NorthWestern® Energy

Before The Public Service Commission
Of the State of Montana

DOCKET NO. D2013.12.85

APPLICATION FOR APPROVAL TO OWN AND OPERATE
PPL MONTANA'S HYDROELECTRIC FACILITIES,
FOR APPROVAL OF INCLUSION OF GENERATION ASSET COST OF SERVICE
IN ELECTRICITY SUPPLY RATES,
FOR APPROVAL OF ISSUANCE OF SECURITIES
TO COMPLETE THE PURCHASE, AND FOR RELATED RELIEF

ADDITIONAL ISSUES
TESTIMONY AND EXHIBITS

APRIL 2014

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.12.85
PPLM Hydro Assets Purchase
NorthWestern Energy

PREFILED ADDITIONAL ISSUES TESTIMONY OF

WILLIAM T. RHOADS

ON BEHALF OF NORTHWESTERN ENERGY

Exhibits

Essex Checklist Augmented by NorthWestern	Exhibit__(WTR-10) *(provided on CD)*

Witness Information

Q. What is your name, business address, and occupation?

A. My name is William T. Rhoads. My business address is 40 East Broadway, Butte, Montana. I am the General Manager, Generation for NorthWestern Energy ("NorthWestern") and report to Mr. John D. Hines, Vice-President - Supply.

Q. Are you the same William T. Rhoads who submitted prefiled direct testimony in this docket?

A. Yes I am.

Purpose of Testimony

Q. What is the purpose of this testimony?

A. I am testifying in response to additional issues identified by the Montana Public Service Commission ("Commission") in its April 4 Notice of Additional Issues ("Notice") and to the information provided to the Commission by its engineering consultant, The Essex Partnership ("Essex"), that led to the identification of additional issues. In its Notice, the Commission requested (1) additional information regarding "the structural integrity, physical condition, environmental liabilities, and the sufficiency of NorthWestern's due diligence effort for each of the individual facilities" and (2) information that will provide "a fuller understanding of what the range of potential future CapEx and O&M costs might be and the effect of those potential costs on NorthWestern's net present value cost estimates." On March 31, 2014, Essex submitted a checklist of due diligence items ("Checklist") to the Commission. On April 2, 2014, Essex submitted a memo summarizing its major findings ("Memo") regarding NorthWestern's due diligence of PPL Montana, LLC's ("PPLM") hydroelectric projects. In its Memo, Essex opined, "...the information in the docket to date does not contain sufficient information to confirm NWE's projections of capital or operations and maintenance (O&M) expenditures through the 20-year study period of the discounted cash flow analysis." My testimony, along with the testimony of other NorthWestern witnesses whom I introduce below, addresses the Commission's requests for additional testimony, the Memo, and the Checklist.

Q. Are all of the witnesses that you introduce below employees of NorthWestern?

A. No. As explained in my prefiled direct testimony, NorthWestern hired CB&I as an independent engineer to assist in the evaluation of the PPLM hydroelectric projects. CB&I's findings regarding the civil aspects addressed in the Essex Memo and Checklist are presented in the Prefiled Additional Issues Testimony of Gary Wiseman ("Wiseman Additional Issues Testimony").

In response to the Commission's hiring of Essex to perform a review of the due diligence, NorthWestern retained a third party independent engineering firm, HDR Engineering, Inc. ("HDR"), to conduct a peer review and provide both an independent opinion regarding the Essex Memo and Checklist and an independent review and opinion of NorthWestern's capital expense ("CapEx") cost projections. HDR is a multi-faceted global engineering firm involved in all aspects of hydro projects including due diligence, engineering, operations, design, construction, and environmental issues. HDR's findings are presented in the Prefiled Additional Issues Testimony of Rick Miller ("Miller Additional Issues Testimony").

Q. What is the basis of your testimony?

A. The basis of my testimony is my personal involvement as the lead in the due diligence process for NorthWestern. From NorthWestern's rigorous due diligence effort spanning approximately 12 months, NorthWestern concluded there were no material findings or issues that would prevent it from acquiring these assets. NorthWestern's process included:

- Review of technical, operational, and environmental materials contained in the PPL Corporation ("PPL") data room, including materials placed in the data room in response to questions from NorthWestern;
- Detailed discussions with knowledgeable PPL and PPLM management personnel;
- Reliance on institutional knowledge, understanding, and experience of the NorthWestern personnel involved in the due diligence process with these specific projects;
- Comprehensive visits to each of the sites; and
- Comprehensive review of the assets by an independent, global, and acclaimed third party engineering firm, CB&I, using experienced technical personnel.

NorthWestern reached sound conclusions about the long-term adequacy of the hydro assets. The conclusions in NorthWestern's assessment of the physical condition, operation, maintenance, engineering, and resource management of each of the hydro facilities are based on the extensive

hydro due diligence effort in its entirety, including the institutional knowledge of these hydro plants possessed by NorthWestern's due diligence team and the findings of CB&I.

Q. Please describe the additional issue testimony NorthWestern is offering.

A. My testimony explains NorthWestern's overall approach toward responding to the issues raised by Essex and addresses specific issues related to the equipment section in the Memo. The Wiseman Additional Issues Testimony addresses the civil aspects, the Prefiled Additional Issues Testimony of John VanDaveer addresses the CapEx issues, and the Prefiled Additional Issues Testimony of Mary Gail Sullivan discusses the environmental liabilities and regulatory compliance areas. I described the Miller Additional Issues Testimony above.

The Essex Memo and Checklist

Q. How does the level of Essex's review compare to NorthWestern's due diligence effort?

A. The Essex review was not conducted at the same level of completeness as the due diligence conducted by NorthWestern. Essex did not interview PPL or PPLM personnel familiar with managing and operating the hydro assets, did not conduct site visits, and did not have the full benefit of the institutional knowledge possessed by the NorthWestern due diligence

team regarding the assets. In short, Essex's review, upon which it bases its conclusions, was neither as detailed nor as comprehensive as NorthWestern's due diligence effort or that of its independent consultant, CB&I.

Q. What is your assessment of the Memo, the Checklist, and their conclusions?

A. Essex raised unfounded concerns about the PPLM assets based upon generalities regarding the civil, equipment, environmental liabilities, and regulatory compliance.

Q. Did Essex reach general conclusions that you want to address?

A. Yes. Essex indicated in its Checklist that certain information was classified as "unknown." NorthWestern and Essex held an informative conference call on February 7, 2014. In addition, NorthWestern provided voluminous information in its response to Data Request PSC-179. Essex had access to the PPLM data room and to all of NorthWestern's responses to discovery from the Commission and the Montana Consumer Counsel. Essex and the Commission indicated the record was not complete; yet they had from February 7 to February 21, 2014 to request additional specific information either through data requests or additional conference calls needed to complete their review.

In addition, Essex draws conclusions about replacement of certain equipment as a matter of "industry practice". These conclusions are misleading. Wholesale replacement of currently functioning equipment would require incurring significant cost that at this time is difficult to justify and is not an "industry practice." Maintaining currently functioning equipment is an equally valid and adequate choice. These issues are thoroughly discussed in the Wiseman Additional Issues Testimony.

Q. How is the Essex Checklist organized?

A. The Essex Checklist contains separate spreadsheet files for each of the 12 projects that contain information regarding the civil, electrical, mechanical, and resource categories. The Essex Checklist provides general observations about the system.

Q. Please explain how NorthWestern is responding to the individual line items identified in the Essex Checklist.

A. In order to address the concerns raised by the Commission, NorthWestern started with the Essex Checklist, made up of the 12 electronic spreadsheets, and added five columns. Because portions of these modified spreadsheets include CEII information, they are provided on two accompanying CDs, one public and one protected, as Exhibit__(WTR-10). The additional columns are:

Cap Ex or O&M: This column indicates whether the repair or replacement would be categorized as a capital expenditure or an O&M expenditure. Generally, a cost is capitalized if a unit of replacement can be retired or identified as a "retireable unit" or the replacement is an upgrade to the item being replaced. For instance, the replacement of an entire generator winding, made up of many individual coil components, is considered a capital expenditure because the winding is a retireable unit, and the new winding usually has an increased capacity rating due to new winding materials and manufacturing methods. However, if a coil or set of coils within the existing winding is repaired, the expenditure is considered a maintenance expense, not a capital expense, because the entire winding is not retired, but the winding is repaired in place. "Rewedging" of individual coils in a winding, which is a maintenance practice used to retighten the coil into the generator "slot" to prevent the coil from vibrating loose, is another example of a maintenance expense.

Included in Cap Ex or O&M: This column represents whether the item is included in the 20-year budget forecast as CapEx or O&M. If a significant capital project is planned, the forecast will identify the item and the plant. The NorthWestern proposed budgets can also absorb unplanned items by reprioritization of projects in a specific year. For instance, depending on the item and the time of the year, an unplanned event could be prioritized

into the budget while deferring a budget item of lower priority without an impact on safety or reliability.

Likelihood of Occurrence: This column represents an opinion by a qualified person of whether the item will likely be in need of maintenance or replacement within the 20-year budget forecast period. Based upon the condition of a piece of equipment, an item is identified as "unlikely" if it is not expected to require a significant expenditure for repair or replacement in the next 20 years. In cases where work is planned or the condition is such that there is increased likelihood that a CapEx or O&M expenditure may be necessary, the item is classified as "likely." This column is particularly helpful for those items that are included as maintenance and which are inspected and repaired on a routine basis.

Planned Timing: This column indicates if the item is planned for repair or replacement. The column pertains to those items that are included in the 20-year CapEx or O&M budget.

Comments: This column provides space for more explanation to clarify the condition or status of the equipment.

Q. You mentioned that you would address the equipment section contained in the Essex Memo. Please do so.

A. Please note that the equipment section of the Memo discusses equipment in both the electrical and mechanical tabs in the Essex Checklist spreadsheet. The Essex Memo stated that the case file provides "little information on the condition, performance, or reliability of the turbine generators, governors, or other equipment." NorthWestern's thorough due diligence process reviewed these items. The purpose of NorthWestern's due diligence process was to investigate the status of the assets to determine if there were any material deficiencies that should prevent NorthWestern from offering to purchase the assets. From its due diligence process cited earlier in my testimony, the due diligence team did not find any material items which rose to a level of concern. NorthWestern provided the Commission with the information it needs to conclude that there is a complete record on due diligence in this proceeding. With this filing, NorthWestern is responding to the Commission's request for additional information regarding the civil, electrical, mechanical, and environmental aspects of each plant. NorthWestern has included this information on Exhibit__(WTR-10) and in Additional Issues Testimony. This additional information further demonstrates that the equipment is maintained on a routine basis, its condition is known to a satisfactory level, and its upgrade and/or replacement costs are timed to levelize budget expenditures to the extent these expenditures can be planned.

Q. Essex commented on several specific pieces of equipment in its Memo to the Commission. Please address these comments.

A. Essex's Memo cited three areas of concern including 1) turbines, generators and associated equipment; 2) generator step up transformers; and 3) the capability of the interconnected transmission system. I will address them sequentially.

1) Turbines, generators and associated equipment: Let me start my explanation with the saying, "Scheduled downtime is always best." No business rationale prefers an unscheduled breakdown and the problems that can arise as a result of an unplanned outage. Therefore, the operation, maintenance, and improvements to the system are aligned with safety, environmental protection, and asset preservation. Over the years, the driver for replacement of turbines, generator windings, and ancillary equipment has been a condition-based program using field observations during planned maintenance intervals. Planned inspection and maintenance extends equipment life so its replacement does not need to fit a time-based replacement program. For example, some of the original turbine runners and generator windings are over 50 years old and are still functioning as they did when they were originally installed.

Performance improvements may be possible with the turbine runner replacement or refurbishment, seal repair, stator and winding

replacement, and rotor replacement such as with Morony Unit #1 where upgrade work is currently in progress. However, for the purpose of the hydro asset evaluation, incremental efficiency gain potential is not included in the annual production assumptions used in the financial models. So a baseline status of capability is known, and, going forward, determinations can be made to identify and consider equipment improvements.

PPLM has been working toward a more aggressive maintenance strategy for individual equipment classes. Specific to turbine generators, the equipment is inspected on planned maintenance intervals and if water conditions allow. Water wheels in need of cavitation repair are welded, and the cooling slots in the generator stator iron are cleaned. (Cavitation refers to a condition caused by the normal operation of a hydroelectric generator. A hydroelectric turbine generator has a water wheel. As water flows past the rotating water wheel and into the river, it creates an air vacuum which causes an "explosion" of water bubbles on the downstream side of the water wheel. This explosion of water bubbles causes the raw material to be pulled away from, or cavitate, the water wheel.) Generator winding resistance is checked if possible to ensure insulation levels are still intact. When possible, units are checked for hot spots using a "thermograph." Concentrated hot spots can accelerate winding deterioration. This plan from PPLM, which will be continued by

NorthWestern, will advance equipment monitoring, testing, recordkeeping, and trending analysis.

2) Generator step up ("GSU") transformers: The GSU dissolved gas analyses ("DGA") at some locations were reported as an IEEE Category IV. The DGA tests for eight different gases including hydrogen, methane, acetylene, ethylene, ethane, carbon monoxide, carbon dioxide, and total dissolved combustible gas. The IEEE Category IV rating for some transformers on the PPLM hydro system is a result of elevated carbon monoxide and carbon dioxide levels, which, when generated, do not vent to the atmosphere but remain in the transformer. These two gases are generated from off gassing of the extensive amount of cellulose insulation inside the transformer. The heightened level of carbon monoxide and carbon dioxide may impact transformer life many years down the road but is not a concern for the transformers on the PPLM hydro system. The basis for the IEEE Level IV condition in this case is an acceptable and low-level risk to the affected plants based upon my personal discussions with PPLM's consultant and transformer and substation expert. If the gas analysis showed a hydrocarbon was present such as acetylene (perhaps caused by electrical arcing inside the transformer), then additional monitoring and possibly further investigation regarding its source would be necessary.

3) The capability of the interconnected transmission system: A valid hydro interconnection agreement is in place for each of the PPLM hydro facilities.

The lead lines from the plants to the point of interconnection are in overall good condition. Thompson Falls, Kerr, Hauser, and Holter have points of interconnection located at or very close to the plant so exposure to transmission line-related outages are less than those with longer lead lines. The lead lines for the Great Falls plants were recently rebuilt and connect into the new Crooked Falls Switchyard located near Rainbow Dam (except for the Black Eagle Plant, which connects into the Great Falls Riverview Substation). One pole line from the Mystic Plant to the point of interconnection was rebuilt, but may be reconductored in the next 5 to 10 years. This cost has been included in the 20-year CapEx budget. Another parallel pole line is also budgeted to be replaced and reconductored and is also included in the 20-year CapEx budget.

Q. What is your overall conclusion regarding the Essex review?

A. Essex's review, upon which it based its faulty conclusions, was neither as detailed nor as comprehensive as NorthWestern's due diligence effort. As a result, the conclusions it reached in its Memo and Checklist are incomplete and/or inaccurate. If Essex had performed a comprehensive review of the assets as NorthWestern and CB&I did, I believe that Essex

would have also concluded that **there is no issue related to due diligence that rises to a level of materiality in this transaction.**

Other Witnesses

Q. Please introduce the NorthWestern witnesses who sponsor Additional Issues Testimony in addition to those you previously identified.

A. Travis Meyer presents the impacts to revenue requirements associated with a 30% increase in CapEx costs as well as a 15% decrease in CapEx costs as described in the VanDaveer Additional Issues Testimony.

Joseph Stimatz incorporates the revenue requirement adjustments into the portfolio analysis.

