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

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IN THE MATTER OF NorthWestern Energy's	)	REGULATORY DIVISION
Application for Approval to Purchase and Operate	)	
PPL Montana's Hydroelectric Facilities, for	)	DOCKET NO. D2013.12.85
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	)	

Direct Testimony

of

John W. Wilson

on behalf of

The Montana Consumer Counsel

March 28, 2014

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I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is John W. Wilson. I am President of J.W. Wilson & Associates, Inc. Our offices are at 1601 North Kent Street, Suite 1104, Arlington, Virginia 22209.

Q. PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND.

A. I hold a B.S. degree with senior honors and a Masters Degree in Economics from the University of Wisconsin. I have also received a Ph.D. in Economics from Cornell University. My major fields of study were industrial organization and public regulation of business, and my doctoral dissertation was a study of utility pricing and regulation.

Q. HOW HAVE YOU BEEN EMPLOYED SINCE THAT TIME?

A. After completing my graduate education I was an assistant professor of economics at the United States Military Academy, West Point, New York. In that capacity, I taught courses in both economics and government. While at West Point, I also served as an economic consultant to the Antitrust Division of the United States Department of Justice.

After leaving West Point, I was employed by the Federal Power Commission, first as a staff economist and then as Chief of FPC's Division of Economic Studies. In that capacity, I was involved in regulatory matters involving most phases of FPC regulation of electric utilities and the natural gas industry. Since 1973 I have been employed as an economic consultant by various clients, including federal, state, provincial and local governments, private enterprise and nonprofit organizations. This work has pertained to a wide range of issues concerning public utility regulation, insurance rate regulation, antitrust matters and economic and financial analysis. In 1975 I formed J.W. Wilson & Associates, Inc., a Washington, D.C. corporation. Since that time I have worked as a consultant on most of the major public utility rate cases before the Montana Public Service Commission (MPSC). In the 1970s I was retained by the Commission Staff, and since the 1980s I have been a consultant to the Montana Consumer Counsel (MCC).

Q. WOULD YOU PLEASE DESCRIBE SOME OF YOUR ADDITIONAL PROFESSIONAL ACTIVITIES?

A. I have authored a variety of articles and monographs, including a number of studies dealing with utility regulation and economic policy. In addition to working for the MPSC and the MCC, I have consulted on regulatory, financial and competitive market matters with the Federal Communications Commission, the National Academy of Sciences, the Ford Foundation, the National Regulatory Research Institute (NRRI), the National Association of

Regulatory Utility Commissioners (NARUC), the Electric Power Research Institute (EPRI), the Edison Electric Institute (EEI), the American Public Power Association (APPA), the National Rural Electric Cooperative Association (NRECA), the U.S. Department of Justice Antitrust Division, the Federal Trade Commission Bureau of Competition, the Commerce Department, the Department of the Interior, the Department of Energy, the Small Business Administration, the Department of Defense, the Tennessee Valley Authority, the Federal Energy Administration, and numerous state and provincial agencies and legislative bodies in the United States and Canada.

Previously, I was a member of the Economics Committee of the U.S. Water Resources Council, the Federal Power Commission (FPC) Coordinating Representative for the Task Force on Future Financial Requirements for the National Power Survey, the Advisory Committee to the National Association of Insurance Commissioners (NAIC) Task Force on Profitability and Investment Income, and the NAIC's Advisory Committee on Nuclear Risks.

In addition, I have testified as an expert witness in court proceedings dealing with competition in the electric power industry and on regulatory matters before more than 50 Federal and State regulatory bodies throughout the United States and Canada. I have also appeared on numerous occasions as an expert witness at the invitation of U.S. Senate and Congressional Committees dealing with antitrust and regulatory legislation. In addition, I have been retained as an expert on regulatory matters by more than 25 State and Federal regulatory agencies. I have also participated as a speaker, panelist, or moderator in many professional conferences and programs dealing with business regulation, financial issues, economic policy and antitrust matters. I am a member of the American Economic Association and an associate member of the American Bar Association and the ABA's Antitrust, Insurance and Regulatory Law Sections.

II. OVERVIEW OF TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am presenting testimony in this proceeding on behalf of the Montana Consumer Counsel (MCC).

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony in this case deals with NorthWestern Energy's ("NWE" or "the Company") proposed acquisition of PPLM's hydroelectric dams ("the hydros") that were sold to PPL by Montana Power in 1998. Altogether, there are 12 dams, one of which (Hebgen) is a water storage facility that does not, itself, generate electricity, and another one (the Kerr Project) will be resold to the Confederated Salish and Kootenai Tribes of the Flathead Reservation ("CSKT") in 2015. The total cost of the proposed acquisition is $900 million, of which $30 million will be recovered shortly after the purchase through the sale of Kerr.[1] The $900 million purchase price is comprised of $553 million of original cost plus $347 million of acquisition adjustment.[2] [3] The total net capacity of these dams is 633 MW, of which 30.65% is accounted for by Kerr. Thus, the net cost of the remaining 439 MW of capacity, after the sale of Kerr next year, is $1,982 per Kw.

According to the Company, the 2014 test year revenue requirement associated with this plant acquisition is $128,402,190, of which $66,570,901 consists of costs and $61,831,289 is return on rate base. According to the Company's comparative cost analysis, while this test year cost is much higher than the cost of procuring equivalent power in the

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[1] An arbitration panel decided on March 3, 2014 that the price to be paid for Kerr by CSKT will be only $18.3 million. However, pursuant to true-up provisions in Section 5.18 of the PSA, PPLM will pay NWE the difference between $30 million and this price. Therefore, NWE's effective compensation for Kerr remains at $30 million.

[2] See KGK-9. NWE witness Bird presents slightly different figures -- $579 million of original cost and $321 million of acquisition adjustment. (See BBB-26).

[3] It should be noted that a significant part of this acquisition adjustment ($89.3 million) is associated with the Kerr Project, but is proposed to remain with NWE and in its rate base after the sale of Kerr to CSKT. Thus, under the Company's proposal, a substantial part of the cost of Kerr will continue to be charged to NWE's ratepayers for many years after the asset itself, and all of its electricity production is transferred to CSKT.

competitive market, over time the long term cost to ratepayers will be roughly equivalent[4] to the projected cost of market purchases.

The Company has presented two types of cost comparisons which it calls "deterministic" and "stochastic." These comparisons indicate that the Company's ratemaking proposal for the hydros acquisition will result in much higher immediate costs for Montana ratepayers than would projected competitive market purchases for well over a decade. Over the longer term, however, the Company's deterministic cost comparisons indicate that the present value of ratepayer costs will be only slightly greater with the hydros purchase, and the stochastic cost comparisons indicate that the hydros purchase could result in lower long term costs.

The reason the Company's stochastic results appear more favorable for the hydros is attributable to two factors. First, NWE incorporates a $1.679 billion cost offset for the hydros in its stochastic model for assumed appreciation of hydro plant value over the next thirty years (rather than depreciation). Second the Company's stochastic model adds a $451 million cost increment for market alternatives to reflect its risk assumptions for key market purchase cost variables, such as the possible doubling of assumed CO2 tax penalties for fossil fuel generation and additional fuel cost

[4] Over the next 30 years the Company's own deterministic model estimates that the net present value of the hydros' comparative costs remains $31 million above the Company's projection of the net present value of alternative market purchases.

uncertainties.[5] As discussed below, I consider the Company's stochastic results to be unreasonably biased in favor of the hydros purchase, as they incorporate these very substantial risk penalties for alternative market purchase costs but no risks or uncertainties for certain critical hydros cost assumptions – such as very optimistic and comparatively low (but highly uncertain) long term repair, refurbishment and rehabilitation costs for the aging hydro pants. In the testimony below I will try to give the Commission a more complete picture and additional perspective to assist in evaluating NWE's ratemaking request.

Q. HOW MUCH HIGHER IS THE COMPANY'S $128.4 MILLION TEST YEAR REVENUE REQUIREMENT FOR THE HYDROS THAN THE ALTERNATIVE COST OF PURCHASED POWER?

A. According to the Company's analysis presented in Exhibit TEM-2, the alternative cost of the same amount of purchased power in 2014 would be about $62 million. So, in the Company's test year the cost of the hydros to Montana consumers would be more than double the alternative cost of power purchased in the competitive market. This, quite clearly, is far more than the 4.2 percent rate increase that is mistakenly claimed in the Company's filing. The Company's calculation of the mistaken 4.2 percent rate increase fails to account for the rate increasing effect of substituting the

[5] See JMS-43 and response to PSC-047.

hydros' costs for less expensive purchased power alternatives. By the Company's own calculations, this disparate cost continues each year far into the future.

Q. DOES NWE FORECAST THAT THE COST OF THE HYDROS TO MONTANA CONSUMERS WILL REMAIN ABOVE ALTERNATIVE COMPETITIVE MARKET COSTS SUBSEQUENT TO THE TEST YEAR?

A. Yes. Again, according to the Company's analysis, over the first eight years of owning the hydros Montana consumers will be required to pay more than $400 million more than they would have to pay if competitive market purchases were the power supply source rather than the hydros. This estimated cost difference depends heavily on the assumptions underlying the Company's analysis. Because these underlying assumptions regarding future hydros' costs are quite modest and make the hydros' costs appear as low as possible (which I will discuss below), if comparative CO2 costs and capital expenditure trends turn out to be less favorable than NWE assumes for the hydros, the excess cost to Montana consumers will turn out to be considerably greater than $400 million.

Q. IS IT YOUR OPINION THAT THE COMMISSION SHOULD REJECT NWE'S PROPOSAL TO ACQUIRE THE HYDROS?

A. Rather than rejecting the proposal to acquire the hydros it would be preferable to modify and improve it (especially the Company's ratemaking proposal) so that the cost to current ratepayers is more reasonable. While there may be long term benefits to ownership, a current price that is double the available competitive market price, resulting in a total $400 million cost increase to current ratepayers over the next eight years, is not desirable. Also, both the magnitude and timing of possible long term benefits are unknown, and the estimates Northwestern presents are highly dependent on key assumptions that require further consideration. The potential for net benefits to Montana consumers, which is the crucial element in evaluating whether this is a good acquisition or not, essentially depends on the price that NorthWestern will pay to PPLM and the plan for recovering this cost from ratepayers. Under the price and plan for recovery that NorthWestern proposes in this filing consumers would be severely penalized in the near term (initially double alternative competitive market prices, and $400 million above the available alternative cost level over the next eight years) in order for future ratepayers to gain uncertain projected benefits (such as avoidance of assumed hypothetical high carbon tax levels that have not been approved or adopted) at some uncertain future date. If the

Commission agrees that a hydros purchase should be approved it is important to find ways to either better the deal or at least to shift a significant part of the cost to future beneficiaries and not burden current consumers with a huge upfront bill that greatly exceeds alternative current and projected costs in order to hopefully attain speculative benefits for future generations.

