 41.83	$ 41.83	$ 30.17	$ 27.67	$ 27.67	$ 39.58
On System Transactions													
Fixed Price													
Rate Based Assets													
Colstrip Unit 4													$ -
Dave Gates Generating Station													$ -
Spion Kop													$ -
Base Fixed Price Purchases													
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
Other Small PPAs	$ 59.05	$ 57.76	$ 52.27	$ 48.10	$ 38.75	$ 38.75	$ 38.75	$ 38.75	$ 38.75	$ 38.75	$ 55.61	$ 60.01	$ 51.57
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
QF Tier II	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80	$ 38.80
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
QF-1 Tariff	$ 69.23	$ 68.55	$ 67.95	$ 67.65	$ 67.46	$ 66.92	$ 66.81	$ 66.62	$ 67.13	$ 68.08	$ 68.21	$ 68.61	$ 67.65
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
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
Index Price													
Base Index Price Purchases													
Basin Creek	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
Competitive Solicitations	$ 41.34	$ 41.19	$ 41.14	$ 40.32	$ 40.42	$ 40.57	$ 41.88	$ 39.83	$ 39.83	$ 28.17	$ 25.67	$ 25.67	$ 37.17
Term Index Price Purchases	$ 34.00	$ 33.87	$ 33.77	$ 36.86	$ 36.56	$ 36.92	n/a	n/a	n/a	n/a	n/a	n/a	$ 35.33
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
Spot Purchases	$ 43.34	$ 43.19	$ 43.14	$ 42.32	$ 42.42	$ 42.57	$ 43.88	$ 41.83	$ 41.83	$ 30.17	$ 27.67	$ 27.67	$ 38.90
Spot Sales	$ 28.18	$ 28.09	$ 28.05	$ 35.58	$ 35.66	$ 35.79	$ 32.56	$ 31.04	$ 31.04	$ 22.39	$ 20.53	$ 20.53	$ 30.66
Imbalance, Current Month Estim	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
Imbalance, Prior Month 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
Imbalance, Accounting & BA Expense													
Ancillary and Other													
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
Basin Creek Variable Costs	$ 42.33	$ 42.76	$ 42.31	$ 42.51	$ 43.86	$ 44.88	$ 44.82	$ 44.78	$ 44.48	$ 38.50	$ 37.93	$ 37.92	$ 43.21
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
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
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
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
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
Total Delivered Supply	$ 32.34	$ 31.76	$ 29.88	$ 29.79	$ 30.95	$ 31.57	$ 32.26	$ 31.88	$ 31.15	$ 28.05	$ 31.97	$ 31.12	$ 31.12

PSC-352

Regarding: Property Taxes
Witness: Kliewer

In Docket D2008.6.69, the CU4 docket; NWE proposed to use the purchase price for CU4 as the basis for its property tax estimate. NWE later adjusted its revenue requirements in Docket D2009.12.155 to reflect the actual DOR assessment and value. NWE proposes to do the same in this docket.

a. Please explain why NWE chose to use an estimate rather than the last known and measurable property tax assessment.

b. Please provide supporting documentation from DOR supporting the hydro valuation used for your property tax estimation.

c. What was DOR's most current year's assessed value of the hydros?

d. What was the most current year's property taxes paid or incurred by PPL for the hydros that are being purchased?

e. What is the most current year's property taxes paid or incurred by PPL for Kerr Dam?

RESPONSE:

a. NorthWestern used an estimate applying known Montana Department of Revenue ("DOR") valuation methodology to develop the best possible estimate of hydro property taxes after purchase from PPLM.

b. NorthWestern does not have supporting documentation from DOR. Our best possible estimate was based on established valuation methods used by DOR in their various annual property tax valuation reports issued to NorthWestern over the years. DOR will not officially compute its valuations until May of 2015. Once final valuation numbers and property taxes are known, true-up adjustments can be made as has been done in the past.

c. For Tax Year 2013, PPLM had a Market Value of $414,824,267 and a Taxable Value of $24,889,462 for the hydros. See Attachment.

d. For Tax Year 2013, PPLM had property tax bills of $12,386,568 for the hydros. See Attachment provided in part c, above.