Q. Does this conclude your testimony?

A. Yes it does.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.12.85
PPLM Hydro Assets Purchase
NorthWestern Energy

PREFILED ADDITIONAL ISSUES TESTIMONY OF

JOHN C. VANDAVEER

ON BEHALF OF NORTHWESTERN ENERGY

Witness Information

Q. Please state your name and business address.

A. My name is John C. VanDaveer. My business address is 40 East Broadway, Butte, Montana.

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

A. I am employed by NorthWestern Energy ("NorthWestern") as the Manager of the Hydroelectric Acquisition Transition Project. I report to William T. Rhoads, the General Manager of Generation. Specific to this testimony, as part of the NorthWestern due diligence team, I participated directly in development of NorthWestern's capital and operations and maintenance expense ("CapEx" and "O&M" respectively) forecasts in this docket.

Q. Please describe your relevant education and employment history.

A. I graduated from Montana State University with a Bachelor of Science degree in Civil Engineering in 1979. I started work for the Montana Power

Company in 1979 in the electric distribution department. In 1985, I transferred to the generation department and began work for hydroelectric and thermal generation operations. I supervised the hydroelectric engineering department and then managed the engineering and operations functions until 1999. I then was the Manager of Hydroelectric Operations for PPL Montana, LLC ("PPLM"), a position that included responsibility for the operation, engineering, and license management functions, through 2005. I returned to NorthWestern as the Butte Division Distribution Operations Manager in 2008 and assumed my current position in October 2013. I am a registered Professional Engineer in Montana.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I am testifying in response to additional issues identified by the Montana Public Service Commission ("Commission") in its April 4, 2014 Notice of Additional Issues ("Notice") and to the information provided to the Commission by The Essex Partnership ("Essex"), its engineering consultant, that led to the identification of additional issues. In its Notice, the Commission requested 1) additional information regarding "the structural integrity, physical condition, environmental liabilities, and the sufficiency of NorthWestern's due diligence effort for each of the individual facilities" and 2) information that will provide "a fuller understanding of what the range of potential future CapEx and O&M costs might be and the

effect of those potential costs on NorthWestern's net present value cost estimates." On March 31, 2014, Essex submitted a due diligence checklist ("Checklist"). On April 2, 2014, Essex submitted a memo summarizing its major findings regarding NorthWestern's due diligence of PPLM's hydroelectric projects ("Memo"). In the Memo, Essex asserted, "...the information in the docket to date does not contain sufficient information to confirm NorthWestern's projections of capital or operations and maintenance (O&M) expenditures through the 20-year study period of the discounted cash flow analysis." My testimony describes NorthWestern's development of its projected CapEx, discusses the possible range of CapEx, responds to the Memo, and explains why NorthWestern does not offer a range for forecast O&M.

CapEx Projections

Q. Why is NorthWestern's CapEx forecast the best basis for analyzing the hydro acquisition?

A. The CapEx cost forecast prepared by the NorthWestern due diligence team is the best basis for analyzing the future O&M of the system because of the due diligence team's capability, the process it followed, and the confirmation the forecast received from two external independent evaluations.

Q. Summarize the capability of NorthWestern's due diligence team.

1 **A.** The due diligence team primarily included William Rhoads, Mary Gail
2 Sullivan, and me, all NorthWestern employees, and Gary Wiseman of
3 CB&I, Inc., an independent consultant. I, personally, have 20 years of
4 electric generation experience primarily with the PPLM hydro system from
5 1985 through 2005 as a civil engineer, supervisor, and manager in every
6 aspect of the operation and business. William Rhoads has over 25 years
7 of experience in electric generation with the majority of this experience
8 associated with the PPLM hydro system operations. Mary Gail Sullivan
9 has 10 years of experience in the Federal Energy Regulatory Commission
10 license aspects of the hydroelectric system. Additional detail regarding
11 my experience as well as the experience of Mr. Rhoads and Ms. Sullivan
12 is included in Exhibit__(WTR-1) attached to the Prefiled Direct Testimony
13 of William Rhoads. Gary Wiseman has over 40 years of hydro industry
14 experience. Mr. Wiseman's experience is further described in his Prefiled
15 Additional Issues Testimony ("Wiseman Additional Issues Testimony").
16
17 Importantly, through this collective number of years of direct involvement
18 with this system, the team has developed the knowledge and experience
19 necessary to fully understand the specific condition and operation of this
20 system and credibly establish the CapEx and O&M forecasts to
21 adequately sustain its performance.
22
23 **Q. How did the due diligence team determine the CapEx forecast?**

A. The team conducted a thorough review of information in the PPLM data room and other pertinent information, conducted site evaluations at every development, and discussed the operations, maintenance and upgrade status and strategies with the knowledgeable PPLM employees throughout the system. This due diligence work was performed over a period of approximately 12 months concluding in September 2013. NorthWestern's due diligence effort was comprehensive, covering the regulatory environment in which the system is operated, the operational capability itself, the maintenance performed on the system, and the strategic investments made in the system to date. Based on its experience and knowledge and the comprehensive approach defined above, the team projected CapEx expenses by evaluating and integrating the PPLM five-year forecast for 2013 through 2017 into a 20-year plan. Additionally, the 20-year plan included the remaining major investment upgrades needed on the system that had not been addressed in the PPLM CapEx investments prior to 2013 and specifically planned from 2013 through 2017. The balance of the unspecified capital budget for the 20-year plan was determined to be sufficient to sustain minor generation and non-operational capital projects. The PPLM actual capital investments for 2008-2012 provided further justification that major CapEx equipment and structural projects for strategic system reliability had been completed or were near completion.

1 **Q. Does Essex reach an inaccurate conclusion regarding**
2 **NorthWestern's overall CapEx forecast?**
3 **A.** Yes. A significant and inaccurate conclusion that Essex reaches on page
4 3 of its Memo is that the future level of capital expenditure should be
5 greater than that projected by NorthWestern.
6
7 **Q. Why is this conclusion inaccurate?**
8 **A.** Specifically, Essex adjusted the PPLM actual CapEx for 2008-2011 and
9 then averaged for an amount of $5.249M that represents their annual
10 CapEx. NorthWestern used the same PPLM actual annual costs less
11 major projects evaluated with the 2013-2017 detailed CapEx, O&M actual
12 and forecast and the strategic system investments made to date. Our
13 evaluation resulted in the annual capital requirement of $8.5M which was
14 escalated at 2.5% from 2018 forward. Essex escalated its amount of
15 $5.249M at 2.5% to the year 2021 for a total base sustenance CapEx
16 amount of $6.888M. The year 2021 was conveniently selected because it
17 represented the only year that NorthWestern specifically identified four
18 developments for major capital projects. The Essex arithmetic suggests
19 that the NorthWestern forecast is short based on its number exercise to
20 complete annual sustenance capital work. This is a selective number
21 manipulation that does not represent a comprehensive capital evaluation
22 due diligence effort. Nor does it represent the fact that companies, such
23 as NorthWestern, would manage the whole fleet over time with a strategic

1 plan through the years. In contrast, our due diligence concludes that the
2 strategic and significant investments that have occurred on the hydro
3 system reduce the future capital expenditures needed to sustain a high
4 future level of operation. This fact is described in NorthWestern's prefiled
5 direct testimony and information provided in response to discovery in this
6 docket. Major generation units and balance of plant have been
7 modernized with a finite level of material remaining work identified and
8 included in the CapEx forecast. That is the basis and relevance of
9 NorthWestern's CapEx forecast. Specific additional detail that
10 substantiates the development and content of the NorthWestern CapEx
11 forecast is provided in the Prefiled Additional Issues Testimony of William
12 Rhoads ("Rhoads Additional Issues Testimony") and the Wiseman
13 Additional Issues Testimony, including the information added by
14 NorthWestern in the expanded Essex Checklist attached as
15 Exhibit__(WTR-10) to the Rhoads Additional Issues Testimony.
16
17 **Q. Did any independent evaluation confirm the due diligence team's**
18 **CapEx forecast?**
19 **A.** Subsequent to this due diligence work, an additional independent
20 evaluation of the team's conclusions was performed by HDR Engineering,
21 Inc. ("HDR") that confirmed the NorthWestern team's work. Mr. Rick Miller
22 and his team at HDR performed an independent review of NorthWestern's
23 due diligence on the NorthWestern/CB&I CapEx plan and forecast. HDR

1 concluded that the CapEx plan and forecast are credible and appropriate
2 for system sustainability. Unlike the Essex process, the HDR due
3 diligence work assessed the comprehensive NorthWestern/CB&I
4 evaluation that included all of the system influences that are critical to a
5 credible cost forecast. The conclusions and detailed information that
6 support the NorthWestern CapEx are included in the Prefiled Additional
7 Issues Testimony of Rick Miller.
8
9 **Q. Has NorthWestern conducted a sensitivity analysis that illustrates**
10 **the impact of capital costs at levels above NorthWestern's forecast?**
11 **A.** Yes. NorthWestern understands that every possible future exposure
12 cannot be identified. Its comprehensive due diligence of all the aspects of
13 the system leads to the conclusion that the system is well managed,
14 operated, and planned for with manageable risk. We also understand that
15 opportunity projects designed to improve operation and/or increase
16 capability can develop or an unplanned event could occur. Although
17 NorthWestern believes its CapEx forecast is adequate and accurately
18 represents future capital needs, and it accommodates a reasonable
19 amount of variability, in accordance with the Commission's Notice,
20 NorthWestern conducted capital expenditure sensitivity analyses to
21 illustrate the effect of potential variances to CapEx expenses. The
22 analysis includes a scenario in which CapEx is increased by 30% and a
23 scenario in which CapEx is decreased by 15%. These extreme

assumptions consider the variance for each scenario to occur annually which is highly unlikely.

The Prefiled Additional Issues Testimonies of Joseph Stimatz and Travis Meyer include analyses that incorporate these extreme assumptions and describe their results.

Q. Did NorthWestern conduct any sensitivity analyses on O&M forecast expenses?

A. No. NorthWestern did not perform a sensitivity analysis on the O&M annual cost forecast for the hydro system. An analysis of the annual actual expenses performed by the due diligence team shows that the majority is employee labor and recurring regulatory required costs. An approximate level of only 20% of the expense budget is associated with annual work and projects subject to variability that do not meet capital criteria classification. Therefore, NorthWestern concludes that a sensitivity analysis addressing variability in future O&M costs is not necessary or appropriate.

Essex Memo and Checklist

Q. What conclusion did you reach upon review of the Essex Memo and Checklist regarding CapEx?

1 **A.** Our review of the Memo and Checklist lead us to conclude that the
2 questions surrounding our CapEx forecast result from a due diligence
3 process limited to review of documents filed in the docket. The Essex
4 conclusions are targeted at only one aspect of the entire body of work
5 performed by the NorthWestern team, future capital expenditures, based
6 on technical generalizations that are not necessarily specific to the PPLM
7 system.
8
9 **Q. Does this conclude your testimony?**
10 **A.** Yes it does.

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PREFILED ADDITIONAL ISSUES TESTIMONY OF

MARY GAIL SULLIVAN

ON BEHALF OF NORTHWESTERN ENERGY

Exhibits

Exhibit B of the *Missouri-Madison Project 2188 Fisheries, Wildlife, Habitat, and Water Quality Protection, Mitigation, and Enhancement Memorandum of Understanding* Exhibit__(MGS-1)

Witness Information

Q. Please state your name and business address.

A. My name is Mary Gail Sullivan. My business address is 40 East Broadway, Butte, Montana.

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

A. I am employed by NorthWestern Energy ("NorthWestern") as Manager of Environmental Permitting and Compliance. I report to William T. Rhoads, General Manager, Generation.

Q. Please describe your educational and work background.

1 **A.** I graduated from the University of Montana, School of Forestry in 1979
2 and started work at the Montana Power Company ("MPC") in 1980.
3 During my career at MPC, I held various environmental leadership
4 positions including Coordinator of Land Use and Recreation, Director of
5 Environmental Permitting, Director of Hydro Relicensing and Director of
6 Environmental Compliance. In 1998, the environmental audit function,
7 which was part of Environmental Compliance, was merged with internal
8 audit and I was named Director of Internal Audit. I held this position
9 through MPC's transformation from a diversified utility to a
10 telecommunications company. After bankruptcy in 2003, I continued
11 working in the telecom industry until March 2013, when I was hired by
12 NorthWestern in my current position.
13
14 My education also includes an MBA from the University of Montana in
15 2001 and the University of Idaho's Public Utilities Executive Course.
16
17 **Purpose of Testimony**
18 **Q. What is purpose of your testimony?**
19 **A.** The purpose of my testimony is to address the additional information
20 requested by the Montana Public Service Commission on environmental
21 topics. The focus will be on the forecasted cost of regulatory compliance
22 and environmental issues raised by The Essex Partnership ("Essex") due
23 diligence checklist.

Q. What is the forecasted amount for regulatory compliance and environmental issues?

A. The forecasted expense is $4,514,519 in 2013, the baseline year, and is found under the category, "Hydro License & Compliance" in the Operation and Maintenance ("O&M") forecast provided in response to Data Request MCC-028a, Attachment, page 2. Of this amount, $4,116,879 is attributed to compliance with environmental-related license conditions, including protection, mitigation and enhancement measures ("PM&E") and other environmental requirements with the remaining portion ($397,640) primarily supporting Part 12 compliance and the Emergency Action Plans. The line item breakdown is shown in the following table:

Project Description	2013 Baseline
TFalls License Administration & PM&E	$597,117
Kerr License Administration	$ 40,037
2188 License Administration	$750,481
Hydro Public Safety Administration	$ 20,000
2188 Madison Fisheries TAC PM&E	$358,740
2188 Missouri Madison Water Quality TAC PM&E	$225,000
2188 Missouri Madison Wildlife TAC PM&E	$331,144
2188 Missouri Fisheries TAC PM&E	$551,906
2188 Recreation PM&E Projects	$500,000
Mystic License Administration and PM&E	$497,422
TFalls Fish Passage & Sampling Facility O&M	$105,000
Kerr North Shore Project Monitoring	$ 50,000
Black Eagle Soil Remediation	$ 25,002
SPCC & Waste Management Plan	$ 30,030
FERC P12 Deficiencies	$151,779
FERC P12 & DSPMP	$180,743
FERC Emergency Action Plans	$ 35,000
FERC 2188 5 Year Shoreline Erosion Monitoring	$ 35,000
WECC Generator Testing	$ 30,118
TOTAL	**$4,514,519**

PPL Montana, LLC ("PPLM") provided these baseline numbers. NorthWestern escalated the numbers 2.5% annually to forecast expenses through 2036.

Q. Do you believe these numbers provide a reliable basis for NorthWestern's forecast for environmental compliance?

A. Yes. The PPLM license compliance personnel who provided the 2013 numbers have years of experience budgeting for license compliance expenses and actively managing the many hydro license compliance projects supported by these budgets. This is further supported by a budget-to-actual comparison; at year-end 2012 there was less than a 3.5% variance on a budget of over $4 million. NorthWestern's review of this data also supports these figures.

Q. Is the 2.5% escalator sufficient to cover the extended terms of the licenses?

A. Yes. The management framework to comply with environmental license conditions has built-in safeguards to reasonably control costs over the terms of the licenses. As described in Prefiled Direct Testimony of William T. Rhoads (pages WTR-37-41), PPLM has entered into Memorandums of Understanding ("MOUs"), programmatic agreements, and cooperative management agreements with state and federal resource agencies and other interested parties that set forth processes, establish technical

advisory committees, and define funding mechanisms to protect, maintain or enhance resources for the license terms at each of the four Federal Energy Regulatory Commission ("FERC") projects. These agreements and processes have been in place in most cases since the year 2000. They have stood the test of time and are the basis of the O&M forecast. Therefore, 2.5% is a sufficient escalator in this case for this issue.