Q. DO YOU THINK IT IS SURPRISING THAT MANY OF NWE'S CUSTOMERS MAY BE INTERESTED IN REACQUIRING THESE HYDROELECTRIC FACILITIES, AS COMPANY WITNESS ROWE DESCRIBES IN HIS TESTIMONY?

A. No. There is understandably frustration in Montana and a feeling that Montana consumers should get back what “is rightfully theirs.” Unfortunately, that recapture is not really economically possible. What should have rightfully belonged to Montana consumers are the economic benefits associated with these hydroelectric facilities. Those benefits, however, were captured by PPL and they are here reflected in the proposed $900 million purchase price. Instead of mistakenly assuming that these economic benefits can be recaptured by paying that price, what Montana consumers and the Commission now require is a clear-eyed economic decision about how best to proceed based on current realities.

Q. HAS THE COMPANY'S ANALYSIS SHOWN THAT OTHER BUYERS ARE WILLING TO PAY $900 MILLION FOR THESE HYDRO ASSETS AND THAT NWE MUST PAY THAT PRICE TO ACQUIRE THEM?

A. That has not been shown. However, NWE has prepared a discounted cash flow ("DCF") analysis based on certain key market assumptions from which it has concluded that alternative buyers would likely be willing to pay a price in a range centering around $826 million.[6] According to NWE, it was concerned that, as a regulated utility, it would be at a competitive disadvantage in bidding for the hydros and might either be outbid in a competitive sale or its bid might be viewed less favorably than a bid from an unregulated merchant generator that did not have regulatory approval requirements. The Company concluded that its bid for the hydros would have to overcome these concerns and be sufficient to negate PPL's need to restart the competitive sales process after the receipt of NWE's bid. (See pages BBB-11 through BBB-14 of Brian Bird's testimony) Thus, it is my understanding that NWE's $900 million bid was set high enough in the Company's judgment to foreclose competitive offers, and it achieved that goal.

[6] NWE also commissioned a fairness opinion from Blackstone Advisory Partners, which concluded that the proposed price was fair to NWE, assuming the accuracy of all of the Company's forecasts, including NWE's expected regulatory outcomes (See Exhibit AO-01), as well as financial advice from Credit Suisse. There appears to be little question that NWE's proposal, if approved by the Commission, is expected to be a good and profitable deal for the Company and its stockholders.

Q. DOES THE COMPANY'S DCF ANALYSIS REASONABLY DEMONSTRATE THAT AN ALTERNATIVE MERCHANT GENERATOR, WHO WAS INTERESTED IN SELLING THE HYDRO'S PRODUCTION IN THE COMPETITIVE MARKET, WOULD BE WILLING TO PAY $826 MILLION FOR THESE FACILITIES?

A. I do not agree that the Company's DCF analysis reasonably demonstrates that conclusion. Most importantly in this regard, the Company's DCF analysis includes $247.4 million of hypothetical and speculative capitalized CO2 tax costs in the $826 million amount. These are not costs that an alternative competitive buyer would be able to pass on to customers in competitive markets until (when and if) the hypothetical assumed carbon taxes were actually implemented. In contrast, the Company's proposal in this case is to include similar hypothetical future carbon taxes in the rates that current ratepayers would be required to pay immediately. An unregulated alternative buyer of these plants would simply not be able to coerce such risky advance payments from customers in competitive markets.

Another doubtful feature of the Company's DCF valuation is its premise that a competitive buyer would value these plants assuming that capital expenditures to keep the plants running and safe would be only $8.5 million annually for the next several decades, when PPLM's own actual and budgeted capital expenditures over the last ten years (2008-2017) averaged \$35.6 million. Even if one were to assume that an alternative buyer would expect future capital expenditures to be half that historical level, the DCF value would be \$512 million rather than \$826 million if a competitive buyer was unwilling to assume the risk of funding the \$247.4 million of hypothetical CO2 costs embedded in NWE's DCF analysis.

Finally, despite very low assumed expenditures for repair and renovation, the Company's DCF valuation assumes that an alternative competitive buyer would assume the realization of a \$1.073 ***billion*** residual value for these plants in twenty years (which is more than was paid for them), rather than assuming any depreciation.

I think it very doubtful that a competitive merchant buyer would (1) be willing to fund \$247.4 million of hypothetical CO2 taxes that may not be recoverable, (2) assume that capital expenditures for repairs and renovation would be only 25 percent of historical levels, and (3) presume a terminal value of more than a billion dollars for these facilities. Those are the assumptions that NWE's competitive market valuation depends on.

Q. DO YOU AGREE WITH THE COMPANY'S COMPARATIVE LONG TERM COST ANALYSIS?

A. While it is important to consider long-term costs and benefits when evaluating long-lived resource additions, the Company's comparative cost analysis is highly questionable, and there are important qualifications that must be noted. The Company, which offered the Commission similar optimistic views regarding the Colstrip IV (CU4) acquisition several years ago, characterizes the hydros purchase as "a once in a lifetime opportunity." The real question here, however, is whether the acquisition, as proposed in this case, represents a good opportunity *for ratepayers*. That depends on whether the acquisition is likely to result in higher or lower electric power costs for ratepayers.

There is little doubt that the Company's pricing proposal for purchasing these dams will increase ratepayer costs very substantially at least until such time as carbon taxes are imposed at levels as high or higher than the hypothetical levels that are assumed by NorthWestern. Whether that cost increase will be reversed in more distant years for future generations also depends on the accuracy of the driving assumptions (such as very low capital expenditures) that NWE has made in its speculative long term cost analysis. On the other hand, there is little doubt that the virtually risk-free proposed addition of $900 million to NWE's rate base is a great profit opportunity for the Company, as Montana consumers will be required to compensate NWE for these costs, plus hundreds of millions in associated profits for decades, regardless of whether the acquisition turns out to be a good deal *for ratepayers*.

As noted above, the hydros add more than $61 million of return on rate base for NWE in the test year that would not occur if lower cost alternative competitive market purchases were selected instead. This increase in the Company's return to investors is roughly equal to the excess costs that will be charged to ratepayers if the hydros purchase is approved by the Commission without improving the terms proposed by NWE. So, whether or not one agrees that the hydros purchase is a "once in a lifetime" opportunity, there is no doubt that the Commission's approval of NorthWestern's pricing proposal would be a great profit opportunity for NWE[7].

As one Company witness has correctly explained in this case, despite the negative value that is now placed on additional Colstrip generation capacity, NWE's high cost acquisition of CU4 continues to be a valuable asset *for the Company*.[8] That, of course, is correct, as Montana ratepayers

[7] NWE's comparative cost analysis indicates that, under the Company's ratemaking proposal, the hydros acquisition will add $796 million to stockholders' return on equity over the next thirty years.

[8] The Company's testimony in this case reveals that NWE offered PPLM a considerably higher price for the hydros alone than it did for the hydros together with PPLM's coal-fired generating plants – implying a substantial negative value for the coal fired plants. In response to MCC-004 which asked whether the

will have to continue to pay for CU4 costs and substantial profits for NWE on that $400 million acquisition for many more years, despite the fact that it is now recognized to be an exceedingly high cost resource in comparison with much lower cost available power supplies at market prices.

Q. HOW DO YOU EVALUATE THE COMPANY'S COMPARATIVE COST ANALYSIS?

A. In evaluating NWE's hydros purchase proposal and the cost of electric supply alternatives, one must first recognize that the Company's comparative cost analysis depends heavily upon the addition of substantial hypothetical carbon tax penalties to the hydros principal alternative -- purchased power costs. Without the Company's assumed carbon tax adders to projected purchased power costs (which total $1.375 billion from 2021 to 2043), NWE's projected cost of power from the hydros would be significantly more expensive than the Company's alternative projected competitive market purchase costs for decades. Not only does NWE's

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Company believes that its owned interest in CU4 now has a negative value, Company witness Hines responded:

> NorthWestern does not believe that its owned interest in Colstrip Unit 4 has a negative value *to the utility*.(emphasis added) NorthWestern views its owned interest in Colstrip Unit 4 as a valuable component of its current electricity supply portfolio providing essential baseload electricity for its customers. With the addition of the Hydros, Colstrip Unit 4 will remain an integral component of a well-balanced portfolio of electricity supply resources that are part of a fully integrated set of utility resources (supply, transmission, and distribution).

In this case too, if the proposed acquisition is approved by the Commission, and if the hydros turn out to be an excessively costly resource, as CU4 has proven to be, they will nonetheless continue to have substantial value to the utility, as they will remain a large component of NWE's rate base, producing large profits for decades to come.

analysis add assumed carbon taxes of $13.45 per MWH (or a 31.4% increase) to the alternative cost of purchased power (without the carbon adder) beginning in 2021, it then proceeds to increase this carbon penalty by 5 percent in each year thereafter, even though all other costs in its analysis (including hydros' costs) increase by only 2.5 percent per year.

This hypothetical carbon tax assumption creates a huge assumed cost advantage for the hydros in future years and essentially drives the long term cost comparison. The federal government has made no decision as to the amount or timing of possible carbon tax penalties (if any), and in fact there remains considerable political disagreement about the adverse economic impact that would cause and whether such charges should be imposed.[9] In contrast, the Company's analysis presumes that the Commission will establish rates reflecting the imposition of a large hypothetical carbon tax adder on Montana ratepayers (beginning in 2014[10]), whether or not federal authorities ultimately decide to impose such a tax on all energy consumers.

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[9] While the Company's analysis treats its assumed carbon taxes as real cost, the EIA does not represent this carbon tax amount to be a projection or a forecast or even an assumption. Rather the EIA refers to this carbon cost amount in terms of a "hypothetical illustration" -- "hypothetical carbon dioxide (CO2) emission fees … [to] illustrate the impact of policies that might place an implicit or explicit value on CO2 emissions from fuel combustion." See U.S. Energy Information Administration "Further Sensitivity Analysis of Hypothetical Policies to Limit Energy-Related Carbon Dioxide Emissions" July, 2013.

[10] Carbon taxes become effective in NWE's modelling in 2021. However, under the Company's ratemaking proposal, that modelling justifies adding $900 million to the Company's rate base immediately. Thus, for ratemaking purposes, the effect of NWE's hypothetical carbon tax assumption on Montana ratepayers would be immediate upon the Commission's approval of NWE's proposal, and it would continue at a high rate for many years whether or not such taxes are ever implemented for energy consumers outside of Montana.