PSC-352 cont'd

e. For Tax Year 2013, PPLM had property tax bills of $1,018,332 for Kerr Dam (Lake and Flathead Counties). See Attachment provided in part c, above.

PPLM Hydro Related Property Taxes
Year 2013

2013 Hydro Related Property Taxes Bill Detail *Cost to Market Factor* *0.619071* *0.06 Tax Rate*

# of Bills	County	Cty #	Parcel #	County District	Tax District	Cost	Market Value	Taxable Value	Mill Levy	General Taxes	Specials	Total Bill
1	Cascade	02	2735610	1-A	A098	381,538,895	236,199,562	14,171,976	515.27	7,302,394.07	500.00	7,302,894.07
2	Cascade	02	2735611	1-C	C098	790,761	489,537	29,372	535.51	15,729.00	1,652.06	17,381.06
3	Cascade	02	5380710	29A2	2112	38,216,457	23,658,690	1,419,522	516.99	733,878.68	-	733,878.68
4	Lewis & Clark	05	36787	0111	2487-11	17,720,035	10,969,955	658,198	620.38	408,332.88	7,569.28	415,902.16
5	Lewis & Clark	05	36803	1302	0495-02	36,779,991	22,769,416	1,366,166	472.89	646,046.24	11,762.69	657,808.93
6	Gallatin	06	RSB20021	69R 50	2373-50	29,593,655	18,320,566	1,099,235	426.20	468,493.96	7,440.26	475,934.22
7	Madison	25	27601600	52F	2545	10,149,555	6,283,292	376,998	290.81	109,634.79	-	109,634.79
8	Madison	25	16600500	23FH	2542	2,869,394	1,776,358	106,581	519.83	55,404.00	-	55,404.00
9	Stillwater	32	7000038	13-O	1853	8,254,159	5,109,908	306,593	417.17	127,901.41	266.27	128,167.68
10	Sanders	35	6059	2R	1804	85,435,671	52,890,723	3,173,444	441.18	1,400,060.03	71,169.62	1,471,229.65
11	Lake	15	150082	23	1477	119,239	73,817	4,429	455.03	2,015.33	-	2,015.33
12	Lake	15	150081	23PR	3477	56,283,703	34,843,593	2,090,617	467.89	978,178.79	-	978,178.79
13	Flathead	07	S009061	29	0327	565,587	350,138	21,008	460.68	9,678.09	-	9,678.09
14	Flathead	07	S009063	38	0330	341,061	211,141	12,668	414.17	5,246.90	-	5,246.90
15	Flathead	07	S009060	09	0316	113,691	70,383	4,223	498.90	2,106.84	-	2,106.84
16	Flathead	07	S009058	03	0308-01	151,080	93,529	5,612	516.43	2,898.07	-	2,898.07
17	Flathead	07	S009059	05	1310	22,739	14,077	845	529.77	447.45	-	447.45
18	Flathead	07	S009062	48	1327	1,130,050	699,581	41,975	423.13	17,760.82	-	17,760.82
					Totals	**670,075,723**	**414,824,267**	**24,889,462**		**12,286,207.36**	**100,360.18**	**12,386,567.54**

PSC-353
Regarding: Choice Customers
Witness: Hines, part a / Mike Cashell, parts b & c

At a listening session in Great Falls, one choice customer expressed concern about the ability to receive energy supply from PPLM if the Hydro transaction were consummated, because of limited transmission availability from Colstrip (PPLM's remaining facilities) to Great Falls.

a. With respect to energy supply, is there an option for these customers to be served by NWE, instead of PPLM, at a rate that retains these customers' access to low, market-based prices?

b. With respect to transmission, please explain the difficulties of transmitting energy supply from PPLM's remaining assets at Colstrip to Great Falls. Would these choice customers have transmission access available to them?

c. How many choice customers remain in Great Falls who would be affected by this issue, and (if it is known to you) what is the total load in question?