Q. Please expand on the built-in safeguards mentioned above.

A. Two MOUs represent the majority of the O&M expense, cover nine of the 12 facilities, and address significant resources typically associated with hydroelectric facilities – fisheries, wildlife, water quality and recreation. The first one is the *Missouri-Madison Project 2188 Fisheries, Wildlife, Habitat, and Water Quality Protection, Mitigation, and Enhancement Memorandum of Understanding* (provided in response to Data Request PSC-033a). Parties to the MOU include the Montana Department of Fish, Wildlife and Parks ("MTFWP"), Montana Department of Environmental Quality ("MTDEQ"), U.S. Fish and Wildlife Service ("USFWS"), U.S. Forest Service ("USFS"), U.S. Bureau of Land Management ("BLM"), and the U.S Bureau of Reclamation ("BOR") (collectively referred to as "Resource Agencies"). The current MOU is for 10 years, through January 1, 2019. It requires that PPLM annually fund studies and PM&E measures to support license compliance. These PM&E measures are identified in FERC-approved resource plans developed via a Technical Advisory Committee

("TAC") made up of technical representatives of PPLM and the Resource Agencies. Exhibit B of the MOU, which identifies the required funding, is attached to this testimony as Exhibit__(MGS-1). These funding amounts were determined through a collaborative process with the Resource Agencies to implement the FERC-approved resource plan provisions. The MOU sets out the TAC's operating procedures, a process for prioritizing PM&E, and the administrative support PPLM must provide in this regard. In 2013, the annual funding was $1,241,790. Funds not spent in a particular year or funds provided by cost share partners (generally the Resource Agencies) are maintained in a "Capital Reserve Account" available to be spent during the term of the MOU. The TAC is active throughout the year and meets at least annually to develop annual work plans, prioritize PM&E measures, and manage expenditures.

The second MOU, which also includes safeguards to limit cost exposure, is the *Missouri-Madison Comprehensive Recreation Management Plan Amended and Restated Memorandum of Understanding ("Recreation MOU").* This MOU was established in 1999 and runs through the Project 2188 license term (2040). Parties include the USFS, BLM, MTFWP, USBOR and the six counties where the nine hydroelectric facilities are located; Madison, Gallatin, Broadwater, Chouteau, Lewis and Clark and Cascade. The Recreation MOU established Recreation Advisory Groups and Regional Working Groups and provides a mechanism for agencies,

the licensee, and the general public to work together to identify, prioritize and approve funding of recreation projects. A non-profit, independently operated Revolving Trust Fund ("Fund") was also established by a $5,000,000 contribution from PPLM and a matching amount contributed by the Resources Agencies or the public in the early 2000s to fund the acquisition, development and operation and maintenance of recreation opportunities in compliance with the FERC-approved *Comprehensive Recreation Plan*. NorthWestern's O&M forecast includes $500,000 for operation and maintenance of 32 recreation sites within the 2188 Project boundaries and to match a portion of the contributions to the Fund by parties to Recreation MOU up to the amount of annual investment earnings. The MOU includes restrictions on how, if, and when the Revolving Trust Fund's principle may be used. Agencies or other entities apply to use the Fund's monies for PM&E through a process established in the MOU.

Q. Upon transfer of the assets, will NorthWestern be responsible for these same matters?

A. Yes. NorthWestern will step into PPLM's shoes regarding these matters.

Q. Will the O&M forecast cover the cost of compliance if the Arctic grayling is listed under the Endangered Species Act ("ESA")?

1 **A.** Yes, to the extent the fishery studies and PM&E measures funded under
2 the *Missouri-Madison Project 2188 Fisheries, Wildlife, Habitat, and Water*
3 *Quality Protection, Mitigation, and Enhancement* MOU address Arctic
4 grayling or its habitat. However, NorthWestern does not know what
5 additional studies may be required, the timeline for these additional
6 studies, or potential mitigation strategies that might be required. Listing a
7 species under the ESA and implementing a recovery plan is a lengthy and
8 complex process. The USFWS published a notice in the Federal Register
9 in November 2013 that it was initiating a status review of the Arctic
10 grayling in the Upper Missouri River Basin. The notice indicated a
11 proposed rule or not-warranted finding would be published in the Federal
12 Register by September 2014. The public then has 60 days to comment on
13 the proposed rule. No more than a year from the deadline, the USFWS
14 must publish a final rule on the listing and within another year, designate
15 critical habitat for the Arctic grayling. If a decision is made to list the Arctic
16 grayling as threatened or endangered, the species receive legal protection
17 from adverse effects of qualifying federal activities. This would trigger
18 FERC's obligation to evaluate potential impacts from hydroelectric
19 developments on the Arctic grayling or its critical habitat. To this end and
20 based on the sequence of events that transpired when PPLM worked
21 through the bull trout listing at Thompson Falls, NorthWestern, as the
22 licensee, would request to be FERC's designee to prepare a Biological
23 Evaluation of effects based on necessary multi-seasonal studies and

1 submit the Evaluation to FERC and USFWS. NorthWestern (on FERC's
2 behalf) would then complete a Biological Assessment for the USFWS and
3 FERC, from which USFWS would conduct its own analysis to determine if
4 there are gaps in the information necessary to determine a project's
5 effects. This process could take several years and includes formal
6 consultation with numerous resources agencies, additional studies to fill in
7 data gaps, and scientific peer review of results. It culminates in a USFWS
8 Biological Opinion, which would include reasonable alternative actions
9 required of FERC (as regulator) and NorthWestern, as licensee, to
10 mitigate adverse impacts. All of these steps will take time. As a point of
11 reference for the timeline, the process for the Columbia River bull trout
12 took 12 years. The Columbia River population of bull trout, which includes
13 Thompson Falls, was listed as a threatened species under the ESA in
14 1998. It was not until 2010 that PPLM completed construction of the fish
15 ladder on Thompson Falls. The point is that the timeline or costs for
16 studies of Arctic grayling in the Upper Missouri River basin and mitigation
17 recovery measures that might be required are simply unknown. During
18 due diligence, a fish ladder for upstream passage of Arctic grayling was
19 considered at the Madison Development given PPLM's experience at
20 Thompson Falls. PPLM's 2008-2012 CapEx shows approximately
21 $8 million was spent over three years on the fish ladder at Thompson
22 Falls. However, we concluded that because of the much smaller
23 configuration of the Madison Dam, its low head, long apron, proximity to

solid substrate (which was a problem at Thompson Falls), it would be much cheaper, perhaps even a fraction of the cost, to install a fish ladder at Madison dam (if it is even warranted from a scientific or management perspective) than it was at Thompson Falls. For these reasons, and because of the uncertainty and the fact that expenditures would be over a number of years, an allowance was not made in the NorthWestern financial models to address a possible listing of Arctic grayling under the ESA.

Q. Does the O&M Forecast include the cost to relicense the Thompson Falls Project?

A. Yes. The cost of relicensing is not expected to materially change the O&M forecast. This is based on extensive PM&E to address bull trout and ongoing public recreation needs – including ongoing monitoring, operation of the fish passage facility, and agency involvement in the TAC since 2004.

Q. Does the O&M forecast include regulatory compliance costs if Kerr does not transfer to the Confederated Salish and Kootenai Tribes ("CSKT") in 2015?

A. No. In the event Kerr does not transfer, it is expected the Fish and Wildlife Implementation Strategy ("FWIS") payment to CSKT would need to

1 continue, which makes up the majority (96%) of the current compliance
2 expense.
3
4 **Q. How do you intend to pay for other environmental issues raised in**
5 **the due diligence, specifically potential Superfund issues at Black**
6 **Eagle and Thompson Falls and demolition of the old Rainbow**
7 **Powerhouse?**
8 **A.** Costs associated with potential Superfund issues at Black Eagle and
9 Thompson Falls are included in the O&M expense forecast on a line item
10 separate from the O&M described above. Costs associated with the
11 demolition of the old Rainbow Powerhouse are included in the CapEx
12 forecast (please see the responses to Data Requests PSC-031 and PSC-
13 080). A one-time allowance of $375,000 is included in 2025 for costs at
14 Black Eagle that might be associated with the Anaconda Copper Mining
15 Company ("ACM") Smelter and Refinery Superfund site. The Superfund
16 process includes identification of potentially responsible parties and
17 allocation of costs among the responsible parties. The amount of
18 NorthWestern's allocation was based on a best estimate by
19 NorthWestern's environmental team during Mustang I and was carried
20 forward in the financial models for Mustang II. The cost for remediation of
21 the Milltown Dam Superfund Site was used as a point of reference to
22 estimate a base case and high case considering the probability the
23 owner/operator of Black Eagle dam would be liable for remediation and if

so, the amount the owner might be allocated. The percentages are nominal for the reasons discussed below.

Milltown Reference	Probability of being named a PRP	Contribution Percentage	Contribution	
$100,000,000	0.3	0.050	$1,500,000	High Case
$100,000,000	0.15	0.025	$375,000	Base Case

It is unlikely that NorthWestern as the owner/operator of Black Eagle would be named a responsible party or that if it were, that the allocated portion of the cost to address contaminated sediments would be material because the vast majority of those expenses would be the obligation of the party who caused the pollutants. In addition, as is stated in response to Data Request MCC-067, if NorthWestern was named as a potentially liable party, it would have a strong case to shift the costs to the companies that owned and operated the facility from which the pollutants were released and/or that insurance may be available for such costs. Black Eagle is downstream from the former ACM facility; past mining activities at the ACM site are responsible for releases of hazardous substances at the site; and there is no evidence establishing that Black Eagle operations aggravate the contamination. Therefore, the geographic location of Black Eagle as well as the type and volume of hazardous substances released from the smelter activities form a reasonable basis for apportioning all Superfund (CERCLA) liability to ACM and its successors.

For Thompson Falls, an O&M allowance was made in NorthWestern's financial model of $187,500/year from 2021-2030 for monitoring reservoir sediments. The amount and timing was a best estimate by the NorthWestern environmental team during Mustang I and was carried forward to Mustang II. In the consent decree for the Milltown Dam and Reservoir Superfund Site, both the United States and the State of Montana provided a covenant not to sue for natural resource damages associated with the migration of contaminated sediments from Milltown to Thompson Falls and beyond.

A one-time sum of $1,000,000 was included in the CapEx forecast to address environmental issues associated with demolition of the old Rainbow Powerhouse. This would be in addition to monies realized from the scrap value of the equipment which are included in response to Data Request MCC-068. Further, in the Purchase and Sale Agreement, PPLM retained 50% of the liability for any above surface demolition costs in excess of $2,000,000 but equal to or less than $4,000,000 and 100% of the Rainbow Demolition Costs in excess of $4,000,000.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT "B"

Adaptive Management Fund Accounts*
PPL Montana 10 Year (year 2009-2018) Commitment

PPL Montana Steering Committee
(3.0 FTE)

-FERC licensing administration
-interagency TAC management
-PME compliance & implementation
-agency and NGO cost share programs

TAC Approved 2188 MOU funding 2009-2018
(2.5% increase in annual funding post 09)
New MOU TAC funding begins January 1, 2009

Project 2188 TAC	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Madison River Fisheries ($) (fund License Article 408, 409, 412 Plan)	325000	333125	341453	349989	358739	367708	376900	386323	395981	405880
Missouri River Fisheries ($) (fund License Article 414, 416, 417 Plan)	500000	512500	525313	538445	551906	565704	579847	594343	609201	624431
Madison-Missouri River Wildlife ($) (fund License Article 411, 418, 421, 423, 424 Plan)	300000	307500	315188	323067	331144	339422	347908	356606	365521	374659
Total Annual funding for 3 TACs ($) (promote cost sharing between TACs)	1125000	1153125	1181953	1211502	1241790	1272834	1304655	1337271	1370703	1404971
New MOU TAC Capital Account Maximums^										
Madison River Fisheries TAC ($)	100,000									
Missouri River Fisheries TAC ($)	100,000									
Madison-Missouri River Wildlife TAC ($)	200,000									

^Unspent TAC funds from prior year(s) and deposited funds from outside (non PPLM) agency or NGO cost share
*Adequate to fund PM&E measures per formal plans approved by agencies and the Commission. Water quality TAC annual funds to be determined annually by PPL Montana per Article 404 plan in consultation with agencies.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.12.85
PPLM Hydro Assets Purchase
NorthWestern Energy

PREFILED ADDITIONAL ISSUES TESTIMONY OF

GARY T. WISEMAN

ON BEHALF OF NORTHWESTERN ENERGY

Witness Information

Q. What is your name and occupation?

A. My name is Gary T. Wiseman. My business address is 9201 E. Dry Creek Road, Centennial, Colorado. I am Project Manager in Generation Services - Power for CB&I.

Q. Have you filed previous testimony in this docket?

A. No. However, as NorthWestern Energy's ("NorthWestern") primary independent due diligence engineering consultant on its proposed acquisition of PPL Montana, LLC's ("PPLM") hydroelectric projects, I provided the Shaw Independent Engineer's Final Report 01/03/13, the Addendum to Independent Engineer's Final Report (dated 06/25/2013), and the CBI Due Diligence Report Supplementing the 01/03/13 Report (dated 09/06/2013) included as Exhibit__(WTR-2.1), Exhibit__(WTR-2.2), and Exhibit__(WTR-2.3), respectively, to the Prefiled Direct Testimony of

William Rhoads ("Rhoads Direct Testimony") in this docket. I have also provided written responses to data requests.

Q. Please describe your educational and work background.

A. I graduated from Ohio State University in 1973. I have over 40 years experience in power engineering. My career has included over 34 years direct experience in the field of hydroelectric power and water resources. My career has been working with Stone & Webster Engineering Corporation, its successor Shaw Group, Inc., and its successor CB&I. I am a Professional Engineer. My assignments have covered an array of hydro projects including studies, design, construction, consulting, and due diligence efforts. My experience includes work on the following projects:

- Project Manager-Owners Engineer: NWE Aberdeen Unit 2 Generating Station

- Project Manager- Owners Engineer: NWE Dave Gates Generating Station

Due diligence for hydro plants or systems:

Northeast Generation

Boralex

Clean Power

Kaweah River Power Authority Project

STS Hydropower Projects

Friant Hydroelectric Project

Muck Valley Hydroelectric Project

Orion's Acquisition of Niagara Mohawk Hydro Assets

Endesa (Santander) Hydroelectric Assets

Orion's New York hydro assets

Bakun AC Hydro Power Project

Casecnan Multipurpose Project

Valerie Falls Hydroelectric Project

Tiber Dam Hydroelectric Project

Edelca's Tacoma Hydroelectric Project

Design for hydro plants:

Thompson Falls Hydroelectric Project- Second Powerhouse

Rock Island Second Powerhouse

Rocky Reach- turbine rehab

Konaktepe Hydroelectric Project

Victoria Dam

Tazimina River Hydroelectric Project

A summary of my experience is provided as part of Exhibit__(WTR-1) accompanying the Rhoads Direct Testimony.

Purpose of Testimony

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

1 **A.** I am testifying in response to additional issues identified by the Montana
2 Public Service Commission ("Commission") in its April 4, 2014 Notice of
3 Additional Issues ("Notice") and to the information provided to the
4 Commission by The Essex Partnership ("Essex"), its engineering
5 consultant, in a checklist provided on March 31, 2014 ("Checklist") and a
6 memorandum provided on April 2, 2014 ("Memo"). My testimony
7 addresses the Essex Memo and Checklist and the Commission's requests
8 and concerns regarding civil items, sufficiency of the due diligence effort,
9 and capital expenditure forecast.
10
11 **Q. What is the basis of your testimony?**
12 **A.** The basis of my testimony is my personal involvement as Project Manager
13 responsible for CB&I's due diligence effort to assist in the evaluation of
14 NorthWestern's acquisition of the hydro assets. This effort has been
15 ongoing since the fall of 2012. I have been directly involved in the due
16 diligence process, including review of materials contained in the PPLM
17 data room, information in the public domain, personal discussions with
18 PPL and PPLM management personnel, and site visits. CB&I's due
19 diligence effort paralleled that of NorthWestern's. CB&I's due diligence
20 effort focused on the condition of assets, Capital Expenditure ("CapEx")
21 and Operations and Maintenance ("O&M") costs, license compliance, and
22 environmental aspects.
23

Essex Memo and Checklist

Q. What is your assessment of the Essex Memo and Checklist?

A. The Essex Memo and Checklist contain observations and conclusions in the areas of civil, equipment, environmental liabilities, regulatory compliance, and NorthWestern's projected capital expenditures. As stated above, I will address the issues related to civil aspects.