If federal authorities ultimately decide against implementing a large carbon tax because of its adverse economic impact, that decision may benefit energy consumers nationally by preserving lower cost power supplies and electricity rates. However, the large carbon tax cost levels presumed here by NWE (including escalation into the future) will remain for Montana ratepayers, as the Commission's approval of the hydros purchase at $900 million will have permanently embedded those assumed carbon tax penalty costs in NWE's rates for the long term future. The Commission will, itself, have effectively pre-approved this hypothetical "carbon tax" level, with the beneficiary being PPL.[11]

Q. HAS NWE BEEN CONSISTENT BY ALWAYS INCLUDING CO2 COSTS WHEN EVALUATING THE AVOIDED COSTS OF POWER SUPPLY ALTERNATIVES, SUCH AS THE COST OF PURCHASED POWER IN THIS CASE?

A. NWE does include CO2 cost assumptions in its resource planning. However, in considering the avoided costs of alternatives, as in the

[11] NWE's filing is remiss in not more candidly advising the Commission on the sensitivity of its analysis to the assumptions about carbon taxes. As MCC stated in its comments on NWE's procurement plan: "MCC notes with particular concern issues involving how the Procurement Plan evaluates the possible imposition of a CO2 tax, both because this has been a subject of much contentious debate and because it may have a significant impact on the outcome of the Procurement Plan. NWE has recognized in the past that a robust plan is one in which significant choices are relatively insensitive to changes in input assumptions and modeling methods. If the decision to purchase the PPL hydro assets is sensitive to the assumed level and imposition date of a CO2 tax, e.g., it is incumbent on NWE to explicitly evaluate that sensitivity and to explicitly evaluate the consequence of an unfortunate outcome or of a wrong choice. The 2013 Procurement Plan is deficient on this important issue." These comments apply even more directly to the proposed hydro purchase.

Company's most recent QF case, NWE has argued against the inclusion of presumed but speculative CO2 costs in avoided cost calculations. For example, in its reply brief dated November 13, 2012 in Docket No. D2012.1.3 NWE argued:

> Although it is prudent to consider the possibility of greenhouse gas costs in planning, it is not appropriate to include such costs in avoided costs. Currently, NorthWestern is not incurring any greenhouse gas costs and cannot avoid any such costs by purchasing electricity from Qualifying Facilities ("QFs"). Including such costs would violate the customer indifference requirement of the Public Utility Regulatory Policies Act of 1978. The Commission should reject Hydro/Solar's recommendation.

In this case, the Company's proposed $900 million rate base addition is justified primarily by very long term and speculative assumptions about greenhouse gas taxes that are not now and may never be a reality. As suggested in the Company's own argument in the QF case above, while it is not unreasonable to consider the risk of possible future CO2 costs, it would be prudent regulatory policy to defer the inclusion of these uncertain future costs in current rates until (if and when) these costs are actually implemented. This is one reason that I am suggesting a modified approval structure below.

A further problem with the Company's proposal, which is also dealt with in my modified compromise described below, is that it would impose huge additional costs on current ratepayers for at least the next eight years (i.e., a doubling of costs in the test year and $400 million of added costs over eight years) with the assumed possibility of some offsetting benefits for later generations of customers far in the future -- if the Company's hypothetical and speculative CO2 tax assumptions actually come to pass. This is known in regulation as an "intergenerational equity" problem, and, as here, it generally involves taxing current ratepayers in order to hopefully benefit future generations. In this case, the current costs are so great and the future benefits so distant and speculative that the proposed scheme (without the type of modifications that I suggest below) is extremely unfair to current ratepayers. As I will show below, approving NWE's proposed ratemaking for the hydro purchase would be directly equivalent to the PSC locking in NorthWestern's hypothetical future carbon taxes into customer rates beginning immediately and extending for the next 30 years for hydro generation that emits zero CO2.

Q. CAN IT BE ARGUED THAT THE COMPANY'S PROPOSAL SHOULD NEVERTHELESS BE APPROVED BECAUSE THIS LARGE ADDITIONAL COST IS WARRANTED AS A NECESSARY INDUCEMENT TO ENCOURAGE THE ACQUISITION OF CLEANER GENERATION RESOURCES?

A. While that type of argument may be given consideration in other circumstances, such as requiring the payment of a higher price to induce the development of wind generation, it does not apply in this case. The Commission's approval of NWE's proposal in this case would not result in the development of any new clean generation resources. NWE's ownership of the hydros will not benefit the Montana economy by encouraging new asset development (indeed, higher electricity costs may retard such development), and the environmental benefits of the hydros will be the same whether NWE or some other entity owns them. NWE's ownership of the hydros may mean that more of the hydros' output will be consumed by NWE's customers and less by others in the market, but then other merchant generation will be required to meet total market requirements. Total hydro generation and total gas-fired generation will likely remain the same whether or not NWE purchases the hydros, and there is likely to be very little change, if any, in environmental impacts whether NWE acquires the hydros or purchases generation from the market.

Q. OTHER THAN THE PRESUMED CARBON TAX ON COMPETITIVE MARKET PURCHASES, HAS THE COMPANY MADE OTHER ASSUMPTIONS THAT CONTROL ITS COMPARATIVE COST ANALYSIS?

A. Yes. In addition to the carbon tax adder, the Company's comparative cost analysis also ignores potentially substantial costs that could add significantly to the hydros' revenue requirements. Although PPLM's historic capital expenditures on the hydro plants have increased substantially as they have aged, NWE's comparative cost analysis presumes that when currently ongoing capital expenditure projects are completed in 2017, there will be no further large expenditure requirements for major repair, refurbishment and restoration projects as ongoing plant aging and wear and tear continues into the second century of these plants' lives. For example, although Rainbow Dam has recently gone through a $245 million power house replacement program, the Company's assumption is that no similarly costly projects (power house or otherwise) will be required at any of the other dams for the next thirty years. Instead, NWE assumes that capital expenditures will decline from an average of $35.6 million per year over the period 2008-2017 (actual for 2008-2012 and budgeted for 2013-2017), to a low projected value of $8.5 million in 2018 and then remain at that level (with only a small 2.5% annual inflation escalation) for the next three decades as these plants continue to age without any need for additional major restoration or repairs in the future.

Further, despite the age of these dams, NWE has assumed zero decommissioning and retirement costs for all of them in its projected cost comparison. Sellers in competitive markets must, of course, recover their anticipated plant retirement costs (often referred to as "negative salvage") in market prices. Since NWE is seeking the Commission's approval of this acquisition based on the assumption of zero decommissioning costs, the Company should stipulate that, as a condition for approval, it will agree to forego any attempt to recover additional decommissioning costs in the future and to forego any negative net salvage claims for these dams and their facilities in any future depreciation cost analysis.

Q. ARE THERE FURTHER PROBLEMS RELATED TO THE COMPANY'S STOCHASTIC ANALYSIS OF COMPARATIVE COSTS?

A. Yes. The Company's comparative cost analysis is further compromised because (in the stochastic cost version) NWE makes substantial cost-increasing adjustments for uncertainties regarding purchased power alternatives, but fails to recognize and account for certain substantial future hydro plant cost uncertainties, such as capital expenditure requirements, which are potentially far greater. As is shown below, modifying any of these assumptions so as to more evenhandedly assess comparative hydro and purchased power costs, makes the hydros alternative far more costly to Montana consumers and shifts the comparative balance far more in favor of competitive market purchases and significantly against the Company's ratemaking proposal for the hydros purchase alternative.

Q. IS IT POSSIBLE FOR THE COMPANY TO MAKE IMPROVEMENTS IN THE ECONOMIC ACCEPTABILITY OF PURCHASING THE HYDROS?

A. Yes; that may be possible, but it will depend upon the Company's willingness to make modifications to its proposal that will reduce the imposition of very excessive costs on today's consumers. After describing the major consumer impact problems with the Company's proposal I will describe three straight forward modifications that would substantially improve the proposal.

Q. IN ADDITION TO EVALUATING THE COMPARATIVE COST OF NWE'S PROPOSED HYDROELECTRIC PLANT ACQUISITION, WHAT OTHER ISSUE DOES YOUR TESTIMONY ADDRESS?

A. I also address the matter of NWE's common equity cost allowance ("ROE"). The Company proposes to finance the proposed acquisition of the hydros with 45 percent common equity capital and 55 percent long term debt. For ratemaking purposes they propose the use of 48 percent common equity ratio and a 52 percent debt ratio, which is similar to the 52.35% debt / 47.65% equity capital structure that was approved by the Commission in Docket No. D2012.9.94. The Company's requested ROE is 10.0 percent. My evaluation of the Company's ROE request, as presented below, indicates that the 10 percent ROE proposal is excessive. The claimed analysis supporting this ROE request is highly distorted by apparently arbitrary and extremely one-sided exclusions of comparable company data from the ROE calculations. Specifically, the Company's discounted cash flow ("DCF") analyses, which are presented by Mr. Bird, start with 114 calculated ROE values reflecting twenty-four comparable utility companies, each with five different growth estimates (in six instances no growth estimate was available), but of these 114 calculated values, thirty-seven were excluded from the analysis and from the computation of the comparable company averages. These thirty-seven excluded values were the thirty-six lowest calculated values and a single high value. There was no apparent reason for excluding the thirty-six lowest values from the ROE calculation other than they reduced the calculated average. As shown below, by restoring the excluded values or by engaging in a more balanced and reasonable exclusion procedure it is clear that a more sensible and less biased DCF ROE estimate is in the 8 to 9 percent range. Other methods for estimating NWE's required ROE further confirm that an allowance above the 8 to 9 percent range is unreasonable.

Also, as discussed below, in establishing an appropriate ROE allowance in this case the Commission must recognize that the Company's pre-approval proposal for the hydros purchase shifts virtually all normal business risks for this investment from NWE's stockholders to the Company's Montana ratepayers. Not only would current ratepayers be burdened with a hydro cost of service revenue requirement that is hundreds of millions of dollars more costly than alternative purchased power costs for many years, the significant and long term uncertainty regarding additional unknown future capital investment increases for project refurbishment and maintenance poses essentially zero risk for company stockholders. Particularly in light of all of these business risks that would be transferred from stockholders to ratepayers, there is no justification for the Company's proposed 10 percent ROE, which incorporates equity return allowances for entrepreneurial risk.

As I indicated above, after further discussing the major economic problems with the Company's hydros purchase proposal as presented by NWE in this case, I will suggest several modifications which, if accepted by NWE, would result in a degree of risk sharing between the Company and consumers. That may, in turn, render an ROE allowance of 10 percent a more accurate representation of compensation for risks actually retained by

NWE.