RESPONSE:

a. NorthWestern does not have access to information to support the representation that these customers' rates are low. Further, NorthWestern does not have access to the supply contracts between choice customers and PPLM. The Commission, under § 69-8-201(1) and (2), MCA, has ultimate responsibility for tariffs and determining whether a choice customer can be served by NorthWestern.

b. Under the open access transmission tariff (OATT), transmission capacity is awarded on a first-come-first-served basis, based on when the transmission request is received in relation to other transmission requests in the transmission queue, which is publicly available. All network customers, including choice customers, have the right to choose which network resources they desire to designate but must follow the terms of the tariff, including transmission availability. Choices for energy supply are made between the network customer and their supplier based on commercial terms, such as price, but the customer must also consider transmission availability. The supply transaction itself does not affect NorthWestern's queue.

Currently there is significant competition for transmission capacity on the NorthWestern transmission system. These requests can affect capacity into and out of the Great Falls area.

PSC-353 cont'd

If the Hydro assets transfer to NorthWestern, then the Network Customer (Choice Customer) will be required to designate a new network resource. This process is prescribed by the OATT in great detail, and there are limitations, including available capacity on the Transmission System, that must be considered by NorthWestern in this process. We will be notifying Choice Customers of the requirement as appropriate.

c. Below is a table of existing Choice Customers in the Great Falls area and their Network Designations effective July 1, 2014.

Starting July 1, 2014			
Choice Customer	**MW Load**	**Location**	**Designation**
Benefis Health Systems	4	Great Falls, MT	Colstrip 1&2
City of Great Falls	4	Great Falls, MT	Crooked Falls (Ryan, Rainbow, Cochrane, Morony)
General Mills	4	Great Falls, MT	Crooked Falls (Ryan, Rainbow, Cochrane, Morony)
Great Falls Public Schools	1	Great Falls, MT	Crooked Falls (Ryan, Rainbow, Cochrane, Morony)
Montana Refining Company	4	Great Falls, MT	Crooked Falls (Ryan, Rainbow, Cochrane, Morony)
Suiza Dairy	1	Great Falls, MT	Crooked Falls (Ryan, Rainbow, Cochrane, Morony)
Conoco	14	Great Falls Area	Crooked Falls (Ryan, Rainbow, Cochrane, Morony)
Central Montana Electric Co-Op	2	Great Falls, MT	Power Contract Importing at Crossover
Total	34		

NorthWestern Energy
Docket D2013.12.85
PPLM Hydro Assets Purchase

Public Service Commission (PSC)
Set 14 (305-354)

Data Requests served May 23, 2014

PSC-354
Regarding: Water Rights
Witness: Rhoads

At various public meetings, water rights have surfaced as an issue of public comment and concern.

a. Would all water rights currently held by PPLM transfer to NWE as a result of this transaction? Please identify where in the PPL-NWE agreement this matter is addressed.

b. Are there any concerns that there are rival, potentially precedent claims on those water rights that would undermine NWE's ability in the future to use the water for the purpose of electric generation? Explain, and provide supporting documents or memoranda is they exist.

RESPONSE:

a. All water rights held by PPLM related to or held for use in connection with the Acquired Assets will transfer to NorthWestern (see Article II Section 2.1 (a)(iii) of the Purchase and Sale Agreement ("PSA")). Per the PSA, PPLM is required to deliver at Closing all necessary documentation to transfer and convey to NorthWestern the Water Rights (including Fee Log Sheets in the form promulgated by the Montana Department of Natural Resources and Conservation) (see Article II Section 2.6 (j) of the PSA).

b. NorthWestern is not aware of any precedent claims on the water rights that would undermine its ability in the future to use the water to generate electricity.