The Checklist provides generalized observations about the system's civil aspects. Some conclusions are incorrectly applied widely to each of the developments. This may be the result of the lack of opportunity to conduct the same level of due diligence that NorthWestern and CB&I were able to conduct, including assessing all available information to understand the pertinent details of each of the individual developments. In addition, Essex draws generalized conclusions about some aspects and broadly labels certain approaches or remedies to items as "industry practice" when in fact the most effective arrangement depends on specific development arrangements, system (not item) consideration, and history of maintenance and rehabilitation.

Q. Please summarize the additional information regarding the items Essex identified in the civil category.

A. Essex identified three civil items of concern in its Memo that in its opinion could, for the implementation of the potential remedy, have a potential

future significant cost. These three civil items are 1) flashboard-stanchion systems on spillway crests, 2) status of post-tensioned rock anchors in structures, and 3) potential rockfall impact on conveyances

NorthWestern considered these items in its due diligence review and provides this additional information to confirm that the hydro system facilities and structures are in satisfactory condition and are appropriately monitored and evaluated on a routine basis; that the civil items of concern are not as significant as implied or characterized in the Essex Checklist; and that the considered items of concern and associated remedies and their potential costs are of a very low probability of occurrence.

Q. Essex commented extensively in its Memo and Checklist on the existing and future use of flashboard-stanchion systems at spillways. Please address these comments.

A. Flashboards are boards or panels on the crest of a spillway. They are provided to increase the normal reservoir level and to provide control of high water discharges by select removal or by tripping to release a section. Stanchions support the flashboards on the crest and provide a mechanism to trip and release a flashboard section as needed in flood conditions. Flashboard systems are an effective means to maintain normal operational reservoir water level and still have the capability for high discharge flows in the event of low probability extreme flooding.

Flashboard/stanchion systems should be evaluated in the context of the plant physical layout and the overall equipment and means available to control water flow releases, not in isolation. It is a far reaching assertion by Essex to suggest replacing viable flashboards with gates or rubber dams. Replacement would require incurring significant cost that at this time is difficult to justify.

Flashboards are actually tripped and used only on the very infrequent occurrence of high flood flows, after the discharge capacity of other gates, panels, or rubber dams of a given development is exceeded. Reliability of flashboards is considered acceptable and effective in this context. They are available and functional when needed in an extreme event. There are standard operating procedures for gate and flashboard operations; the plant operators are trained, and dry testing has proved the acceptable operation of the stanchion release mechanism. Concerns about deterioration or damage to flashboards are not unlike similar considerations for gates or other systems. There can be numerous panels or logs to remove to provide needed water discharge. This can and has been effectively done with reasonable lead-time from operations/flow forecasting. The hydro system plants are on well-regulated rivers. Hebgen and Canyon Ferry on the Missouri River system and Flathead Lake on the Clark Fork system provide upstream storage and system flow regulation. Reservoir lowering is not necessarily needed to reinstall

tripped, lost, or damaged flashboard system components. An available bulkhead allows maintenance or repairs without reservoir lowering. Debris inflow is usually not a significant issue at the hydro system developments, except in the spring at Thompson Falls where radial gates are effective to pass debris. Leaking and spilling flashboards do not affect condition inspection of downstream facilities any more than leaking and spilling gates might.

The Black Eagle development is an example of an acceptable and effective flashboard system. The Black Eagle waste gate structure provides the initial capability to discharge water and has eight 10.25 feet wide by 9.75 feet high hydraulically operated steel sluice gates. The 25 flashboard bays are each 25 feet wide. Flashboard panels are 10 feet high by 5 feet wide (5 panels per bay). To provide flow discharge capacity, the boards of the flashboard panels can be removed one at a time using a hoist that travels the length of the spillway, or all of the boards in a panel can be released by manually tripping the stanchions. A standard operating procedure is established for the tripping operation, and operators receive annual training using a dry-land full scale mock-up of the stanchion tripping mechanism. A de-icing bubbler system is installed in the winter to protect against ice load damage.

Based on the above considerations, there is a very limited potential to incur significant cost to replace existing flashboard-stanchion systems. Accordingly, no specific line-item significant cost is included in the 20-year projection. We expect that future costs related to flashboard-stanchion systems will be covered in the projected O&M budget.

Q. Essex commented extensively in its Memo and Checklist on the status of existing structural rock anchors and the potential need to install updated anchors. Essex is concerned about deterioration of anchors resulting from potential corrosion or potential anchor relaxation. Please address these comments.

A. Rock anchors are used to provide stability load to structures to resist extreme external loading conditions. The anchors are tensioned or stressed to induce the stabilizing force into the structure. Essex's concern is the potential for corrosion to deteriorate an anchor and possibly have some loss of that stabilizing capability. Essex's other concern is the possibility that over time an anchor may to a limited extent physically relax (lose some of its tensioning) and lose some stabilizing capability. Rock anchor corrosion or anchor relaxation each have a very low probability of occurrence to the extent that they impact structural stability. Essex suggests that there is the potential need to reinstall rock anchors with double corrosion protection on the basis of these considerations. There is no reason to incur the significant cost to do so.

Furthermore, I must emphasize that consideration of deterioration of anchors impacting structural stability is in the context of addressing rigorous safety criteria for extreme events of very low probability of occurrence: Potential Failure Modes ("PFM") and earthquake loadings. In the hydro system, no anchors are installed for stability for normal loading conditions. This concern regarding adequacy of anchors applies to a very remote scenario concerning anchor status and extreme loading conditions.

I agree with Essex that anchors with double corrosion protection are today's standard practice. The anchors from an earlier time are corrosion protected. They are just not double protected. This means that the existing anchor protection scheme very slightly increases the already very low possibility of impact to the effectiveness of a given anchor. Anchors with a single corrosion protection design are viable and effective in providing the loading intended to provide structural stability. Furthermore, corrosion impact would be on an isolated singular anchor; damaging deterioration to multiple anchors is unlikely. There would be no catastrophic failure of anchors endangering a structure. Also, structures in the hydro system are of ample design as indicated by the fact that they were in place and serviceable for a long time prior to installation of the anchors.

Relaxation of anchors and the resulting potential for reduced effectiveness of anchors is an item recognized in the industry. It is considered in design and is usually of limited extent. Accordingly, routine and frequent surveillance and monitoring of a structure includes vertical and horizontal alignment surveys, monitoring piezometers for foundation pressure, monitoring drain flows for foundation conditions, and regular and documented visual surveillance of the structure. All contribute to regular and timely understanding of the status of the structure and, as may be pertinent and contributory, the condition of the anchors. Thus, regular monitoring and assessment of a structure and its associated anchors avoids deterioration to the point of impacting structural stability. This monitoring and assessment is a full and formal process performed to Federal Energy Regulatory Commission ("FERC") requirements and reviewed by FERC.

Black Eagle is an example of a plant having an effective existing anchor arrangement. Nine post-tensioned anchors are installed in the piers of the wastegate structure at Black Eagle. The anchors extend a minimum of 18 feet into the foundation rock. PFM 5 -- Overturning/ sliding failure of the waste gate section from unusual loading (seismic, ice, PMF) causing release of reservoir -- is Category IV, Ruled Out, per the 2009 Part 12 report. Foundation piezometric readings are acceptable, indicating satisfactory status of the structure.

The subject of rock anchors is specifically addressed for each of the pertinent developments in NorthWestern's detailed response to the Essex Checklist, provided as Exhibit__(WTR-10) accompanying the Prefiled Additional Issues Testimony of William T. Rhoads.

Based on the above considerations, there is a very limited potential to incur significant cost to replace existing post-tensioned rock anchors. Accordingly, no specific line-item significant cost is included in the 20-year CapEx projection. We expect that future costs related to rock anchors and related stability considerations will be covered in the projected O&M budget.

Q. Essex commented in the Memo and Checklist on potential rock fall damaging flowlines. Please address these comments.

A. Rock falls are reportedly infrequent. The Essex comments are directed to two pertinent developments: Madison and Mystic. At Mystic the flowline is on an excavated shelf on a high rocky slope. Potential failure of the flowline has minimum impact on public safety since the hiking trail is on the opposite side of the valley, above water flow level. The headgate at the upstream end of the flowline automatically closes, if needed, based on differential pressure, to limit water release and downstream impacts. Some rock scaling or installation of shields or covers at select locations and/or discrete flowline repairs can be implemented if needed in the

normal course of business under the projected O&M budget. Accordingly, no specific line-item significant cost pertaining to potential rock falls is included in the 20-year CapEx projection.

Commission-Requested Information

Q. The Commission requested additional information on due diligence issues, specifically structural integrity, and on the adequacy of NorthWestern's due diligence effort. Please address these items.

A. CB&I's previous findings in our Independent Engineer due diligence reporting were that the hydro system structures and facilities are in satisfactory condition. The ongoing program of upgrades and rehabilitation appears effective to maintain reliable operation. After reviewing the civil items identified by Essex, CB&I reiterates its initial position and understanding. The civil items are flashboards, anchors, rock falls, stability, and concrete deterioration. We addressed each item for each development in our detailed response to the Essex Checklist. Based on our consideration of these items, there is limited potential for additional significant cost going forward that is not a specific project with an identified line-item budget or covered by the projected overall budgets.

Indeed, as the due diligence process continues to progress and PPLM continues system programs, NorthWestern staff and I learn more that bolsters our understanding that the system facilities are in satisfactory

condition. As an example, PPLM has recently documented the completed analysis and satisfactory stability of Kerr dam for updated seismic load criteria (April 2014). This is another point to the adequacy of the hydro system.

Based on my experience in the hydro industry, including work on other various due diligence efforts, NorthWestern's due diligence effort for the hydro system is appropriate and fully sufficient. Material items and aspects were properly considered. This is also addressed by HDR Engineering, Inc. in separate testimony.

Q. The Commission requested additional information regarding projections of future costs. Please explain NorthWestern's cost projections.

A. The Prefiled Additional Issues Testimony of Joseph Stimatz presents information showing that even an extensive increase in future CapEx forecast costs would have limited impact on NorthWestern's electric portfolio cost. As discussed above, I do not expect that magnitude of future additional costs. The current CapEx and O&M budget projections are valid and appropriate.

Q. Does this conclude your testimony?

A. Yes, it does.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.12.85
PPLM Hydro Assets Purchase
NorthWestern Energy

PREFILED ADDITIONAL ISSUES TESTIMONY OF

RICK MILLER, P.E.

ON BEHALF OF NORTHWESTERN ENERGY

Exhibits

HDR Engineering, Inc. Policy Opinion Letter and supporting documentation	Exhibit__(RM-1) *(provided on CD)*

Witness Information

Q. What is your name, occupation, and business address?

A. My name is Rick Miller. I am a Registered Professional Engineer and the Senior Vice President for Hydropower Services at HDR Engineering, Inc. My business address is 440 S. Church Street, Charlotte, North Carolina.

Q. Please describe your educational and work background.

A. I earned my Bachelor of Science degree in Civil Engineering in 1978 from Auburn University and began my hydropower career at Duke Energy. While working full time, I earned my Master of Engineering degree in Civil Engineering with an emphasis on geotechnical engineering in 1983 from the University of South Carolina. My career with Duke Energy began in the civil engineering support group for all of Duke Energy's fossil and

hydropower assets in the Carolinas. Duke Energy's hydropower fleet was at the time, and still, is the second largest privately owned hydropower fleet in the United States. Of the 31 hydropower stations Duke owned at that time, all but three were built prior to 1928, so the civil engineering team developed significant experience with older vintage hydropower assets. I progressed in my career to become Duke Energy's first Hydro System Engineer where I was responsible for all capital project planning and execution, dam safety oversight and emergency action plan implementation, outage coordination, and fleet-wide maintenance strategies.

In 1988 I moved into an operations role where I was the regional manager for six existing (and generally very old and very small) hydropower stations plus one very large pumped storage project under construction. After the completion of the $1 billion Bad Creek pumped storage project, where I led the commissioning team, I returned to the General Office to begin the effort to modernize Duke Energy's hydropower fleet. Beginning in 1993, Duke began a 15-year modernization program of investing in turbines, generators and the balance of plant systems. At the peak of its implementation, it was reported to be the largest modernization program underway in North America based upon equipment orders placed with the turbine vendors. I was the Program Manager for the first seven years of the modernization program, from 1993 to 1999, when we established the

goals and objectives of the program, a standardized approach to station modernization and procurement and contracting strategies, in addition to executing the engineering and outage work for the first series of stations. During this program, the hydropower engineering group I was managing was transferred to Duke Energy's consulting services company, Duke Engineering & Services.

In 1999, I directed the due diligence efforts, and then led the transformation team, of a 2300-MW hydropower acquisition in Brazil under Duke Energy's ownership. I moved to Brazil where I was the Director of Operations for all of the assets owned by Duke Energy in Brazil, including the station Operations & Maintenance ("O&M") staff, the engineering staff, system operations, health and safety, and the environmental/fishery staff.

In 2003, after returning from Brazil, I left Duke Energy to help form a hydropower consulting services company called Devine Tarbell & Associates. We went into business on July 1, 2003 with six offices in the U.S. and 120 employees. I was the Chief Operating Officer responsible for the execution and Quality Assurance of all of the work products completed by my staff. In 2006 I became CEO with more of an external focus on the future of the hydropower industry. At approximately this same time I began my industry service on the Board of the National Hydropower Association ("NHA") and was elected President of NHA from

2008 to 2009 and provided support to the U.S. Department of Energy, the Federal Energy Regulatory Commission ("FERC"), and Congressional leaders on grid operations and hydropower's role in sound energy policy.

I currently lead the Hydropower and Energy Storage Services group at HDR Engineering, Inc., which acquired my firm, Devine Tarbell & Associates, in January 2009.

Q. Please describe HDR Engineering, Inc.

A. HDR Engineering, Inc. ("HDR") is an employee-owned firm with headquarters in Nebraska. The hydropower services team comprises over 250 engineers, scientists, and regulatory specialists in 10 offices around North America and is built upon our foundational belief that every non-federal hydropower client will need each of those disciplines in the life cycle of hydropower asset ownership.

The HDR hydropower team has an extensive history of providing efficient and competent due diligence assessments of hydroelectric assets ranging from storage reservoirs and conventional run-of-river facilities to store-and-release and pumped storage facilities. Staff at HDR has evaluated over 300 generating stations in over 20 countries, including the United States, Canada, China and Brazil, representing more than 54,000 MW of hydroelectric capacity. HDR personnel have extensive due diligence

experience for both public and private sector clients, including traditional utility owners, independent power producers, technical and business consultants, international lending institutions, government agencies, and merger and acquisition advisors for both merchant facilities and those supported by purchase power agreements.

Purpose of Testimony

Q. What is the purpose of this testimony?

A. I am testifying in response to additional issues raised by the Montana Public Service Commission ("Commission") in its April 4, 2014 Notice of Additional Issues ("Notice). In its Notice, the Commission requested 1) additional information regarding "the structural integrity, physical condition, environmental liabilities, and the sufficiency of NorthWestern's due diligence effort for each of the individual facilities" and 2) information that will provide "a fuller understanding of what the range of potential future CapEx and O&M costs might be and the effect of those potential costs on NorthWestern's net present value cost estimates." I address the Commission's requests and concerns.