III. COMPARATIVE COST OF THE HYDROS

Q. HAVE YOU REVIEWED THE COMPANY'S COMPARATIVE COST ANALYSES?

A. Yes; I have. The Company has presented two types of cost comparisons which it calls "deterministic" and "stochastic." All of these comparisons indicate that the hydros acquisition will result in much higher costs for ratepayers than would projected competitive market purchases for at least the next decade. Over the much longer term, however, the Company's deterministic forecasted cost comparisons indicate that the present value of ratepayer costs will be only slightly greater with the hydros purchase, and the stochastic cost forecasts indicate that the hydros purchase could result in lower long term costs. The reason the stochastic results appear more favorable is that the stochastic model incorporates certain specified uncertainties or risk assumptions for key market purchase cost variables, such as the possible doubling of assumed CO2 cost penalties for fossil fuel generation and additional fuel cost uncertainties, which could make the hydros a lower cost alternative for future generations. The stochastic model also incorporates a highly speculative $1.68 billion cost offset for the hydros, reflecting assumed appreciation of these facilities over time instead of depreciation.[12]

Q. THE COMPANY APPEARS TO FAVOR THE STOCHASTIC RESULTS, WHICH PORTRAY THE HYDROS PURCHASE IN A MORE FAVORABLE LIGHT OVER THE LONG TERM. DO YOU AGREE THAT THE STOCHASTIC RESULTS OFFER THE BETTER FORECASTED COMPARISON OF THE HYDROS' COSTS VERSUS THE COMPETITIVE MARKET PURCHASE ALTERNATIVE?

A. Although there is merit to stochastic modeling, I consider the stochastic results here to be unreasonably biased in favor of the hydros, as they incorporate substantial risks for market purchase costs but no risks for very low assumed hydro capital expenditure levels – such as optimistic but uncertain long term renovation, retirement and rehabilitation expenditures for the aging hydro plants.[13] During the most recent 5-year historical

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[12] Note that despite this assumed $1.68 billion of appreciated value in its market valuation and cost comparison analyses, the Company requests to be compensated for plant depreciation in its proposed test year revenue requirement.

[13] MCC-054 asked the following:

> In reference to page JMS-39, lines 16-20: Please fully describe each unknown variation ("meaningful uncertainty") that you allowed for (and how you so-allowed) in the expected life and replacement cost of each element of the aging equipment and structures comprising the hydro generating facility units (and components thereof) in your probabilistic simulation process.

NWE's response was as follows:

> "Meaningful uncertainty" in the context of the referenced testimony and the PowerSimm modeling applies to the uncertainty of weather, load, hydro flows and the resulting generation output, and market prices, not physical equipment and structures of the hydro facilities or other generators.

period (2008 – 2012), actual capital expenditures on the hydros averaged $59.6 million per year. A substantial portion of the nearly $300 million in capital expenditures over this 5-year period was the cost of rebuilding the Rainbow Power House and structural repairs at Hebgen. NWE now forecasts no such major renovation or repair needs for any of the dams going forward over the next thirty years, but assumes instead, that annual capital expenditure requirements will be only $8.5 million per year (escalated at 2.5 percent for inflation). Even PPLM's budgeted capital expenditures over the next five years (2013-2017) average $11.6 million per year – well above NWE's corresponding assumption from 2018 forward.

It may be that no future repair projects as big as Rainbow are now foreseen or budgeted for specific dates in the future. And, while capital expenditures of only $8.5 million per year may be required in years with those fortunate circumstances, it would be extremely good fortune, given the age and history of these facilities, to achieve that result year-in and year-out, as the Company assumes, in every year over the next three decades as these plants move into their second century of operation. Indeed, there is not even a single year in the last ten when the actual or budgeted capital expenditure

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The probabilistic simulation process does not model the expected life and replacement cost of the physical components of either the Hydros or alternatives such as a combined cycle combustion turbine. The cost of potential future repairs and replacement parts are incorporated in the capital and operating cost forecasts for each resource type. See also the Prefiled Direct Testimony of William T. Rhoads on page WTR-12, line 13 through WTR-13, line 17.

total was as low as the $8.5 million amount that NWE assumes (with 2.5% inflation) for all future years. In the event that these dams, which are not going to get any younger as time goes on, continue to experience refurbishment costs in the future that are more in line with their past experience (and the probability that old facilities and equipment will require more, not less, refurbishment and replacement as they continue to age) the risk of incurring these additional costs will be the burden of Montana ratepayers (not NWE stockholders) as the future unfolds.

Q. IS IT ACKNOWLEDGED BY NWE THAT ACTUALLY REQUIRED FUTURE CAPITAL EXPENDITURES AND THE NEED FOR MAJOR CAPITAL PROJECTS IN THE FUTURE CANNOT NOW BE FORESEEN WITH ANY GREAT CERTAINTY?

A. Yes. MCC asked the Company's independent engineer numerous questions about issues that he had identified and about the potential future cost of repair. While specific estimates could be made in some cases, it was generally the case that the costs of potentially large future projects which are not known currently (and, according to the Company, none are), could not be reasonably estimated or known in advance. For example, in response to MCC-105, which asked what period of time and costs are likely for remedial measures that may be required to deal with concrete conditions at Mystic that now appear to be only "fair to good" (but not requiring *immediate* remedial measures) the response was:

> Timing of remedial measures for concrete of the upstream surface of the dam is not known and depends on the weathering effects on the structure. As stated in the report, "weathering … is continuing at a relatively slow rate" and "the arch dam and spillway are performing adequately and meet the requirements of the FERC guidelines." Estimated future cost of any remedial measures is unknown and would depend upon the extent and/or severity of issues that may occur.

Also with regard to Mystic, NWE's independent engineer observed that:

> *Mystic flow line is exposed to the environment and is susceptible to rock falls.* (Emphasis in original) The potential future cost is unknown since it would depend on the extent and/or severity of the event that may occur. This is not included in the post 2017 capital estimate. (See response to MCC-182)

Likewise, with respect to Black Eagle, NWE's independent engineer observed that:

> Black Eagle intake wall is leaking and may eventually need a buttress. The potential future cost is unknown since it would depend on the extent and/or severity of issues that may develop. This is a

> local and limited condition that has long been known and has exhibited limited change. It is routinely monitored and is considered manageable. This is not included in the post 2017 capital estimate. (See response to MCC-182)

The independent engineer further stated that it is likely that the Black Eagle dam will ultimately be included in the final boundary definition of the Anaconda Copper Mining and Refinery Superfund Site (See MCC-175), and that while there is concern for potential groundwater contamination at Black Eagle, the potential cost exposure is unknown (See MCC-179). NWE further stated in response to PSC-080 that potential Superfund Site related costs (as well as Thompson Falls contamination, shoreline erosion litigation and potential Endangered Species Act exposure related to migration of Arctic grayling) "were not included in the capital budget forecast because they relate to less certain, potential future environmental liabilities."[14]

More generally, in response to the question:

> Is it possible that unforeseen events could cause required annual capital expenditures to be significantly higher than $8.5 million per

[14] NWE did include a one-time $350,000 contingency in 2025 for potential Superfund exposure. (See PSC-031) The Company acknowledges that this is a rough estimate reflecting a very small fraction (.0045%) of a much larger ($100 million) estimated total exposure, based on the legal argument that other parties (ARCO/BP) are the successor to the truly responsible parties for this Superfund Site. (See PSC-080)

> year after 2017?

The Company's independent engineer agreed that:

> Unforeseen events are possible in a given future year, but not expected every year. (See MCC-181)

Q. ARE THESE STATEMENTS REPRESENTATIVE OF OTHER RESPONSES CONCERNING SPECIFIC IDENTIFIED POTENTIAL CONCERNS REGARDING EACH OF THE DAMS THAT NWE IS PROPOSING TO ACQUIRE IN THIS CASE?

A. Yes. The independent engineer's report (Exhibit WTR-2.1) identifies numerous issues of this nature that may involve significant future capital expenditures and dozens of Category 2 Potential Failure Modes ("PFM") concerning the twelve dams that NWE proposes to acquire. While these PFMs (even at the Category 2 level – Category 1 being the highest or worst) do not imply that dam failure is probable or likely, they generally mean that a potential problem is indicated and that regular monitoring and periodic inspection are therefore called for so that probable failure can be identified in advance and needed repair and rehabilitation steps can be taken before any actual failure occurs. While many such remedies, when called for, may be accomplished without massive expenditure, there are occasions (as evidenced by Hebgen and Rainbow in recent years) when needed repairs and refurbishment can be expensive. As the Company has observed (I think correctly) in response to numerous data requests, in many or most cases potential ultimate cost exposure cannot be accurately known years in advance. However, in my view it is unreasonable, if not foolish, to assume that over the next thirty years there will be no costly repairs (as there actually have been in recent years and as are common for old and aging facilities) in order to maintain and continue efficient operation of these aging "high hazard"[15] dams, many of which will be well over 100 years old during this projected time frame.

Q. HAVE YOU REVIEWED AND EVALUATED THE COMPANY'S DCF ANALYSIS THAT PURPORTS TO ESTIMATE THE APPROXIMATE VALUE THAT OTHER POTENTIAL BIDDERS MIGHT ATTRIBUTE TO THE HYDROS?

A. Yes; I have. The stated goal of NWE's DCF analysis, as presented by Company witness Stimatz, was to "develop an estimate of the value of the Hydros from a third party, merchant point of view … The purpose of the DCF analysis was to estimate what NorthWestern's competitors in the bidding process might, on average, see as the value of the Hydros…" (See

[15] According to the Montana Department of Natural Resources all twelve of the dams at issue in this case are classified as "high hazard". This "high hazard" classification does not indicate that the risk of dam failure is considered to be great or even probable at the present time. Rather, I understand that the "high hazard" designation means that if a failure of the dam were to occur, the potential consequences for personal safety and property loss would likely be great. Thus, it is required that these "high hazard" dams be monitored and inspected regularly so that appropriate repairs and remedies may be implemented if and when it is determined that the risk of failure is significant.

JMS-5). The result of the Company's DCF analysis was an estimated third party mid-range value for the hydros of about $826 million.

Q WHY IS IT OF INTEREST TO REVIEW THIS DCF ANALYSIS?

A. This DCF analysis was used by the Company to develop and support its bid for the hydros, when it was essentially dealing with PPL on behalf of Montana ratepayers. It is important to evaluate the model and its results because it cannot necessarily be assumed that NWE had great incentive to minimize the price bid if the resulting purchase price goes into the Company's rate base and increases stockholder profits on a preapproved basis.

Q. DO YOU AGREE THAT THE COMPANY'S DCF ANALYSIS REASONABLY DEMONSTRATES THAT AN ALTERNATIVE MERCHANT GENERATOR WOULD BE WILLING TO PAY $826 MILLION FOR THESE FACILITIES?

A. No. Most importantly in this regard, the Company's DCF analysis includes $247.4 million of assumed hypothetical capitalized CO2 tax costs in the $826 million amount. These are not costs that an alternative competitive buyer (even one who believed these hypothetical taxes would occur) would be able to pass on to customers in competitive markets until (when and if) such assumed hypothetical carbon taxes were actually implemented.

Competitive markets, unburdened by such hypothetical taxes, would not permit such charges. As shown in Exhibit JW-1, without the Company's hypothetical carbon tax assumption, the result of the Company's DCF model would be a valuation of $578.5 million instead of $826 million.

Q. HOW DOES NWE'S RATEMAKING PROPOSAL IN THIS CASE DEAL WITH HYPOTHETICAL FUTURE CARBON TAX COSTS?

A. In contrast to the way that competitive markets work, NWE's proposal in this case is to include similar hypothetical future carbon taxes in its rate base and in the rates that Commission approval would force current ratepayers to pay immediately. An alternative merchant buyer of these plants would simply not be able to coerce such excessive advance payments from customers in competitive markets. Instead, in order to fund an $826 million purchase a merchant generator would have to find investors who were willing to finance the $247.4 million of hypothetical CO2 costs (that are included in the $826 million price) until such time that (when and if) those costs became real and were recoverable in the market.

Q. WOULD IT BE APPROPRIATE FOR NWE TO FOLLOW THAT FUNDING APPROACH RATHER THAN INCLUDING THIS HYPOTHETICAL COST LOADING IN RATE BASE?

A. Yes. It would be appropriate for NWE to obtain non-ratebase investor funding to finance the hypothetical CO2 tax costs (approximately $350 million) that are included in NWE's proposed $900 million purchase price. The alternative proposed here by NWE, to require today's Montana ratepayers to subsidize this financing by including hypothetical future CO2 tax costs in rate base, would be extremely unfair and excessively burdensome to Montana consumers.

Q. ARE THERE OTHER PROBLEMS WITH THE COMPANY'S DCF VALUATION ANALYSIS?

A. Yes. Another doubtful feature of the Company's DCF valuation analysis is its premise that a competitive buyer would value these plants by assuming that annual capital expenditures to keep the plants running and safe would be only $8.5 million annually for several decades, when PPLM's own actual and budgeted capital expenditures over the last ten years (2008-2017) reflect an annual average of $35.6 million. As shown in Exhibit JW-2, even if one were to assume that an alternative buyer would expect future capital expenditures to be half that historical level, the DCF value would be $512 million rather than $826 million if a competitive buyer was unwilling to assume the risk of funding the $247.4 million of hypothetical CO2 costs embedded in NWE's DCF analysis.

Also, despite the continued aging of these plants over the next twenty years and the assumption of diminished capital expenditures for their refurbishment, renovation and repair over that period, NWE's DCF analysis assumes that the plants will have a terminal market value (i.e., could be sold for) $1.1 billion in 2033. While I place little importance on such distant speculation, this one is worth noting, both because of its doubtful plausibility and because it is a critical factor in NWE's DCF market value estimate, accounting for $270 million of the Company's $826 million valuation.

Q. HAVE YOU ALSO REVIEWED AND EVALUATED THE COMPANY'S COMPARISONS BETWEEN ITS PROJECTED COSTS OF ACQUIRING AND OPERATING THE DAMS AS OPPOSED TO ITS ALTERNATIVE PROJECTED COSTS OF OBTAINING THE SAME ELECTRICITY PRODUCTION FROM COMPETITIVE MARKET SOURCES?

A. Yes; I have, and I have prepared several additional cost comparisons.

Q. PLEASE EXPLAIN YOUR EVALUATION OF THE COMPANY'S COST COMPARISONS AND THE ADDITIONAL COST COMPARISONS THAT YOU HAVE PREPARED.

A. The Company's cost or required revenue comparison, as presented in Exhibit TEM-2, projects the following alternative costs for the hydros and for market purchases to be paid by Montana consumers over the next eight years:

Year	Hydros' Costs (Thousands)	Competitive Market Costs (Thousands)
2014	$131,056	$61,826
2015	$128,686	$65,044
2016	$139,434	$76,003
2017	$139,158	$77,657
2018	$137,868	$82,177
2019	$137,242	$89,495
2020	$136,020	$97,672
2021	$136,043	$133,683
Total	**$1,085,507**	**$683,557**

Over these eight years the Company's own estimated revenue requirement for the hydros is $402 million greater than the alternative cost of competitive market purchases. This is surely not a matter of customer indifference for today's customers or of least cost planning for these current customers.

Q. THE DIFFERENCE SHOWN IN THE TABLE ABOVE DECLINES SUBSTANTIALLY IN 2021. DOES THAT APPARENT COST REVERSAL CONTINUE IN THE MORE DISTANT FUTURE IN THE COMPANY'S FORECASTS?

A. Yes. After 2021 the Company's projections continue to show substantial increases in competitive market costs and declines in the hydros' forecasted costs, so that over 30 years the projected net present value of the hydros' costs is only about $31 million greater than the comparative net present value of competitive market purchases ($1,658 million versus $1,627 million). In other words, if the Company's forecasts are right, today's consumers would pay $400 million more than competitive market costs for their electricity, and a large part of this would be made up on a present value basis by attaining lower power costs for future generations of ratepayers. If the Company's forecasts turn out to be mistaken or overly optimistic, today's ratepayers would still be overcharged by hundreds of millions of dollars, but the presumed offsetting benefits for future generations of ratepayers could disappear.

Q. WHAT ACCOUNTS FOR THIS REVERSAL IN THE COMPANY'S PROJECTED COSTS?

A. There are two factors that account for this projected long-term cost reversal. First, NWE assumes that very large hypothetical carbon tax penalties will be imposed for competitive market purchases in 2021 ($13.45/Mwh) and that these penalties will then proceed to increase by 5 percent in each following year, while the hydros' costs increase by only 2.5 percent per year. The Company's analysis assumes that total carbon tax penalties for the competitive market purchased power alternative will be $1.375 billion over the period 2021-2043. This $1.375 billion of hypothetical added carbon taxes is used to justify charging the equivalent cost of the hydros to Montana consumers over the period 2014-2043.

Second, NWE assumes that the hydros' capital expenditure requirements going forward will be only $8.5 million per year as compared with average annual capital expenditure amounts of $35.6 million from 2008 through 2017. Without these assumptions of very low future capital expenditure needs for the hydros and the addition of very substantial carbon tax penalties for market purchases, the cost advantage of market purchases would continue to increase very substantially after 2021.

Q. HAVE YOU PREPARED EXHIBITS THAT SHOW COST COMPARISONS BETWEEN PROJECTED HYDROS COSTS AND COMPETITIVE MARKET PURCHASE COSTS OVER THE FULL THIRTY YEAR PERIOD WITH MODIFIED ASSUMPTIONS?

A. Yes; I have. I would first caution that very long term projections are typically highly unreliable. However, because NWE's own financial justification for its proposed hydros purchase rests largely on such long term projections, I am providing alternative projections based on modified assumptions regarding the timing and rate of escalation for carbon tax penalties and for future capital expenditure requirements. Otherwise, I use NWE's projections for market purchases. This will permit the Commission to consider a more even-handed comparison if it chooses to rely upon such distant forecasts.

Q. PLEASE DESCRIBE YOUR ALTERNATIVE COMPARATIVE COST EXHIBITS.

A. I have prepared Exhibit JW-3 to further demonstrate the significance of NWE's carbon tax assumptions to the hydros vs. market purchases cost comparisons. In Exhibit JW-3 I have assumed that NWE's hypothetical carbon taxes are implemented in 2031, rather than in 2021, at $14.47 per Mwh, which reflects the same initial hypothetical tax rate assumed by

NWE but a cost escalation rate of 2.5 percent per year from 2014. I further assume that these hypothetical carbon taxes will continue to escalate from that date forward at the same annual rate of 2.5 percent per year. This is the same rate of escalation that NWE assumes for other costs – except for hypothetical carbon taxes, for which NWE's assumes that the cost escalation rate is double. Projected annual revenue requirements for the hydros and for market purchases are shown on lines 34 and 38, respectively, of Exhibit JW-3. As can be seen in the exhibit, there is a large cost advantage for competitive market purchases in each year that only begins to dissipate after carbon penalties kick in. In this case, the total cost advantage for market purchases from 2014 to 2030 is $615 million.

Q. IN EXHIBIT JW-3 YOU HAVE STARTED WITH THE SAME HYPOTHETICAL CARBON TAX RATE IN 2014 THAT NWE ASSUMED IN ITS ANALYSIS, BUT YOU HAVE CHANGED THE ASSUMED RATE OF ESCALATION. ISN'T THE CARBON TAX RATE AND THE ESCALATION RATE USED BY NWE THE OFFICIAL GOVERNMENT ("EIA") FORECAST?

A. No. EIA does not represent this carbon tax amount or the escalation rate to be a projection, a forecast or even an assumption. Rather the EIA refers to this carbon cost amount and the escalation in terms of a "hypothetical illustration" **--** "hypothetical carbon dioxide (CO_2) emission fees … [to]

illustrate the impact of policies that might place an implicit or explicit value on CO_2 emissions from fuel combustion."[16] As the Commission is aware, there is considerable controversy over carbon taxes and the impact that such taxes may have on the economy. Consequently, the hypothetical carbon taxes assumed by the Company and as reflected in Exhibit JW-3 may never be implemented or may be implemented at different rates or at a later time. If any of these things occur, the comparative cost of acquiring the hydros versus the alternative cost of competitive market purchases will be even higher and more costly to consumers than is suggested here because the Commission's approval will lock NWE's hypothetical carbon taxes into current rates and for the long term future.

Q. PLEASE DESCRIBE EXHIBIT JW-4.

A. In Exhibit JW-4 I make the same carbon tax assumptions as in Exhibit JW-3, and I also assume a single substantial capital expenditure project comparable to the Rainbow project, commencing a decade from now and spread over three years from 2024 to 2026. That, of course, increases the hydros' comparative costs substantially and further expands the cost advantage of alternative competitive market purchases. Again, projected annual cost amounts for the hydros and for competitive market purchases can be seen on lines 34 and 38, respectively, of the exhibit. Here the total

[16] See U.S. Energy Information Administration "Further Sensitivity Analysis of Hypothetical Policies to Limit Energy-Related Carbon Dioxide Emissions" July, 2013.

comparative cost advantage for competitive market purchases over the first seventeen years (2014-2030) is $808 million.

It should be stressed that, like NWE's projections, the alternatives shown in Exhibits JW-3 and JW-4 are not factual; rather, they simply reflect alternative and possibly more realistic assumptions regarding carbon taxes and future capital expenditure requirements. I have no knowledge that carbon taxes will actually be implemented in 2031 or ever at this high level, nor do I know that future capital expenditure requirements will include only one major renovation project for these 12 aging dams (11 after Kerr is sold) and their facilities over the next thirty years as they move into their second century of operation. If carbon taxes are not implemented (or if they are implemented at a lower level or at a later date) or if future capital expenditure needs for the hydros more nearly reflect actual capital expenditures and budgets over the 2008-2017 period, the cost advantage for competitive market purchases will prove to be considerably greater than is depicted here. It is clear that NorthWestern has assumed an optimistically low level of future capital expenditures, and the risk of higher costs is clearly something that needs to be incorporated into a reasonable evaluation.