Q. Please describe HDR's role relative to NorthWestern Energy's ("NorthWestern") acquisition of the Hydros.

A. NorthWestern retained HDR to provide consulting services in the areas of hydropower engineering, operations, maintenance, and dam safety related

to NorthWestern's acquisition of the PPL Montana, LLC ("PPLM") hydropower assets (the "Hydros"). HDR reviewed the following Shaw/CB&I due diligence documents:

- Independent Engineer's Report dated 01/03/2013 (Exhibit__(WTR-2.1)), attached to the Prefiled Direct Testimony of William Rhoads;
- Addendum to Engineer's Report dated 06/25/2013 (Exhibit__(WTR-2.2)); and
- Due Diligence Report supplementing Independent Engineer's report dated 09/06/2013 (Exhibit__(WTR-2.3)).

HDR also interviewed selected NorthWestern staff with extensive knowledge of the PPLM hydroelectric assets during the period of February through April 2014 regarding the age and condition of assets, the historical maintenance and capital investment activities, and the future need for capital and expense expenditures. HDR developed its independent opinion regarding the sufficiency of the due diligence effort conducted by NorthWestern including its assessment of the structural integrity, physical condition, and environmental liabilities of the individual facilities. In addition, HDR independently developed a 20-year capital expenditure ("CapEx") forecast and compared its forecast to NorthWestern's forecast in Exhibit__(JMS-1), attached to the Prefiled Direct Testimony of Joseph Stimatz.

Q. What is HDR's opinion about the sufficiency of NorthWestern's due diligence effort for each of the facilities?

1 **A.** It is HDR's opinion that the due diligence report and its supplements
2 provide sufficient detail for the material issues related to the each of the
3 individual assets. The due diligence report identifies that each of the
4 facilities was visited, the current condition assessment was documented,
5 the available dam safety and environmental compliance related
6 documents were reviewed, and the historical capital and O&M
7 expenditures were assessed in view of the age and condition of the assets
8 and the projected investments going forward.
9
10 The dam safety document review included the available FERC
11 Independent Consultant dam safety inspections plus the remediation
12 plans completed, currently underway, and required to be implemented up
13 through 2017.
14
15 Additionally, the extensive PPLM environmental and license compliance
16 record was reviewed in the due diligence and its supplemental reports.
17 The robust FERC license compliance record is reflected in the historical
18 costs.
19
20 **Q. What is HDR's 20-year forecast of capital investments?**
21 **A.** HDR independently developed a 20-year forecast of capital investments
22 that incorporated the information provided in the Shaw/CB&I due diligence
23 reports and the interviews with NorthWestern staff with knowledge of the

facilities and their condition. The HDR forecast accounts for the age of the components, the history of investments, and the operating environment of the assets, to the degree possible utilizing the standard of care for professional engineering, consulting, and related services ordinarily used by members of hydropower engineering profession.

It is HDR's opinion that NorthWestern's due diligence accurately documents the actual PPLM hydropower modernization program to date and the planned expenditures out to 2017. The already implemented and the planned investments are consistent with HDR's experience for the level of expenditure generally required to maintain similar hydropower assets in reliable operating condition.

HDR's independent capital investment forecast, which varies year by year based upon the reported historical and planned capital expenditures (and the time available to complete this independent review), recommends an average annual budget of $7.1 million (in 2014 dollars).

The HDR 20-year forecast includes both specific CapEx projects such as anticipated remaining generator rewinds and turbine overhauls and an unspecified allocation of CapEx investments for each station for each year. In developing its 20-year capital investment forecast, HDR confirmed that the majority of recommended capital investment for a

hydropower fleet of this vintage was undertaken prior to 2014, with the completion of the balance of plant systems at each of the stations and the critical units' turbines and generators.

Q. What is HDR's opinion about NorthWestern's CapEx forecast?

A. HDR's analysis confirms that NorthWestern's projected CapEx estimates are sufficient to account for the known liabilities at this time. HDR did not identify any required Part 12 Independent Consultant recommendations that were not included in the forecasted capital expenditures. Projected capital expenditures and O&M cost estimates for known compliance requirements have been included.

HDR's review of NorthWestern's 20-year CapEx forecast (Exhibit__(JMS-1)) concludes that it incorporates targeted investments for specific needs identified at this time that have not been addressed by planned investments prior to 2018. HDR concurs with NorthWestern's assertion that the majority of the hydro fleet-wide modernization program has been completed, and those historical higher levels of CapEx investments are not required beyond 2017.

HDR's recommended average CapEx budget of $7.1 million per year (in 2014 dollars) compares favorably to NorthWestern's projected $8.5 million per year of capital expense to safely operate and maintain the hydropower

assets and in our opinion confirms the adequacy and sufficiency of NorthWestern's due diligence.

Q. What is HDR's assessment of the physical and structural condition of the Civil Elements and Water Retaining Structures?

A. For decades the FERC has required that each licensee facilitate a thorough dam safety inspection by an Independent Consultant once every five years. These inspections are known as Part 12 inspections and their purpose is to identify any actual or potential deficiencies, whether in the condition of the project's works or in the quality or adequacy of project maintenance, surveillance, or methods of operation that might endanger public safety. These independent inspections and record review are performed in compliance with the FERC's established dam safety criteria in place at that time. The licensee is required to address all recommendations made by the Part 12 Independent Consultant.

The hydropower industry, at the direction of the FERC, incorporated the Probable Failure Modes Analysis ("PFMA") process in 2004. This created a rigorous and defined methodology where a team of dam safety experts independently assess the condition of the facilities and identify possible failure modes, their likelihood of occurrence, and potential risk reduction measures. The identification and development of Potential Failure Modes under the FERC process is not an indication of a fundamental flaw or

deficiency that requires remedial action or planned future investments. If modifications for dam safety were required they would be clearly identified and acted on at the time of the PFMA. The owner's dam safety program should be well aligned with the identified Potential Failure Modes to assure that the appropriate actions such as surveillance and monitoring are being taken so that the initiation or progression of a failure mode would be identified to allow for successful intervention and action. This state-of-the-practice process is documented in the due diligence report, and facility-specific issues are addressed by the PFMA process. Each licensee is accountable to the FERC to implement the required actions resulting from that process and all recommendations made by the Part 12 Independent Consultant. The Shaw/CB&I final due diligence report has identified the actions PPLM has undertaken, and is planning to undertake, to comply with all dam safety requirements. In particular, the routine assessment of post-tensioned rock anchors is conducted, and re-analysis is performed should post tensioning relaxation be identified during the five-year Part 12 Independent Consultant inspections.

HDR's review of the due diligence report confirms that there are no current recommendations for the installation of additional post-tensioned rock anchors, nor should there be based on our review of the record on this matter. Should future testing indicate the occurrence of post tension relaxation or find evidence of tendon corrosion, then additional dam

stability re-analysis would be performed and the most effective solution identified which then must be approved by the FERC. This is a business risk issue, and in the absence of a defined, specific recommendation it is not HDR's experience to include in future expense forecasts the costs of additional post-tensioned rock anchors as a contingency for non-specific unidentified anchor performance concerns.

HDR's review of the due diligence report and the Part 12 Independent Consultant Inspection reports confirms there are no current recommendations for replacing or modifying the remaining flashboard-stanchion systems or any of the other flashboard operating systems at the Hydros that would affect the CapEx investment projected beyond 2017. As demonstrated by decades of acceptable service, these systems have functioned safely and are a proven, low technology method accepted by the FERC. HDR's experience is that similar systems remain in service at many facilities in the United States and Canada. This is especially true where the number of annual operation cycles is low, which is the case with the PPLM facilities.

Several of the replacement options identified in the Essex report have previously been implemented by PPLM where it made good engineering sense, and public safety sense, to do so. There is no evidence to support

the concerns identified in the Essex memo that the existing systems create the potential to incur significant capital investment.

Q. What is HDR's assessment of the condition of the Mechanical and Electrical Systems?

A. The Shaw/CB&I due diligence reports document the extensive historical prime mover and related mechanical and electrical capital investments implemented by PPLM during its ownership of the assets. Hydropower assets are long-lived assets that, after the initial capital expense of construction, require minimal, but routine, investment over time to maintain their reliability and functionality. Much like other large capital infrastructure projects such as roads, bridges, and water supply systems, there does come a time when a more extensive rehabilitation is required to assure the reliability and functionality of the components for additional life-cycle capability.

The age of the assets led PPLM to invest significantly in the hydropower stations that were most critical to the portfolio. PPLM's modernization plan that was documented in the Shaw/CB&I due diligence report and its supplemental reports demonstrated that the fleet-wide investment is anticipated to be substantially complete by 2017. The interviews with the NorthWestern staff confirmed that future investments in the remaining units that were not modernized by PPLM, including Black Eagle, Hauser,

Holter, Madison, and Thompson Falls, are accounted for in NorthWestern's 20-year capital expense forecast.

Developing a fleet-wide modernization program to the extent done by PPLM must take into account numerous elements such as unit generating history in terms of capacity factor and its cycle duty, local staff knowledge of the uniqueness of each unit for items such as runner cavitation repairs or generator rewedging, and the basic requirements of reliably providing generation and safely moving water through the river system cascade. Unlike other forms of electrical generation, owners of hydropower stations must be cognizant of passing flow from the individual facilities to meet downstream water quality requirements and managing flood flows, independent of electrical grid needs. This means that hydropower owners must incorporate into their long-term plans the ability to sequence outages in a manner that supports the ability to safely implement water management requirements of the river system. This also means that it is incumbent on a hydropower owner to implement a broad enough scope of turbine overhauls and generator rewinds to address any known issues that would affect that future reliability and the ability to safely move water. For example, if the components of the generator such as the rotor spider had evidence of cracking or fatigue, it would typically manifest in chronic vibration or out of roundness that would affect unit operations and future reliability. If there were known equipment reliability concerns that remain

to be addressed beyond what PPLM has planned, NorthWestern staff's intimate knowledge of the assets has accounted for that projected work scope in the 20-year forecast of capital expenditures.

The Essex Partnership's Checklist and Memorandum offer without evidence the notion that due to age, metal fatigue can cause cracking in the rotor components and ultimately lead to a catastrophic failure, and that replacing the rotor components is a potential remedy. While this may be hypothetically true, due to the robustness of the actual design of these vintage units, it has not been HDR's experience that the rotor structural component replacements are required after 80 or 100-plus years of service. Certainly the electrical elements such as the windings and rotor poles do require periodic refurbishment and that is entirely the point of performing a generator rewind. HDR's experience indicates this is also true of the turbines where the embedded structural elements are robust and rarely require replacement, but the rotating elements also require rehabilitation after a period of years of reliable operations.

HDR's opinion is that the documented investments in the electrical and mechanical components of the hydropower fleet have been implemented in a planned and comprehensive manner to assure future reliable operations of the system. HDR's review of NorthWestern's 20-year CapEx forecast indicates the components at Black Eagle, Hauser, Holter,

Madison and Thompson Falls and facility components at other stations of the fleet that are anticipated to not be completed by 2017 have been accounted for.

Q. What is HDR's assessment of the Environmental and Regulatory Compliance?

A. The extensive record of license compliance was documented in the due diligence report and its supplements, and the supporting memo from Skadden, Arps, Slate, Meagher & Flom LLP for the four FERC licenses that comprise the fleet of assets including the Missouri-Madison Project, the Thompson Falls Project, the Kerr Project, and the Mystic Lake Project. With the issuance of the FERC license for the Missouri-Madison Project in 2000, a significant capital investment program was required. The due diligence report and its supplements document the rigorous history of compliance, known future compliance requirements, and the staffing that is in place to continue to monitor and implement future compliance requirements.

It is HDR's opinion that NorthWestern has sufficiently accounted for the known environmental and regulatory requirements of the hydropower assets. The historical capital expenditures for license compliance, once complete, allow the facilities to remain in compliance. HDR's experience

is that the long record of O&M costs, once the capital investment is complete, are a good predictor of future O&M expenditures.

Q. In your testimony, you refer to HDR's opinion. Has HDR formally issued any documents reflecting its opinions?

A. Yes. On April 17, 2014, HDR delivered an Opinion Letter to Mr. William Rhoads of NorthWestern. The Opinion Letter, which includes HDR's independent capital investment forecast, is the basis for my testimony. A copy of the Opinion Letter and supporting documentation is provided on CD as Exhibit__(RM-1).

Q. Does this conclude your testimony?

A. Yes it does.

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.12.85
PPLM Hydro Assets Purchase
NorthWestern Energy

PREFILED ADDITIONAL ISSUES TESTIMONY OF

TRAVIS E. MEYER

ON BEHALF OF NORTHWESTERN ENERGY

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Exhibits

LT Rev Req Model (Plus 30% capital expenditures)	Exhibit__(TEM-3)
LT Rev Req Model (Minus 15% capital expenditures)	Exhibit__(TEM-4)

Witness Information

Q. Please state your name and business address.

A. My name is Travis E. Meyer. My business address is 3010 West 69th Street, Sioux Falls, South Dakota 57108.

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

A. I am employed by NorthWestern Energy ("NorthWestern") as the Director of Investor Relations and Corporate Planning. In my Investor Relations role, I am largely responsible for communicating the strategic direction of NorthWestern to its equity investor community within the confines of Regulation Fair Disclosure. My Corporate Planning duties include oversight of the five-year financial planning model and related analysis as well as analysis and evaluation of certain projects on a case-by-case basis.

Q. Are you the same Travis Meyer who submitted prefiled direct testimony in this docket?

A. Yes.

Purpose of Testimony

Q. What is the purpose of this testimony?

A. The Montana Public Service Commission's ("Commission") April 4 Notice of Additional Issues directed NorthWestern to provide testimony on,

among other things, the effect that additional capital expenditures ("CapEx") would have on the net present value ("NPV") of the costs of the supply portfolio. This testimony explains the changes made to Exhibit__(TEM-2) which was included with my prefiled direct testimony to evaluate the impacts that increased and decreased levels of annual CapEx would have on the annual revenue requirement in the LT Rev Req Model.

Scenarios Considered and Additional Exhibits

Q. Are you submitting a revised LT Rev Req Model with your testimony that demonstrates these increased and decreased CapEx scenarios?

A. Yes, they are attached as Exhibit__(TEM-3) and Exhibit__(TEM-4).

Q. Specifically, what changes were made to Exhibit__(TEM-2) to produce Exhibit__(TEM-3) used to evaluate the increased CapEx scenario?

A. The CapEx in Exhibit__(TEM-3) exceeds the CapEx in Exhibit__(TEM-2) by 30% each year. The Prefiled Additional Issues Testimony of John VanDaveer ("VanDaveer Additional Issues Testimony") explains the rationale for using this contingency amount. The table that follows illustrates the annual CapEx included in Exhibit__(TEM-2), the 30% contingency CapEx, and the revised total annual CapEx as included in Exhibit__(TEM-3).