Q. HOW MIGHT APPROVAL OF THE PROPOSED HYDROS PURCHASE BE JUSTIFIED?

A. In order to justify approval of the proposed hydros purchase, it is apparent that the Commission must determine at least three things:

(1) that it is appropriate to charge today's Montana electricity consumers hundreds of millions of dollars more than the alternative competitive market prices that would otherwise be expected for their power consumption over the next decade,

(2) that there is great faith in NWE's very long term projections (including drastically diminished future capital expenditure needs for these aging plants) which overcomes the hydros' admittedly much higher costs over the next decade, and

(3) that it is good public policy to implement electricity charges for Montana ratepayers that irrevocably reflect large hypothetical carbon taxes for consumers in this state, beginning immediately,[17] even though such taxes have not yet actually been implemented and may not be implemented for years, if ever, for energy consumers elsewhere in the country.

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[17] Carbon taxes are assumed to become effective in NWE's modelling in 2021. However, that modelling is the Company's asserted basis for adding $900 million to its rate base immediately. Thus, for ratemaking purposes, the effect of the carbon tax on Montana ratepayers would be immediate upon the Commission's approval of NWE's proposal.

Q. ARE THERE WAYS IN WHICH THE HYDROS PURCHASE MIGHT BE MADE COMPARATIVELY LESS COSTLY TO MONTANA RATEPAYERS?

A. Yes. I have already suggested that since the Company has assumed zero decommissioning costs for the hydros in its comparative cost analysis (in fact, NWE has assumed a positive terminal value (i.e., positive net salvage) of $1.1 billion for these plants in its DCF analysis and $1.68 billion in its stochastic analysis), NWE should guarantee that ratepayers will be held harmless for any such costs in the future and that no negative net salvage will be proposed or requested for these plants in the future. Also, the test year revenue requirement in this and future cases should be adjusted to reflect the terminal value of the hydro plants that is assumed by NWE in its comparative cost analyses.

Second, given that NWE proposes approval of the hydros acquisition based on the assumption that future capital expenditure requirements will not exceed $8.5 million per year (escalated at 2.5 percent), it would be eminently reasonable for the Company to agree to forego any recovery of or return on any future capital expenditures exceeding an annual average of $10 million (escalated at 2.5 percent). In the event that the annual average in any year exceeds $10 million, any excess could be "banked" for future recovery if and when the annual average drops below $10 million.

Third, there should be no recovery of hypothetical carbon tax amounts until CO2 taxes are actually implemented. To approximate this, the present value of hypothetical carbon taxes reflected in TEM-2 should be deducted from the authorized rate base amount for these dams and the recovery of such taxes should be deferred until carbon taxes are actually enacted.[18] The resulting revenue reduction can then be treated as a deferral and it can be added back to rate base (along with the original deduction and carrying costs) if and when carbon taxes equal to the hypothetical amount assumed in TEM-2 are actually implemented.[19]

To the extent that the Company resists these modifications it is reasonable to assume that NWE's comparative cost analysis unreasonably understates actual expected hydros' costs and/or unreasonably overstates alternative competitive market costs. That is so because the Company's comparative cost analysis (1) assumes zero decommissioning costs and asset appreciation – the same as proposed here, (2) assumes only $8.5 million of average annual capital expenditures – $1.5 million less than proposed here, and (3) the proposal here would permit the full recovery of actual carbon taxes up to the total amount reflected in NWE's analysis.

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[18] I estimate that the amount of carbon taxes included in NWE's assumed alternative competitive market costs in TEM-2 for the period 2021-2043 is $1.375 billion. The present value of this total at 2014 is $353.7 million.

[19] In the event that carbon taxes of a lesser amount than is assumed in Exhibit TEM-2 are eventually implemented, and/or to the extent that actual carbon tax enactment occurs at a later date, the deferred ad-back (and original deduction) should be adjusted so that the present value of carbon tax recovery does not exceed the present value of carbon taxes actually implemented.

IV. RETURN ON EQUITY

Q. WHAT IS THE RETURN ON COMMON EQUITY CAPITAL ("ROE") THAT YOU RECOMMEND THE COMMISSION AUTHORIZE IN THIS CASE?

A. My recommended ROE in this case is 9.0 percent. Assuming that the Commission elects to approve the proposed hydro purchase despite its substantially higher comparative costs and open ended long term capital expenditure risks for Montana consumers, this is at the high end of a reasonable rate of return range in this proceeding.

Q. PLEASE EXPLAIN THE BASIS OF THIS ROE RECOMMENDATION.

A. As noted above, the Company's requested ROE is 10.0 percent. The analysis supporting this ROE request is highly distorted by apparently arbitrary and extremely one-sided exclusion of comparable company data from the ROE calculation. Specifically, the Company's discounted cash flow ("DCF") analyses, which are presented by Mr. Bird, start with 114 calculated ROE values reflecting twenty-four comparable companies, each with five different growth estimates (in six instances no growth estimate was available), but of these 114 calculated values, thirty-seven were excluded from the analysis and from the computation of the comparable company averages. The results of the Company's analysis are shown on page 1 of Exhibit JW-5. Out of the thirty-seven excluded values indicated there are the thirty-six lowest calculated values and a single high value. There was no apparent reason for excluding the thirty-six lowest values other than they reduced the calculated average.

On page 2 of Exhibit JW-5 I have restored all of the excluded values, and we see that the calculated DCF results now indicate a cost of common equity capital in the 8 to 9 percent range. Similarly on page 3 of Exhibit JW-5, I have excluded the two high value outliers and eleven low values that are under 6 percent. Despite the fact that I have excluded far more low values than high values, the end result continues to indicate a cost of common equity capital in the 8 to 9 percent range. Also, all of the remaining results shown on page 3 of Exhibit JW-5 are more than 150 basis points above the cost of debt that the Company is seeking in this case.[20]

[20] I note that the FERC, which sometimes uses this type of DCF analysis with the exclusion of high value and low value outliers, typically limits low value exclusions to those that are less than 100 basis points above the cost of long term debt.

Q. EARLIER YOU SAID THAT OTHER METHODS FOR ESTIMATING NWE'S REQUIRED ROE FURTHER CONFIRM THAT AN ALLOWANCE ABOVE THE 8 TO 9 PERCENT RANGE IS UNREASONABLE. WOULD YOU PLEASE EXPLAIN THOSE OTHER METHODS?

A. The other methods that I have considered include the capital asset pricing model ("CAPM") and comparable company expected earnings. These are similar to the additional models that Mr. Bird considered. However, Mr. Bird's CAPM evaluation mistakenly uses long term bond rates as a measure of "risk-free" return, and his expected earnings results are presented without adjusting for the difference between return on market value and return on book value of an alternative investment. Comparable returns available to common stock investors are returns on the market value of a stock investment – not the return on book value. If, as is typically the case, the market value of a share of stock is higher than its book value because, say, market price has been bid up to $15 when the stock's book value is $10, an expected return of $1.00 will provide an investor who buys the stock at market value with a return of 6.7 percent – not a 10 percent return. In that case, the comparable earnings rate that must be considered when contemplating alternative investments is 6.7 percent.

Likewise, when adding a risk premium to the risk-free rate in CAPM analysis, one must use the interest rate on very short term Treasury debt as the risk-free rate. That is so because the interest rate on long term bonds includes substantial premium for the interest rate risk associated with locked-in return levels and for the currency fluctuation risk of long term dollar denominated repayment.

It is clear that long term debt to be repaid in 20-30 years in the future is not "risk free." Even long term U.S. Treasury debt has three widely recognized risks: 1) default; 2) changes in currency exchange rates and 3) interest rate changes. The potential of default risk for U.S. debt has been widely acknowledged, and the financial community is well aware of it. The recent downgrading of U.S. debt was an explicit and undeniable recognition of its long term default risk. Second, repayment of U.S. Treasury debt in thirty years will be in U.S. dollars, and it is certain that exchange rates between dollars and other currencies will vary significantly over the long term. Consequently, long term Treasury debt has substantial currency devaluation risk.

Third, there is substantial risk of interest rate changes over time. Indeed, the simple fact the interest rate on long term debt is several times the interest rate on short term debt is a clear illustration that long term debt is, in fact, viewed by investors as higher risk than short term debt. Even mortgage lenders recognize this “time” risk as effective rates on 30 year mortgages are typically higher than on shorter term mortgages.

To illustrate that interest rate risk adds substantially to default risk, assume that an investment of $1,000 for thirty years at 3% interest entitles an investor to a return of $30 per year plus recovery of the $1,000 initial investment at the end of thirty years. If interest rates were to increase to 6% (still well below what they were years ago), an investor who locked into a 30 year bond at 3% a year earlier would lose an enormous amount of money, as his annual return of $30 is only half of the $60 annual return he could have had by investing short term for a year until the interest rate increase occurred. Thus, the total return (interest plus principal) on long term Treasury bonds, held to maturity, is obviously not “risk free” if unforeseen interest rate changes can cause investors to lose a large part of the potential 30 year total return. This increase in rates is not simply a missed opportunity but a loss of value as the increased rates indicate that inflation has risen and the purchasing power of the investment and the return on that investment has declined.

Because Mr. Bird used long term bonds in his CAPM evaluations, he overstated the correct result by about 300 basis points. Using a reasonable risk premium of 3 to 6 percent over the current cost of risk free debt, a corresponding CAPM cost of equity estimate would be less than 8 percent at the present time.

Q. PLEASE EXPLAIN THE COMPARABLE COMPANY EXPECTED EARNINGS ANALYSIS THAT YOU CONSIDERED.

A. I have examined the rates of return that Value Line projects to be earned on common equity capital for Mr. Bird's comparable utilities. I have also examined the corresponding market prices that Value Line projects for common stock of those same companies. The implied cost of equity capital is the projected return on book value divided by the projected market/book ratio.

Q. WHAT IS A MARKET/BOOK RATIO AND WHY IS IT RELEVANT IN DETERMINING A FAIR COMMON EQUITY RETURN ALLOWANCE?

A. A market/book ratio is the relationship that exists at any time between the market value that investors place on a firm's common stock and the stock's book value. If regulators allow utilities to earn ROEs that equal the cost of obtaining capital in the marketplace, then market forces will tend to drive the prices of common stock toward their book value. If the expected return exceeds the required return, the price of common stock will be greater than the stock's book value. If the expected return is lower than investor requirements, the market price will tend to fall below book value. If investor expectations and requirements are the same, the stock will tend to trade at a price equal to book value.

Q. IS THIS AN IMPORTANT CONSIDERATION IN RATE REGULATION?

A. Yes. It is an important consideration in rate regulation. If the market price of common stock rises to and remains at a level that is substantially in excess of book value, that is a clear signal that investors' earnings expectations as a percentage of book value exceed the cost of capital, and that investors have capitalized these expected excess earnings by bidding up the price of common stock to a level greater than the stock's book value.