	($Thousands)				
Year	Exhibit (TEM-2) CapEx	+	Plus 30% Contingency	=	Exhibit (TEM-3) CapEx
2014	$ 12,831		3,849		$ 16,680
2015	$ 9,964		2,989		$ 12,953
2016	$ 9,195		2,758		$ 11,953
2017	$ 11,991		3,597		$ 15,589
2018	$ 8,500		2,550		$ 11,050
2019	$ 8,713		2,614		$ 11,326
2020	$ 8,930		2,679		$ 11,610
2021	$ 9,154		2,746		$ 11,900
2022	$ 9,382		2,815		$ 12,197
2023	$ 9,617		2,885		$ 12,502
2024	$ 9,875		2,962		$ 12,837
2025	$ 10,104		3,031		$ 13,135
2026	$ 10,365		3,110		$ 13,475
2027	$ 10,615		3,185		$ 13,800
2028	$ 10,881		3,264		$ 14,145
2029	$ 11,171		3,351		$ 14,522
2030	$ 11,432		3,430		$ 14,861
2031	$ 11,717		3,515		$ 15,233
2032	$ 12,010		3,603		$ 15,613
2033	$ 12,310		3,693		$ 16,004
2034	$ 12,618		3,785		$ 16,404
2035	$ 12,934		3,880		$ 16,814
2036	$ 13,257		3,977		$ 17,234
2037	$ 13,588		4,077		$ 17,665
2038	$ 13,928		4,178		$ 18,107
2039	$ 14,276		4,283		$ 18,559
2040	$ 14,633		4,390		$ 19,023
2041	$ 14,999		4,500		$ 19,499
2042	$ 15,374		4,612		$ 19,986
2043	$ 15,758		4,728		$ 20,486

Q. Specifically, what changes were made to Exhibit__(TEM-2) to produce Exhibit__(TEM-4) used to evaluate the reduced CapEx scenario?

A. The CapEx in Exhibit__(TEM-4) is less than the CapEx in Exhibit__(TEM-2) by 15% each year. The VanDaveer Prefiled Additional Issues Testimony explains the rationale for using this contingency amount. The table that follows illustrates the annual CapEx included in Exhibit__(TEM-2), the 15% reduction in CapEx, and the revised total annual CapEx as included in Exhibit__(TEM-4).

	($Thousands)				
Year	Exhibit (TEM-2) CapEx	-	Minus 15% Contingency	=	Exhibit (TEM-4) CapEx
2014	$ 12,831		(1,925)		$ 10,906
2015	$ 9,964		(1,495)		$ 8,470
2016	$ 9,195		(1,379)		$ 7,816
2017	$ 11,991		(1,799)		$ 10,193
2018	$ 8,500		(1,275)		$ 7,225
2019	$ 8,713		(1,307)		$ 7,406
2020	$ 8,930		(1,340)		$ 7,591
2021	$ 9,154		(1,373)		$ 7,780
2022	$ 9,382		(1,407)		$ 7,975
2023	$ 9,617		(1,443)		$ 8,174
2024	$ 9,875		(1,481)		$ 8,393
2025	$ 10,104		(1,516)		$ 8,588
2026	$ 10,365		(1,555)		$ 8,811
2027	$ 10,615		(1,592)		$ 9,023
2028	$ 10,881		(1,632)		$ 9,249
2029	$ 11,171		(1,676)		$ 9,495
2030	$ 11,432		(1,715)		$ 9,717
2031	$ 11,717		(1,758)		$ 9,960
2032	$ 12,010		(1,802)		$ 10,209
2033	$ 12,310		(1,847)		$ 10,464
2034	$ 12,618		(1,893)		$ 10,725
2035	$ 12,934		(1,940)		$ 10,994
2036	$ 13,257		(1,989)		$ 11,268
2037	$ 13,588		(2,038)		$ 11,550
2038	$ 13,928		(2,089)		$ 11,839
2039	$ 14,276		(2,141)		$ 12,135
2040	$ 14,633		(2,195)		$ 12,438
2041	$ 14,999		(2,250)		$ 12,749
2042	$ 15,374		(2,306)		$ 13,068
2043	$ 15,758		(2,364)		$ 13,395

Q. Were these the only inputs that changed between Exhibit__(TEM-2), Exhibit__(TEM-3) and Exhibit__(TEM-4)?

A. Yes, that was the only change to inputs. However, as a result of these changes to the CapEx inputs, the model, as it is designed to do, also recalculated all of the necessary items that are used in determining the annual revenue requirement such as rate base, depreciation expense (both book and tax), Montana Consumer Counsel / Commission tax, interest expense, and income taxes. One manual change was necessary relating to the change in CapEx. This change was simply an adjustment to remove the revised 2014 CapEx amount from the first year revenue requirement calculation. Removing first Year CapEx (reducing rate base) was done for consistency with methodology utilized in Exhibit__(PJD-1) which establishes the requested revenue requirement in this proceeding.

Q. What was the resulting change in estimated revenue requirement assuming CapEx is 30% higher or 15% lower each of the next 30 years?

A. The table that follows illustrates the forecasted revenue requirement, net of revenue credits, for Exhibit__(TEM-3) on the left, Exhibit__(TEM-2) in the middle (provided for reference) and Exhibit__(TEM-4) on the right.

	($Thousands)				
CapEx Assumption	Plus 30%		No Change		Minus 15%
Year	Exhibit (TEM-3) Revenue Requirement, net of credits	VS.	Exhibit (TEM-2) Revenue Requirement, net of credits	VS.	Exhibit (TEM-4) Revenue Requirement, net of credits
2014	$ 131,043		$ 131,056		$ 131,063
2015	$ 129,296		$ 128,686		$ 128,381
2016	$ 140,381		$ 139,434		$ 138,960
2017	$ 140,454		$ 139,158		$ 138,510
2018	$ 139,515		$ 137,868		$ 137,044
2019	$ 139,154		$ 137,242		$ 136,286
2020	$ 138,198		$ 136,020		$ 134,931
2021	$ 138,486		$ 136,043		$ 134,821
2022	$ 138,265		$ 135,557		$ 134,203
2023	$ 139,167		$ 136,194		$ 134,708
2024	$ 139,775		$ 136,539		$ 134,920
2025	$ 140,666		$ 137,166		$ 135,416
2026	$ 140,119		$ 136,356		$ 134,475
2027	$ 139,667		$ 135,643		$ 133,631
2028	$ 139,438		$ 135,153		$ 133,011
2029	$ 138,867		$ 134,321		$ 132,049
2030	$ 137,528		$ 132,723		$ 130,321
2031	$ 137,574		$ 132,511		$ 129,979
2032	$ 138,308		$ 132,988		$ 130,327
2033	$ 136,652		$ 131,075		$ 128,286
2034	$ 138,055		$ 132,214		$ 129,294
2035	$ 140,227		$ 134,114		$ 131,057
2036	$ 141,378		$ 134,991		$ 131,797
2037	$ 142,584		$ 135,917		$ 132,584
2038	$ 143,839		$ 136,889		$ 133,414
2039	$ 145,137		$ 137,902		$ 134,285
2040	$ 146,485		$ 138,962		$ 135,200
2041	$ 147,884		$ 140,069		$ 136,162
2042	$ 149,336		$ 141,225		$ 137,170
2043	$ 150,841		$ 142,431		$ 138,226

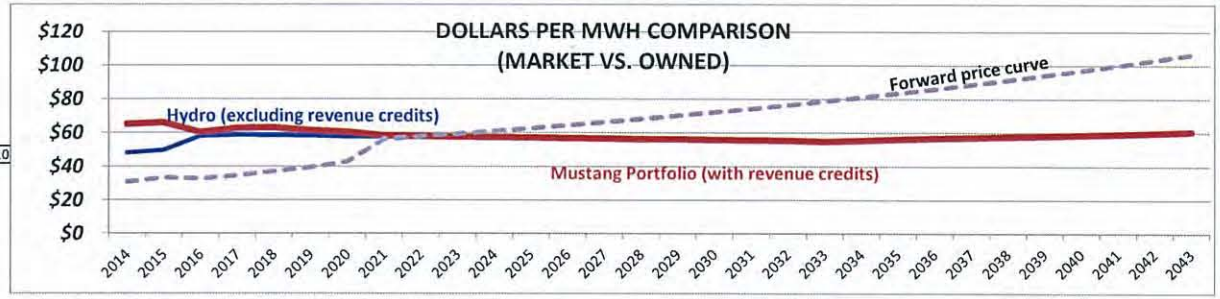
Q. Have the resulting revenue requirements from Exhibit__(TEM-3) and Exhibit__(TEM-4) been used to conduct comparisons of the supply portfolios that include the Hydros to the other portfolio alternatives on a NPV basis?

A. Yes. Please refer to the Prefiled Additional Issues Testimony of Joseph Stimatz.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit__(TEM-3)
Hydro Financials
(Plus 30% CAPEX SENSITIVITY)



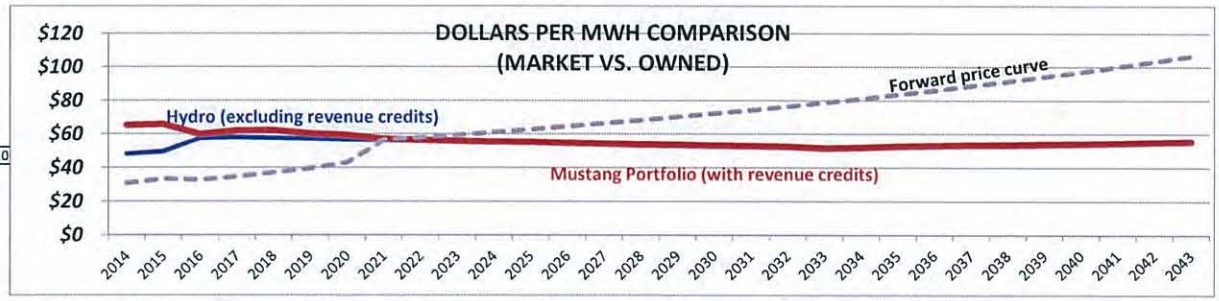
5	Price per kW	$ 1,422	
6	Ownership		
7	MW's	633	
8	Capacity Factor		
9			
10	Depreciation: Book & Tax (Years)	40.2	20.0
11	Return on Equity	10.00%	
12	Cost of Debt	4.50%	
13	Debt / Interest (Regulated or Bullet)	Regulated	RoR
14	Equity Capitalization	48.00%	7.14%
15	Escalation Rate (expense & capital)	2.50%	
16	Tax Rate	39.39%	
17	Dividend Payout (% of Net Income)	0.00%	
18	Estimated Purchase Price ($000's)	$ 900,000	

			2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
20	Rate Base (Beginning Balance)		900,000	869,046	807,763	813,263	794,147	771,393	749,853	729,442	710,075	690,811	671,464	652,043	632,504	612,869
21	Capex (130%)			16,680	(17,047)	11,953	15,589	11,050	11,326	11,610	11,900	12,197	12,502	12,837	13,135	13,475	13,800
22	Depreciation			(21,620)	(22,035)	(22,357)	(22,654)	(23,041)	(23,316)	(23,597)	(23,886)	(24,181)	(24,485)	(24,795)	(25,114)	(25,441)	(25,776)
23	Net Operating Loss Adjustment			(21,943)	(7,341)	29,284	0	0	0	0	0	0	0	0	0	0	0
24	Deferred Taxes			(4,071)	(14,861)	(13,381)	(12,050)	(10,764)	(9,550)	(8,423)	(7,381)	(7,280)	(7,365)	(7,462)	(7,561)	(7,669)	(7,774)
25	Rate Base (Ending Balance)		900,000	869,046	807,763	813,263	794,147	771,393	749,853	729,442	710,075	690,811	671,464	652,043	632,504	612,869	593,120
26	Gross Cash Requirements			(10,339)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)
27	Capex Adj. (eliminates first year average capex)			(8,340)	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Average Balance			865,844	831,231	803,339	796,532	775,597	753,449	732,474	712,585	693,270	673,964	654,580	635,100	615,513	595,821
30	MWs			633	571	439	439	439	439	439	439	439	439	439	439	439	439
33	Total MWh's			2,018,292	1,960,804	2,330,973	2,243,581	2,214,292	2,267,357	2,285,734	2,376,861	2,391,291	2,419,338	2,442,174	2,461,608	2,467,162	2,468,338
34	Revenue Requirement ($000 Annual)	NPV 30	$1,695,301	$131,043	$129,296	$140,381	$140,454	$139,515	$139,154	$138,198	$138,486	$138,265	$139,167	$139,775	$140,666	$140,119	$139,667
35	Revenue Requirement ($'s per MWh)			$64.93	$65.94	$60.22	$62.60	$63.01	$61.37	$60.46	$58.26	$57.82	$57.52	$57.23	$57.14	$56.79	$56.58
36	5 / 10 / 20 / 30 Year Level Price - Owned			$63.31	$61.51	$59.66	$59.36										
38	Procure at Market ($000 Annual)	NPV 30	$1,626,869	$61,826	$65,044	$76,003	$77,657	$82,177	$89,495	$97,672	$133,683	$137,987	$143,331	$148,827	$153,995	$158,727	$163,372
39	Market Curve ($'s per MWh)			$30.63	$33.17	$32.61	$34.61	$37.11	$39.47	$42.73	$56.24	$57.70	$59.24	$60.94	$62.56	$64.34	$66.19
40	5 / 10 / 20 / 30 Year Level Price - Market			$33.49	$40.93	$50.70	$56.96										

	Income Statement	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
43	Revenue Requirement	$131,043	$129,296	$140,381	$140,454	$139,515	$139,154	$138,198	$138,486	$138,265	$139,167	$139,775	$140,666	$140,119	$139,667
44	Revenue Credit	40,628	31,985	4,582	5,378	6,027	5,659	5,959	5,255	4,841	3,524	2,703	1,480	1,193	1,128
45	Cost of Sales (EPLT & WET Taxes)	948	841	523	534	538	530	530	514	512	508	506	501	500	500
46	Gross Margin	$170,724	$160,440	$144,440	$145,299	$145,004	$144,284	$143,627	$143,227	$142,594	$142,183	$141,972	$141,645	$140,812	$140,295
48	Fixed Operating & Maint Expense	21,939	22,973	23,084	23,661	24,253	24,923	25,546	26,185	26,840	27,538	28,227	28,933	29,635	30,397
49	PPLM Direct Expense (Corporate Expense)	5,369	5,503	5,641	5,782	5,926	6,075	6,226	6,382	6,542	6,705	6,873	7,045	7,221	7,401
50	A&G/Marketing Synergies	(1,924)	(1,989)	(1,906)	(1,954)	(2,932)	(3,006)	(3,081)	(3,158)	(3,237)	(3,318)	(3,401)	(3,486)	(3,573)	(3,662)
51	Supply Contingencies	-	-	-	-	-	-	-	125	125	125	125	374	125	125
52	Lease/Rent Payments (Kerr)	19,877	13,796	-	-	-	-	-	-	-	-	-	-	-	-
53	Property Taxes	14,050	13,881	13,160	13,357	13,558	13,761	13,968	14,177	14,390	14,606	14,825	15,047	15,273	15,502
54	MCC / MPSC Tax	695	685	744	744	739	738	732	734	733	738	741	746	743	740
55	Marketing Expense	2,363	2,442	2,341	2,399	3,601	3,691	3,784	3,878	3,975	4,075	4,176	4,281	4,388	4,498
56	Operating Expense	62,369	57,292	43,064	43,990	45,145	46,182	47,176	48,323	49,367	50,468	51,566	52,939	53,811	55,000
58	EBITDA	108,355	103,148	101,376	101,308	99,859	98,101	96,451	94,904	93,227	91,715	90,406	88,707	87,001	85,294
60	Depreciation	21,620	22,035	22,357	22,654	23,041	23,316	23,597	23,886	24,181	24,485	24,795	25,114	25,441	25,776
62	Operating Income	86,735	81,113	79,019	78,655	76,818	74,786	72,854	71,019	69,046	67,231	65,611	63,592	61,560	59,519
64	Interest Expense	(20,261)	(19,451)	(18,798)	(18,639)	(18,149)	(17,631)	(17,140)	(16,675)	(16,223)	(15,771)	(15,317)	(14,861)	(14,403)	(13,942)
65	Non-Cash Interest Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
67	Income before tax	66,474	61,663	60,221	60,016	58,669	57,155	55,714	54,344	52,823	51,460	50,294	48,731	47,157	45,576
69	Current Taxes	(21,602)	(7,563)	(8,662)	(10,078)	(10,995)	(11,764)	(12,466)	(13,099)	(12,614)	(11,981)	(11,412)	(10,686)	(9,944)	(9,203)
70	Deferred Taxes	(4,071)	(14,861)	(13,381)	(12,050)	(10,764)	(9,550)	(8,423)	(7,381)	(7,280)	(7,365)	(7,462)	(7,561)	(7,669)	(7,774)
71	Production Tax Credits	759	661	381	346	319	325	333	339	347	236	-	-	-	-
72	Income Tax Expense	(24,914)	(21,764)	(21,661)	(21,782)	(21,440)	(20,989)	(20,555)	(20,140)	(19,546)	(19,110)	(18,874)	(18,246)	(17,613)	(16,977)
74	**Net Income**	**$ 41,560**	**$ 39,899**	**$ 38,560**	**$ 38,234**	**$ 37,229**	**$ 36,166**	**$ 35,159**	**$ 34,204**	**$ 33,277**	**$ 32,350**	**$ 31,420**	**$ 30,485**	**$ 29,545**	**$ 28,599**
75	ETR	-37.4787%	-35.2946%	-35.9691%	-36.2943%	-36.5445%	-36.7237%	-36.8943%	-37.0602%	-37.0034%	-37.1350%	-37.5276%	-37.4426%	-37.3489%	-37.2494%
76	Regulated ROE	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%