Thus, for example, if an investor purchases common shares at a market price equal to 1.5 times the stock's book value and the company earns a 15 percent rate of return on book value, the investor actually realizes a smaller return (i.e., 10 percent) on the market value of his or her investment. Since 15 percent exceeds the return that is required in the marketplace (we know that because, in this example, with a 15 percent return investors bid the stock price up to 150 percent of its book value), the 15 percent return on book value is capitalized (i.e., built into the discounted present value of the security) by investors, thus inflating the market price of stock. While this may result in gains for original stockholders who paid book value for their holdings, the excess return is an unnecessary expense for ratepayers if it is reflected in allowed rates. Since it is both excessive and unnecessary, this condition should be avoided under effective rate regulation. Of course, temporary fluctuations and short-term cycles affect prices, and a stock price varies from its trend over time. This means that if common equity costs remain about the same over time, and if investors expect future returns equal to the market cost of equity, the price of stock will fluctuate within a reasonably narrow range of book value.

Q. IS THERE EVIDENCE AS TO WHAT RETURN ON EQUITY CAPITAL IS EXPECTED TO PRODUCE A MARKET-TO-BOOK RATIO OF 1.0 IN THE ELECTRIC UTILITY INDUSTRY IN THE FUTURE?

A. Yes. The Value Line Investment Survey has published projected market-to-book ratios for comparable gas and electric utility companies in recent issues. These are summarized for Mr. Bird's comparable utilities in Exhibit JW-6. As shown in this Exhibit, it is projected that an average expected return on the book value of common equity of 9.4 percent for Mr. Bird's comparable utility companies will produce an average market-to-book ratio of 1.28 times. This, in turn, implies an average cost of common equity capital for these companies of 7.4 percent.

A market price equal to book value indicates that investors expect future earnings rates equal to their required return or cost of capital. To the extent that investors expect that the rate of return earned on the book value of assets will exceed the required return or cost of capital, there will be a tendency to bid up the market value of stocks to the level at which the expected return in relation to market value equals the required return or cost of capital. Thus, if the required return or cost of capital is 8 percent, but investors expect that a 12 percent return will be earned on book value, market prices will be bid up to 1.5 times book value so that the realized return equals the cost of capital (i.e., 8 percent). The implication in this case is that an equity return of 7.4 per cent would be sufficient to sustain the stock price at book value, i.e.

$$9.4\% / 1.28 = 7.4\%.$$

Q. WHAT CAPITAL STRUCTURE SHOULD THE COMMISSION ADOPT IN SETTING THE OVERALL RATE OF RETURN ON RATE BASE IN THIS CASE?

A. NWE plans to finance the hydros acquisition using 55 percent debt capital at an annual cost rate of 4.5 percent and 45 percent equity capital. I believe this is the appropriate capital structure that should be adopted in setting rates in this case.

Q. A 45/55 EQUITY DEBT RATIO WOULD BE SLIGHTLY DIFFERENT THAN THE 48/52 CAPITAL STRUCTURE THAT NWE PROPOSES AND WHICH THE COMMISSION HAS ALLOWED IN OTHER RECENT CASES. WHAT WARRANTS THIS CHANGE?

A. The slightly lower equity ratio that I recommend will provide ratepayers with a small cost reduction and it will be more in line with the specific risk conditions in this case. As I have already discussed, the Company's proposal here would shift virtually all equity investment risks from stockholders to ratepayers. In addition, the Company acknowledges that the proposed transaction will provide other financial benefits to NorthWestern in many ways, including improved earnings, size, scale, and cash flow, which will all improve the Company's credit quality. Also, according to NWE, the hydros acquisition "will reduce reliance on Power Purchase Agreements, which are viewed as quasi-debt by the rating agencies." (See BBB-40 at 20-21) Consequently, although NWE was previously allowed a 47.65/52.35 equity/debt ratio for ratemaking, that ratio did not reflect or account for the quasi-debt nature of Power Purchase Agreements. Recognizing that these agreements are viewed as quasi-debt by rating agencies would result in a pro-forma debt ratio well above 55 percent. This, taken together with the other credit quality enhancements of this proposed acquisition, the very low level of investor risk associated with it and its proposed actual financing with 45 percent equity and 55 percent debt clearly justifies the use of that same equity/debt ratio for ratemaking. To instead use a capital structure comprised of 48 percent equity and 52 percent debt for ratemaking in this case would provide the Company with an equity return on a portion of rate base that is actually financed with much lower cost debt.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN THIS CASE.

A. NWE is requesting the Commission's authorization to raise electric rates for Montana consumers to pay for its proposed acquisition of PPLM's hydroelectric plants. The Company's own comparative cost analysis shows that the Company's ratemaking proposal would result in additional costs to Montana ratepayers of $400 million (above the Company's own estimate of equivalent competitive market purchase costs) over the next eight years.

While this cost increase is substantial, it is based on highly questionable assumptions which, if not realized, would result in an even greater cost disadvantage for ratepayers. Specifically, the Company's analysis assumes the imposition of $1.375 billion of hypothetical carbon taxes on competitive market purchases and it also assumes that required capital expenditures for the hydros will decrease to only about 25 percent of the actual average and budgeted capital expenditure level over the most recent ten year period 2008-2017. If these two speculative assumptions do not occur and the Commission approves NWE's ratemaking proposal for the hydros purchase, the resulting cost increase for Montana ratepayers will be $600 million to $800 million, or even more, above the Company's alternative expected competitive market wholesale power costs over the period 2014-2030.

This cost increase amounts to approximately $600 to $800 for every man woman and child in Montana, and it is money that will be extracted from the State's economy – not money that will be recirculated within Montana. It will first be capitalized in a $900 million lump sum amount that will be paid out to PPL. That amount plus interest and return on equity will then be recovered in rates from Montana consumers over the next 30 years and will be paid out over that time to NWE's lenders and stockholders who financed the $900 million lump sum payment to PPL.[21]

[21] Since the plant purchase cost is proposed to be amortized over 40 years, the capital expenditure recovery from Montana ratepayers over the next 30 years will be $763 million (inclusive of the $900 million purchase price and assumed subsequent capital expenditures). In addition, over these next 30 years the Company's ratemaking proposal would charge Montana ratepayers an additional $796 million for stockholders' return on equity plus an additional $486 million for increased income taxes and $388 million for additional interest. Thus, the Company's ratemaking proposal for the hydros acquisition will add $2.434 billion of capital cost recovery plus interest and pretax ROE costs for Montana ratepayers over the next thirty years, assuming that future capital expenditures are actually limited to only $8.5

In order to moderate this very adverse ratepayer impact I have suggested three modifications that the Company should endorse in seeking Commission approval of the hydros purchase:

1. NWE should guarantee that ratepayers will be held harmless for any decommissioning costs in the future and that no negative net salvage will be proposed or requested for these plants in future depreciation cost studies. Also, the test year revenue requirement in this and future cases should be adjusted to reflect the terminal value of the hydro plants that is reflected in the Company's comparative cost analyses. This is a reasonable condition as the Company has assumed zero decommissioning costs for the hydros in its comparative cost analysis, and it has assumed a positive $1.1 billion terminal value (positive net salvage) in its DCF estimate of market value and $1.68 billion in its stochastic cost comparison.

2. NWE should agree to forego any recovery of or return on any future hydro plant capital expenditures (above the proposed $900 million purchase cost) exceeding an annual average of $10 million (escalated at 2.5 percent). In the event that the annual

million per year (escalated at 2.5%) as assumed by NWE. The corresponding cost of equivalent market purchases over this 30 year period, excluding hypothetical CO2 taxes, would be more than a billion dollars less.

average exceeds $10 million (escalated), any excess could be "banked" for future recovery if and when the annual average drops below $10 million (escalated). This is a generous condition as NWE proposes approval of it ratemaking proposal for the hydros acquisition based on the assumption that future capital expenditure requirements will not exceed an annual average of $8.5 million per year (escalated at 2.5 percent).

3. NWE should agree that no hypothetical carbon tax amounts will be reflected in ratepayer charges until such time as CO2 taxes are actually implemented. To achieve this result, the present value of carbon taxes reflected in TEM-2 should be deducted from the authorized rate base amount for the dams and the recovery of CO2 tax amounts from ratepayers should be deferred until carbon taxes are actually enacted. The resulting revenue reduction can then be treated as a deferral and it can be added back to rate base (along with the original deduction and carrying costs) if and when carbon taxes equal to the amount assumed in TEM-2 are actually implemented. In the event that carbon taxes of a lesser amount than is assumed in Exhibit TEM-2 are eventually implemented, and/or to the extent that actual carbon tax enactment occurs at a later date, the deferred ad-back (and

original deduction) would be adjusted accordingly so that the present value of carbon tax recovery does not exceed the present value of carbon taxes actually implemented.[22]

To the extent that the Company resists these modifications it is reasonable to conclude that NWE's comparative cost analysis unreasonably understates actual expected hydros' costs and/or unreasonably overstates alternative competitive market costs. That is so because the Company's comparative cost analysis (1) assumes zero decommissioning costs and asset appreciation – the same as proposed here, (2) assumes only $8.5 million of average annual capital expenditures – $1.5 million less than proposed here, and (3) the proposal here would permit the complete recovery of actual carbon tax amounts up to the full amount reflected in NWE's comparative cost analysis.

Of these three modifications, the third is the most important as without it there is the possibility of adding $1.375 billion of non-existent CO2 tax

[22] An important purpose of public utility regulation is to emulate the discipline and end results that would likely occur in a competitive unregulated market. The adoption of this condition would make the proposed acquisition more closely achieve that economic goal. For example, if competitive alternatives are priced at "X", that price will limit the price that any competitor can charge in the market. If a competitor believes that future costs will increase by $800 million, he cannot simply start to charge consumers X+$800 million now, but must wait until (when and if) his expected cost increase actually occurs and market conditions permit that price. If he believes strongly that the $800 million cost increase will occur soon and that he can avoid that increase by spending only $400 million now, he may elect to make that investment and capitalize it with the expectation of recovering it later when and if costs increase and competition permits higher prices. However, he cannot force consumers to assume and fund this entrepreneurial role unless he has a market regulator with coercive power who will impose prices far above those that a competitive market would allow – the very antithesis of the fundamental purpose of public utility regulation.

costs to charges that will be levied on Montana consumers. It is inconceivable that such a large extraction of wealth from Montana households, without the actual imposition of such a tax, would be in the public interest.