	A	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG
1	**Exhibit__(TEM-3)**																
2	**Hydro Financials**																
3	**(Plus 30% CAPEX SENSITIVITY)**																
4																	
5	Price per kW																
6	Ownership																
7	MW's																
8	Capacity Factor																
9																	
10	Depreciation: Book & Tax (Years)																
11	Return on Equity																
12	Cost of Debt																
13	Debt / Interest (Regulated or Bullet)																
14	Equity Capitalization																
15	Escalation Rate (expense & capital)																
16	Tax Rate																
17	Dividend Payout (% of Net Income)																
18	Estimated Purchase Price ($000's)																
19		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
20	Rate Base (Beginning Balance)	593,120	573,260	553,314	533,228	513,028	492,705	472,263	458,616	451,864	445,175	438,566	432,026	425,518	419,044	412,603	406,198
21	Capex (130%)	14,145	14,522	14,861	15,233	15,613	16,004	16,404	16,814	17,234	17,665	18,107	18,559	19,023	19,499	19,986	20,486
22	Depreciation	(26,118)	(26,470)	(26,831)	(27,200)	(27,579)	(27,967)	(28,364)	(28,772)	(29,190)	(29,618)	(30,057)	(30,507)	(30,968)	(31,441)	(31,926)	(32,422)
23	Net Operating Loss Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Deferred Taxes	(7,887)	(7,997)	(8,117)	(8,232)	(8,357)	(8,479)	(1,687)	5,207	5,267	5,344	5,410	5,440	5,471	5,502	5,534	5,567
25	Rate Base (Ending Balance)	573,260	553,314	533,228	513,028	492,705	472,263	458,616	451,864	445,175	438,566	432,026	425,518	419,044	412,603	406,198	399,829
26	Gross Cash Requirements	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)
27	Capex Adj. (eliminates first year average capex)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Average Balance	576,017	556,114	536,098	515,955	495,693	475,311	458,266	448,067	441,346	434,697	428,123	421,599	415,108	408,650	402,228	395,840
29																	
30	MWs	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439
31																	
32																	
33	Total MWh's	2,480,472	2,473,519	2,460,921	2,470,529	2,493,733	2,493,733	2,493,733	2,493,733	2,493,733	2,493,733	2,493,733	2,493,733	2,493,733	2,493,733	2,493,733	2,493,733
34	Revenue Requirement ($000 Annual)	$139,438	$138,867	$137,528	$137,574	$138,308	$136,652	$138,055	$140,227	$141,378	$142,584	$143,839	$145,137	$146,485	$147,884	$149,336	$150,841
35	Revenue Requirement ($'s per MWh)	$56.21	$56.14	$55.88	$55.69	$55.46	$54.80	$55.36	$56.23	$56.69	$57.18	$57.68	$58.20	$58.74	$59.30	$59.88	$60.49
36	5 / 10 / 20 / 30 Year Level Price - Owned																
37																	
38	Procure at Market ($000 Annual)	$168,809	$173,236	$177,489	$183,362	$190,510	$196,178	$202,036	$208,075	$214,354	$220,872	$227,639	$234,615	$241,856	$249,401	$257,219	$265,297
39	Market Curve ($'s per MWh)	$68.06	$70.04	$72.12	$74.22	$76.40	$78.67	$81.02	$83.44	$85.96	$88.57	$91.28	$94.08	$96.99	$100.01	$103.15	$106.39
40	5 / 10 / 20 / 30 Year Level Price - Market																
41																	
42	***Income Statement***	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
43	Revenue Requirement	$139,438	$138,867	$137,528	$137,574	$138,308	$136,652	$138,055	$140,227	$141,378	$142,584	$143,839	$145,137	$146,485	$147,884	$149,336	$150,841
44	Revenue Credit	842	886	1,756	1,147	0	0	0	0	0	0	0	0	0	0	0	0
45	Cost of Sales (EPLT & WET Taxes)	501	499	501	500	499	499	499	499	499	499	499	499	499	499	499	499
46	Gross Margin	$139,780	$139,253	$138,782	$138,221	$137,809	$136,154	$137,557	$139,728	$140,879	$142,085	$143,340	$144,638	$145,986	$147,385	$148,837	$150,342
47																	
48	Fixed Operating & Maint Expense	31,157	31,900	32,698	33,517	34,353	33,951	34,800	35,670	36,561	37,475	38,412	39,373	40,357	41,366	42,400	43,460
49	PPLM Direct Expense (Corporate Expense)	7,586	7,776	7,970	8,170	8,374	8,583	8,798	9,018	9,243	9,474	9,711	9,954	10,203	10,458	10,719	10,987
50	A&G/Marketing Synergies	(3,754)	(3,848)	(3,944)	(4,042)	(4,143)	(4,247)	(4,353)	(4,462)	(4,573)	(4,688)	(4,805)	(4,925)	(5,048)	(5,174)	(5,304)	(5,436)
51	Supply Contingencies	125	125	125	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Lease/Rent Payments (Kerr)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Property Taxes	15,734	15,970	16,210	16,453	16,700	16,950	17,205	17,463	17,725	17,991	18,260	18,534	18,812	19,094	19,381	19,672
54	MCC / MPSC Tax	739	736	729	729	733	724	732	743	749	756	762	769	776	784	791	799
55	Marketing Expense	4,610	4,725	4,843	4,964	5,089	5,216	5,346	5,480	5,617	5,757	5,901	6,049	6,200	6,355	6,514	6,677
56	Operating Expense	56,198	57,385	58,631	59,791	61,105	61,178	62,527	63,911	65,322	66,765	68,242	69,754	71,300	72,882	74,502	76,159
57																	
58	EBITDA	83,582	81,869	80,151	78,430	76,704	74,976	75,030	75,817	75,558	75,320	75,098	74,885	74,686	74,503	74,335	74,184
59																	
60	Depreciation	26,118	26,470	26,831	27,200	27,579	27,967	28,364	28,772	29,190	29,618	30,057	30,507	30,968	31,441	31,926	32,422
61																	
62	Operating Income	57,463	55,399	53,320	51,230	49,126	47,009	46,665	47,045	46,368	45,701	45,041	44,378	43,718	43,062	42,410	41,761
63																	
64	Interest Expense	(13,479)	(13,013)	(12,545)	(12,073)	(11,599)	(11,122)	(10,723)	(10,485)	(10,328)	(10,172)	(10,018)	(9,865)	(9,714)	(9,562)	(9,412)	(9,263)
65	Non-Cash Interest Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66																	
67	Income before tax	43,984	42,386	40,776	39,157	37,526	35,887	35,942	36,560	36,040	35,530	35,023	34,512	34,004	33,500	32,998	32,499
68																	
69	Current Taxes	(8,449)	(7,695)	(6,927)	(6,159)	(5,376)	(4,593)	(12,259)	(20,260)	(20,122)	(20,008)	(19,883)	(19,716)	(19,550)	(19,386)	(19,225)	(19,065)
70	Deferred Taxes	(7,887)	(7,997)	(8,117)	(8,232)	(8,357)	(8,479)	(1,687)	5,207	5,267	5,344	5,410	5,440	5,471	5,502	5,534	5,567
71	Production Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Income Tax Expense	(16,336)	(15,692)	(15,043)	(14,391)	(13,733)	(13,072)	(13,945)	(15,053)	(14,856)	(14,664)	(14,473)	(14,275)	(14,079)	(13,884)	(13,691)	(13,498)
73																	
74	**Net Income**	$ 27,649	$ 26,693	$ 25,733	$ 24,766	$ 23,793	$ 22,815	$ 21,997	$ 21,507	$ 21,185	$ 20,865	$ 20,550	$ 20,237	$ 19,925	$ 19,615	$ 19,307	$ 19,000
75	ETR	-37.1397%	-37.0222%	-36.8922%	-36.7520%	-36.5957%	-36.4256%	-38.7993%	-41.1728%	-41.2194%	-41.2730%	-41.3240%	-41.3636%	-41.4043%	-41.4464%	-41.4899%	-41.5348%
76	Regulated ROE	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%

Exhibit__(TEM-4)
Hydro Financials
(Minus 15% CAPEX SENSITIVITY)



5	Price per kW	$ 1,422	
6	Ownership		
7	MW's	633	
8	Capacity Factor		
9			
10	Depreciation: Book & Tax (Years)	40.2	20.0
11	Return on Equity	10.00%	
12	Cost of Debt	4.50%	
13	Debt / Interest (Regulated or Bullet)	Regulated	RoR
14	Equity Capitalization	48.00%	7.14%
15	Escalation Rate (expense & capital)	2.50%	
16	Tax Rate	39.39%	
17	Dividend Payout (% of Net Income)	0.00%	
18	Estimated Purchase Price ($000's)	$ 900,000	

				2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
19																	
20	Rate Base (Beginning Balance)			900,000	863,348	797,879	799,709	775,835	750,071	725,552	702,190	679,896	657,733	635,516	613,250	590,908	568,502
21	Capex (85%)			10,906	(21,530)	7,816	10,193	7,225	7,406	7,591	7,780	7,975	8,174	8,393	8,588	8,811	9,023
22	Depreciation			(21,620)	(21,891)	(22,102)	(22,296)	(22,549)	(22,729)	(22,913)	(23,102)	(23,295)	(23,493)	(23,696)	(23,905)	(24,118)	(24,337)
23	Net Operating Loss Adjustment			(21,943)	(7,341)	29,284	0	0	0	0	0	0	0	0	0	0	0
24	Deferred Taxes			(3,995)	(14,707)	(13,167)	(11,770)	(10,440)	(9,196)	(8,040)	(6,973)	(6,843)	(6,898)	(6,963)	(7,026)	(7,098)	(7,165)
25	Rate Base (Ending Balance)		900,000	863,348	797,879	799,709	775,835	750,071	725,552	702,190	679,896	657,733	635,516	613,250	590,908	568,502	546,023
26	Gross Cash Requirements			(10,339)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)
27	Capex Adj. (eliminates first year average capex)			(5,453)	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Average Balance			865,882	823,440	791,621	780,599	755,780	730,638	706,698	683,870	661,641	639,451	617,210	594,906	572,532	550,089
29																	
30	MWs			633	571	439	439	439	439	439	439	439	439	439	439	439	439
31																	
32																	
33	Total MWh's			2,018,292	1,960,804	2,330,973	2,243,581	2,214,292	2,267,357	2,285,734	2,376,861	2,391,291	2,419,338	2,442,174	2,461,608	2,467,162	2,468,338
34	Revenue Requirement ($000 Annual)	NPV 30	$1,638,995	$131,063	$128,381	$138,960	$138,510	$137,044	$136,286	$134,931	$134,821	$134,203	$134,708	$134,920	$135,416	$134,475	$133,631
35	Revenue Requirement ($'s per MWh)			$64.94	$65.47	$59.61	$61.74	$61.89	$60.11	$59.03	$56.72	$56.12	$55.68	$55.25	$55.01	$54.51	$54.14
36	5 / 10 / 20 / 30 Year Level Price - Owned			$62.72	$60.51	$58.09	$57.38										
37																	
38	Procure at Market ($000 Annual)	NPV 30	$1,626,869	$61,826	$65,044	$76,003	$77,657	$82,177	$89,495	$97,672	$133,683	$137,987	$143,331	$148,827	$153,995	$158,727	$163,372
39	Market Curve ($'s per MWh)			$30.63	$33.17	$32.61	$34.61	$37.11	$39.47	$42.73	$56.24	$57.70	$59.24	$60.94	$62.56	$64.34	$66.19
40	5 / 10 / 20 / 30 Year Level Price - Market			$33.49	$40.93	$50.70	$56.96										
41																	
42	*Income Statement*			2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
43	Revenue Requirement			$131,063	$128,381	$138,960	$138,510	$137,044	$136,286	$134,931	$134,821	$134,203	$134,708	$134,920	$135,416	$134,475	$133,631
44	Revenue Credit			40,628	31,985	4,582	5,378	6,027	5,659	5,959	5,255	4,841	3,524	2,703	1,480	1,193	1,128
45	Cost of Sales (EPLT & WET Taxes)			948	841	523	534	538	530	530	514	512	508	506	501	500	500
46	Gross Margin			$170,744	$159,525	$143,019	$143,354	$142,533	$141,415	$140,360	$139,562	$138,531	$137,724	$137,117	$136,395	$135,168	$134,258
47																	
48	Fixed Operating & Maint Expense			21,939	22,973	23,084	23,661	24,253	24,923	25,546	26,185	26,840	27,538	28,227	28,933	29,635	30,397
49	PPLM Direct Expense (Corporate Expense)			5,369	5,503	5,641	5,782	5,926	6,075	6,226	6,382	6,542	6,705	6,873	7,045	7,221	7,401
50	A&G/Marketing Synergies			(1,924)	(1,989)	(1,906)	(1,954)	(2,932)	(3,006)	(3,081)	(3,158)	(3,237)	(3,318)	(3,401)	(3,486)	(3,573)	(3,662)
51	Supply Contingencies			-	-	-	-	-	-	-	125	125	125	125	374	125	125
52	Lease/Rent Payments (Kerr)			19,877	13,796	-	-	-	-	-	-	-	-	-	-	-	-
53	Property Taxes			14,050	13,881	13,160	13,357	13,558	13,761	13,968	14,177	14,390	14,606	14,825	15,047	15,273	15,502
54	MCC / MPSC Tax			695	680	736	734	726	722	715	715	711	714	715	718	713	708
55	Marketing Expense			2,363	2,442	2,341	2,399	3,601	3,691	3,784	3,878	3,975	4,075	4,176	4,281	4,388	4,498
56	Operating Expense			62,369	57,287	43,056	43,980	45,132	46,167	47,158	48,304	49,345	50,445	51,540	52,911	53,781	54,968
57																	
58	EBITDA			108,375	102,237	99,963	99,374	97,401	95,248	93,202	91,259	89,186	87,280	85,577	83,484	81,387	79,290
59																	
60	Depreciation			21,620	21,891	22,102	22,296	22,549	22,729	22,913	23,102	23,295	23,493	23,696	23,905	24,118	24,337
61																	
62	Operating Income			86,754	80,346	77,861	77,078	74,852	72,519	70,289	68,157	65,891	63,786	61,881	59,579	57,269	54,953
63																	
64	Interest Expense			(20,262)	(19,268)	(18,524)	(18,266)	(17,685)	(17,097)	(16,537)	(16,003)	(15,482)	(14,963)	(14,443)	(13,921)	(13,397)	(12,872)
65	Non-Cash Interest Expense			-	-	-	-	-	-	-	-	-	-	-	-	-	-
66																	
67	Income before tax			66,493	61,078	59,337	58,812	57,166	55,422	53,752	52,155	50,409	48,823	47,438	45,658	43,872	42,081
68																	
69	Current Taxes			(21,694)	(7,507)	(8,554)	(9,919)	(10,768)	(11,481)	(12,124)	(12,695)	(12,154)	(11,467)	(10,849)	(10,077)	(9,292)	(8,511)
70	Deferred Taxes			(3,995)	(14,707)	(13,167)	(11,770)	(10,440)	(9,196)	(8,040)	(6,973)	(6,843)	(6,898)	(6,963)	(7,026)	(7,098)	(7,165)
71	Production Tax Credits			759	661	381	346	319	325	333	339	347	236	-	-	-	-
72	Income Tax Expense			(24,931)	(21,553)	(21,340)	(21,343)	(20,889)	(20,351)	(19,831)	(19,329)	(18,650)	(18,130)	(17,812)	(17,103)	(16,390)	(15,676)
73																	
74	**Net Income**			$ 41,562	$ 39,525	$ 37,998	$ 37,469	$ 36,277	$ 35,071	$ 33,922	$ 32,826	$ 31,759	$ 30,694	$ 29,626	$ 28,555	$ 27,482	$ 26,404
75	ETR			-37.4936%	-35.2871%	-35.9632%	-36.2906%	-36.5407%	-36.7206%	-36.8926%	-37.0605%	-36.9977%	-37.1332%	-37.5476%	-37.4585%	-37.3594%	-37.2529%
76	Regulated ROE			10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%

	A	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG
1	**Exhibit__(TEM-4)**																
2	**Hydro Financials**																
3	**(Minus 15% CAPEX SENSITIVITY)**																
4																	
5	Price per kW																
6	Ownership																
7	MW's																
8	Capacity Factor																
9																	
10	Depreciation: Book & Tax (Years)																
11	Return on Equity																
12	Cost of Debt																
13	Debt / Interest (Regulated or Bullet)																
14	Equity Capitalization																
15	Escalation Rate (expense & capital)																
16	Tax Rate																
17	Dividend Payout (% of Net Income)																
18	Estimated Purchase Price ($000's)																
19		**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
20	Rate Base (Beginning Balance)	**546,023**	**523,469**	**500,861**	**478,160**	**455,386**	**432,530**	**409,598**	**393,458**	**384,179**	**374,941**	**365,755**	**356,614**	**347,495**	**338,397**	**329,321**	**320,269**
21	**Capex (85%)**	9,249	9,495	9,717	9,960	10,209	10,464	10,725	10,994	11,268	11,550	11,839	12,135	12,438	12,749	13,068	13,395
22	Depreciation	(24,561)	(24,791)	(25,027)	(25,269)	(25,516)	(25,770)	(26,030)	(26,296)	(26,570)	(26,850)	(27,137)	(27,431)	(27,732)	(28,042)	(28,358)	(28,683)
23	Net Operating Loss Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Deferred Taxes	(7,241)	(7,312)	(7,391)	(7,465)	(7,548)	(7,627)	(835)	6,024	6,063	6,113	6,157	6,176	6,196	6,217	6,238	6,259
25	Rate Base (Ending Balance)	523,469	500,861	478,160	455,386	432,530	409,598	393,458	384,179	374,941	365,755	356,614	347,495	338,397	329,321	320,269	311,240
26	Gross Cash Requirements	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)	(7,173)
27	Capex Adj. (eliminates first year average capex)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Average Balance	**527,573**	**504,992**	**482,337**	**459,600**	**436,785**	**413,891**	**394,355**	**381,645**	**372,387**	**363,175**	**354,011**	**344,881**	**335,773**	**326,686**	**317,622**	**308,581**
29																	
30	MWs	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439	439
31																	
32																	
33	Total MWh's	2,480,472	2,473,519	2,460,921	2,470,529	2,493,733	2,493,733	2,493,733	2,493,733	2,493,733	2,493,733	2,493,733	2,493,733	2,493,733	2,493,733	2,493,733	2,493,733
34	Revenue Requirement ($000 Annual)	$133,011	$132,049	$130,321	$129,979	$130,327	$128,286	$129,294	$131,057	$131,797	$132,584	$133,414	$134,285	$135,200	$136,162	$137,170	$138,226
35	Revenue Requirement ($'s per MWh)	$53.62	$53.39	$52.96	$52.61	$52.26	$51.44	$51.85	$52.55	$52.85	$53.17	$53.50	$53.85	$54.22	$54.60	$55.01	$55.43
36	5 / 10 / 20 / 30 Year Level Price - Owned																
37																	
38	Procure at Market ($000 Annual)	$168,809	$173,236	$177,489	$183,362	$190,510	$196,178	$202,036	$208,075	$214,354	$220,872	$227,639	$234,615	$241,856	$249,401	$257,219	$265,297
39	Market Curve ($'s per MWh)	$68.06	$70.04	$72.12	$74.22	$76.40	$78.67	$81.02	$83.44	$85.96	$88.57	$91.28	$94.08	$96.99	$100.01	$103.15	$106.39
40	5 / 10 / 20 / 30 Year Level Price - Market																
41																	
42	***Income Statement***	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
43	Revenue Requirement	$133,011	$132,049	$130,321	$129,979	$130,327	$128,286	$129,294	$131,057	$131,797	$132,584	$133,414	$134,285	$135,200	$136,162	$137,170	$138,226
44	Revenue Credit	842	886	1,756	1,147	0	0	0	0	0	0	0	0	0	0	0	0
45	Cost of Sales (EPLT & WET Taxes)	501	499	501	500	499	499	499	499	499	499	499	499	499	499	499	499
46	Gross Margin	$133,352	$132,436	$131,575	$130,627	$129,829	$127,787	$128,795	$130,559	$131,298	$132,085	$132,916	$133,786	$134,702	$135,663	$136,671	$137,727
47																	
48	Fixed Operating & Maint Expense	31,157	31,900	32,698	33,517	34,353	33,951	34,800	35,670	36,561	37,475	38,412	39,373	40,357	41,366	42,400	43,460
49	PPLM Direct Expense (Corporate Expense)	7,586	7,776	7,970	8,170	8,374	8,583	8,798	9,018	9,243	9,474	9,711	9,954	10,203	10,458	10,719	10,987
50	A&G/Marketing Synergies	(3,754)	(3,848)	(3,944)	(4,042)	(4,143)	(4,247)	(4,353)	(4,462)	(4,573)	(4,688)	(4,805)	(4,925)	(5,048)	(5,174)	(5,304)	(5,436)
51	Supply Contingencies	125	125	125	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Lease/Rent Payments (Kerr)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Property Taxes	15,734	15,970	16,210	16,453	16,700	16,950	17,205	17,463	17,725	17,991	18,260	18,534	18,812	19,094	19,381	19,672
54	MCC / MPSC Tax	705	700	691	689	691	680	685	695	699	703	707	712	717	722	727	733
55	Marketing Expense	4,610	4,725	4,843	4,964	5,089	5,216	5,346	5,480	5,617	5,757	5,901	6,049	6,200	6,355	6,514	6,677
56	Operating Expense	56,164	57,349	58,593	59,751	61,063	61,133	62,480	63,863	65,271	66,712	68,187	69,696	71,240	72,820	74,437	76,092
57																	
58	EBITDA	77,188	75,087	72,982	70,876	68,766	66,654	66,315	66,696	66,027	65,373	64,729	64,090	63,461	62,843	62,234	61,636
59																	
60	Depreciation	24,561	24,791	25,027	25,269	25,516	25,770	26,030	26,296	26,570	26,850	27,137	27,431	27,732	28,042	28,358	28,683
61																	
62	Operating Income	52,627	50,296	47,955	45,607	43,249	40,884	40,285	40,399	39,458	38,523	37,592	36,659	35,729	34,801	33,875	32,952
63																	
64	Interest Expense	(12,345)	(11,817)	(11,287)	(10,755)	(10,221)	(9,685)	(9,228)	(8,931)	(8,714)	(8,498)	(8,284)	(8,070)	(7,857)	(7,644)	(7,432)	(7,221)
65	Non-Cash Interest Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66																	
67	Income before tax	40,282	38,479	36,669	34,852	33,029	31,199	31,057	31,469	30,744	30,025	29,308	28,589	27,872	27,157	26,443	25,732
68																	
69	Current Taxes	(7,718)	(6,928)	(6,126)	(5,326)	(4,515)	(3,706)	(11,293)	(19,174)	(18,932)	(18,706)	(18,473)	(18,211)	(17,951)	(17,692)	(17,435)	(17,179)
70	Deferred Taxes	(7,241)	(7,312)	(7,391)	(7,465)	(7,548)	(7,627)	(835)	6,024	6,063	6,113	6,157	6,176	6,196	6,217	6,238	6,259
71	Production Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Income Tax Expense	(14,958)	(14,239)	(13,516)	(12,792)	(12,063)	(11,333)	(12,128)	(13,150)	(12,869)	(12,592)	(12,316)	(12,035)	(11,755)	(11,476)	(11,197)	(10,920)
73																	
74	**Net Income**	**$ 25,323**	**$ 24,240**	**$ 23,152**	**$ 22,061**	**$ 20,966**	**$ 19,867**	**$ 18,929**	**$ 18,319**	**$ 17,875**	**$ 17,432**	**$ 16,993**	**$ 16,554**	**$ 16,117**	**$ 15,681**	**$ 15,246**	**$ 14,812**
75	ETR	-37.1342%	-37.0055%	-36.8609%	-36.7024%	-36.5227%	-36.3231%	-39.0505%	-41.7871%	-41.8597%	-41.9399%	-42.0210%	-42.0957%	-42.1744%	-42.2573%	-42.3446%	-42.4369%
76	Regulated ROE	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2013.12.85
PPLM Hydro Assets Purchase
NorthWestern Energy

PREFILED ADDITIONAL ISSUES TESTIMONY OF

JOSEPH M. STIMATZ

ON BEHALF OF NORTHWESTERN ENERGY

Witness Information

Q. Please state your name and business address.

A. My name is Joseph (Joe) M. Stimatz. My business address is 40 East Broadway, Butte, Montana 59701.

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

A. I am employed by NorthWestern Energy ("NorthWestern") as the Manager of Asset Optimization in the Energy Supply Market Operations group.

Q. Are you the same Joseph Stimatz who submitted prefiled direct testimony and prefiled supplemental testimony in this docket?

A. Yes.

Q. What is the purpose of this testimony?

A. In the Montana Public Service Commission's April 4 Notice of Additional Issues, it directed NorthWestern to provide testimony on, among other

things, the potential range of future capital expenditures ("CapEx") and the effect of those potential expenditures on the net present value ("NPV") of supply portfolio costs. This testimony addresses the NPV effect of both higher and lower CapEx than NorthWestern forecast in its original analysis.

Q. Had NorthWestern previously analyzed the cost of supply portfolio alternatives?

A. Yes. In my earlier testimony in this docket, I described the stochastic modeling results from NorthWestern's 2013 Electricity Supply Resource Procurement Plan Supplement ("2013 Plan Supplement"), including the NPV of costs associated with a number of supply portfolio cases. At NorthWestern's direction, Ascend Analytics modeled six portfolio cases: 1) existing resources in the supply portfolio plus market purchases to meet load requirements (the "Current" portfolio); 2) existing resources plus a combined cycle plant, supplemented with market purchases ("Current Plus CC"); 3) existing resources plus the Hydros, supplemented with market purchases ("Current Plus Hydro"); 4) existing resources plus an LMS 100 combustion turbine added in 2018, supplemented with market purchases ("Current Plus LMS 2018"); 5) existing resources plus an LMS 100 added in 2025 plus 100 MW of wind generation added in 2025, supplemented with market purchases ("Current Plus LMS Plus Wind 2025"); and existing resources plus a combined cycle plant added in 2025 plus 100 MW of

wind added in 2025, supplemented with market purchases ("Current Plus CC Plus Wind 2025").

Q. What were the results of that analysis?

A. As described in my supplemental testimony on pages 4-6, the Current Plus Hydro portfolio significantly outperformed all of the other alternatives. The table below, which is the same as the table on page 5 of my supplemental testimony, shows that on a risk-adjusted NPV basis, the cost of the Current Plus Hydro portfolio is approximately $332 million lower than the cost of the next best alternative.

Stochastic Modeling Results ($Billions)		
Portfolio	NPV of Costs	NPV vs. Currrent + Hydro
Current + Hydro	$5.851	
Current + CC + Wind 2025	$6.183	$0.332
Current	$6.227	$0.376
Current + LMS + Wind 2025	$6.235	$0.384
Current + CC	$6.237	$0.386
Current + LMS 2018	$6.294	$0.443

Q. Did NorthWestern perform additional analysis regarding capital expenditures?

A. Yes. As a result of the Commission's identification of additional issues, NorthWestern modeled two additional CapEx scenarios: 1) increased capital expenditures of 30% for each year of the study period; and 2) decreased capital expenditures of 15% for each year of the study period.

Please see the Prefiled Additional Issues Testimony of John VanDaveer for a description of the rationale for this range. The Prefiled Additional Issues Testimony of Travis E. Meyer describes how the additional CapEx scenarios were incorporated into NorthWestern's modeling of the revenue requirement for the Hydros.

Q. Please describe the additional analysis necessary to incorporate the capital expenditures and resulting revenue requirement into the portfolio comparison.

A. Since the alternate capital expenditure assumptions do not affect the dispatch of the Hydros or the other elements of the portfolios, no additional stochastic modeling was necessary. Rather, the revenue requirements that include the 30% increase were used to calculate the NPV of portfolio costs, and this NPV was compared to the costs of the other portfolios. Similarly, the revenue requirements associated with the 15% reduction were used to calculate the NPV for that scenario.

Q. What conclusions do you draw from the comparisons?

A. Evaluating the range of potential capital expenditures reaffirms NorthWestern's conclusions from the original modeling. Even if capital expenditures turn out to be 30% higher than NorthWestern's forecasts, the Current Plus Hydro portfolio would still be far superior to the other alternatives. The table below shows that even with capital expenditures

increased by 30% each year, on a risk adjusted NPV basis, the cost of the Current Plus Hydro portfolio is nearly $300 million lower than the next best alternative.

Stochastic Modeling Results ($Billions)		
Portfolio	NPV of Costs	NPV vs. Current + Hydro
Current + Hydro, 30% Higher CapEx	**$5.884**	
Current + CC + Wind 2025	$6.183	$0.299
Current	$6.227	$0.343
Current + LMS + Wind 2025	$6.235	$0.351
Current + CC	$6.237	$0.353
Current + LMS 2018	$6.294	$0.410

The table below shows the risk adjusted NPV comparisons for the scenario with 15% lower capital expenditures each year. In this scenario, the Current Plus Hydro portfolio costs are approximately $355 million lower than the next best alternative.

Stochastic Modeling Results ($Billions)		
Portfolio	NPV of Costs	NPV vs. Currrent + Hydro
Current + Hydro, 15% Lower CapEx	**$5.828**	
Current + CC + Wind 2025	$6.183	$0.355
Current	$6.227	$0.399
Current + LMS + Wind 2025	$6.235	$0.407
Current + CC	$6.237	$0.409
Current + LMS 2018	$6.294	$0.466

Q. Does this conclude your testimony?

A. Yes, it does.