Finally, it is my recommendation that the Company's allowed ROE should not exceed a maximum of 9.0 percent and that the capital structure adopted for ratemaking in this case should be 45 percent equity and 55 percent debt. The Company's analysis supporting its request for a 10 percent ROE is severely distorted by many one-sided calculation adjustments and data exclusions that engineer a biased and unreasonably high end result. It is also based on the false presumption that the proposed hydros investment involves significant investor risk. Also, the Company's proposed capital structure does not reflect the proposed capitalization of the hydros acquisition, which is 55 percent debt and 45 percent equity. Nor does it account for the quasi-debt nature of pre-acquisition Power Purchase Agreements that result in a pre-acquisition pro-forma debt ratio well above 55 percent. This, together with the other credit quality enhancements of the hydros acquisition, clearly support a ratemaking capital structure with no more than 45 percent common equity.

As I have indicated, if the Company accepts the three consumer protection modifications suggested above concerning decommissioning costs, future capital expenditures exceeding $10 million per year and the rate base phase-in of amounts reflecting assumed hypothetical CO2 tax penalties, that would result in the more equitable treatment of current ratepayers. It would also be appropriate to renegotiate a more acceptable price with PPL. Otherwise, approval of the Company's ratemaking proposal for the hydros acquisition would impose an unnecessary and unacceptable rate level penalty of at least $400 million above competitive market costs on current Montana ratepayers. Acceptance of these modifications would also result in a more reasonable sharing of risks with ratepayers and may therefore justify a 10 percent ROE allowance and the use of a 52/48 capital structure for ratemaking.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Exhibit JW-1

D2013.12.85

Exhibit__(JMS-1) - Modified

	A	B	C	D	E	F	G	H	I	J	K
1	**Project Mustang Valuation**										
2	Assumptions										
3	Weighted Average Cost of Capital	7.14%									
4	Tax Rate	39.40%		**Carbon adder removed from the market price of electiricity (revenues)**							
5	After Tax Terminal Value (Multiplier x EBITDA)	7.5									
6	Value for Depreciation Calcs	$ 896,000,000									
7	Kerr Conveyance Price	$ 25,000,000									
8											
9	Results										
10	Hydro Assets Net Present Value	$648,595,171		As Filed in JMS-1		Effect of Carbon Adder					
11	G&A and Contingencies Net Present Value	($70,095,083)									
12	**Total Value**	**$578,500,088**	-	**$825,879,110**	=	**$247,379,022**					
13											
14											
15											
16		**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
17											
18	Revenue	$ 104,804,565	$ 98,987,683	$ 80,842,567	$ 83,414,381	$ 88,636,526	$ 95,515,944	$ 103,985,505	$ 105,875,557	$ 108,090,412	$ 110,327,871
19	Generation Tax	$ (714,490)	$ (648,700)	$ (498,747)	$ (497,415)	$ (497,415)	$ (497,415)	$ (498,747)	$ (497,415)	$ (497,415)	$ (497,415)
20	Fixed Costs (Includes Kerr Rent)	$ (58,621,707)	$ (53,284,154)	$ (38,490,691)	$ (39,360,176)	$ (40,197,748)	$ (41,168,525)	$ (42,051,611)	$ (42,989,303)	$ (43,907,950)	$ (44,914,904)
21	EBITDA	$ 45,468,368	$ 45,054,829	$ 41,853,130	$ 43,556,789	$ 47,941,363	$ 53,850,004	$ 61,435,148	$ 62,388,840	$ 63,685,048	$ 64,915,552
22											
23	Tax Depreciation	$ (34,081,151)	$ (65,982,143)	$ (61,746,744)	$ (57,917,226)	$ (54,335,320)	$ (50,909,908)	$ (47,747,640)	$ (44,850,099)	$ (44,718,475)	$ (45,137,189)
24											
25	Income Taxes	$ (4,486,563)	$ 8,245,362	$ 7,838,084	$ 5,658,012	$ 2,519,219	$ (1,158,398)	$ (5,392,878)	$ (6,910,264)	$ (7,472,830)	$ (7,792,675)
26											
27	After Tax Cash Flow	$ 40,981,805	$ 53,300,191	$ 49,691,214	$ 49,214,802	$ 50,460,582	$ 52,691,606	$ 56,042,270	$ 55,478,576	$ 56,212,218	$ 57,122,877
28											
29	Capital Expenditures	$ (12,830,700)	$ (9,964,120)	$ (9,194,900)	$ (11,991,200)	$ (8,500,000)	$ (8,712,500)	$ (8,930,400)	$ (9,153,500)	$ (9,382,400)	$ (9,616,900)
30											
31	Terminal Value (Includes Kerr Conveyance)	$ -	$ 25,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32											
33	Asset Cash Flow	$ 28,151,105	$ 68,336,071	$ 40,496,314	$ 37,223,602	$ 41,960,582	$ 43,979,106	$ 47,111,870	$ 46,325,076	$ 46,829,818	$ 47,505,977
34											
35	After Tax G&A Expenses	$ (5,489,714)	$ (5,626,957)	$ (5,767,631)	$ (5,911,821)	$ (6,059,617)	$ (6,211,107)	$ (6,366,385)	$ (6,525,545)	$ (6,688,683)	$ (6,855,900)
36	After Tax Contingency Items	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (113,625)	$ (113,625)	$ (113,625)
37											
38	**Total Cash Flow**	**$ 22,661,391**	**$ 62,709,114**	**$ 34,728,683**	**$ 31,311,780**	**$ 35,900,965**	**$ 37,767,999**	**$ 40,745,485**	**$ 39,685,906**	**$ 40,027,510**	**$ 40,536,451**

Exhibit__(JMS-1) - Modified

	A	L	M	N	O	P	Q	R	S	T	U
1	**Project Mustang Valuation**										
2	Assumptions										
3	Weighted Average Cost of Capital										
4	Tax Rate										
5	After Tax Terminal Value (Multiplier x EBITDA)										
6	Value for Depreciation Calcs										
7	Kerr Conveyance Price										
8											
9	Results										
10	Hydro Assets Net Present Value										
11	G&A and Contingencies Net Present Value										
12	**Total Value**										
13											
14											
15											
16		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
17											
18	Revenue	$ 113,001,248	$ 115,067,130	$ 117,483,562	$ 119,948,268	$ 122,745,620	$ 124,988,484	$ 127,663,938	$ 130,346,786	$ 133,450,446	$ 136,232,345
19	Generation Tax	$ (498,747)	$ (497,415)	$ (497,415)	$ (497,415)	$ (498,747)	$ (497,415)	$ (497,415)	$ (497,415)	$ (498,747)	$ (498,747)
20	Fixed Costs (Includes Kerr Rent)	$ (45,882,445)	$ (46,894,644)	$ (47,879,884)	$ (48,958,851)	$ (50,018,100)	$ (51,075,976)	$ (52,175,898)	$ (53,321,587)	$ (54,477,571)	$ (52,529,079)
21	EBITDA	$ 66,620,056	$ 67,675,072	$ 69,106,263	$ 70,492,002	$ 72,228,774	$ 73,415,093	$ 74,990,625	$ 76,527,785	$ 78,474,128	$ 83,204,520
22											
23	Tax Depreciation	$ (45,591,585)	$ (46,051,320)	$ (46,542,727)	$ (47,028,165)	$ (47,543,609)	$ (48,054,393)	$ (48,596,127)	$ (49,132,455)	$ (49,700,480)	$ (50,264,493)
24											
25	Income Taxes	$ (8,285,217)	$ (8,519,758)	$ (8,890,033)	$ (9,244,752)	$ (9,725,955)	$ (9,992,116)	$ (10,399,432)	$ (10,793,760)	$ (11,336,817)	$ (12,978,370)
26											
27	After Tax Cash Flow	$ 58,334,839	$ 59,155,314	$ 60,216,230	$ 61,247,250	$ 62,502,819	$ 63,422,977	$ 64,591,193	$ 65,734,025	$ 67,137,311	$ 70,226,149
28											
29	Capital Expenditures	$ (9,874,500)	$ (10,103,800)	$ (10,365,400)	$ (10,615,300)	$ (10,880,700)	$ (11,170,600)	$ (11,431,700)	$ (11,717,400)	$ (12,010,200)	$ (12,310,455)
30											
31	Terminal Value (Includes Kerr Conveyance)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 624,033,898
32											
33	Asset Cash Flow	$ 48,460,339	$ 49,051,514	$ 49,850,830	$ 50,631,950	$ 51,622,119	$ 52,252,377	$ 53,159,493	$ 54,016,625	$ 55,127,111	$ 681,949,593
34											
35	After Tax G&A Expenses	$ (7,027,298)	$ (7,202,980)	$ (7,383,055)	$ (7,567,631)	$ (7,756,822)	$ (7,950,742)	$ (8,149,511)	$ (8,353,249)	$ (8,562,080)	$ (8,776,132)
36	After Tax Contingency Items	$ (113,625)	$ (340,875)	$ (113,625)	$ (113,625)	$ (113,625)	$ (113,625)	$ (113,625)	$ -	$ -	$ -
37											
38	**Total Cash Flow**	**$ 41,319,416**	**$ 41,507,659**	**$ 42,354,150**	**$ 42,950,694**	**$ 43,751,672**	**$ 44,188,010**	**$ 44,896,357**	**$ 45,663,376**	**$ 46,565,031**	**$ 673,173,461**

Exhibit JW-2

D2013.12.85

Exhibit__(JMS-1) - Modified

	A	B	C	D	E	F	G	H	I	J	K
1	**Project Mustang Valuation**										
2	Assumptions										
3	Weighted Average Cost of Capital	7.14%									
4	Tax Rate	39.40%		**Carbon Adder removed from the market price of electiricity (revenues) and**							
5	After Tax Terminal Value (Multiplier x EBITDA)	7.5		**Capital Expenditure increased to $17.8 Mlls in 2018.**							
6	Value for Depreciation Calcs	$ 896,000,000									
7	Kerr Conveyance Price	$ 25,000,000									
8											
9	Results										
10	Hydro Assets Net Present Value	$582,468,784		As Filed in JMS-1		Effect of Carbon Adder		Effect of Capex			
11	G&A and Contingencies Net Present Value	($70,095,083)									
12	**Total Value**	**$512,373,700**		**$825,879,110**		**$247,379,022**		**$66,126,388**			
13											
14											
15											
16		**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
17											
18	Revenue	$ 104,804,565	$ 98,987,683	$ 80,842,567	$ 83,414,381	$ 88,636,526	$ 95,515,944	$ 103,985,505	$ 105,875,557	$ 108,090,412	$ 110,327,871
19	Generation Tax	$ (714,490)	$ (648,700)	$ (498,747)	$ (497,415)	$ (497,415)	$ (497,415)	$ (498,747)	$ (497,415)	$ (497,415)	$ (497,415)
20	Fixed Costs (Includes Kerr Rent)	$ (58,621,707)	$ (53,284,154)	$ (38,490,691)	$ (39,360,176)	$ (40,197,748)	$ (41,168,525)	$ (42,051,611)	$ (42,989,303)	$ (43,907,950)	$ (44,914,904)
21	EBITDA	$ 45,468,368	$ 45,054,829	$ 41,853,130	$ 43,556,789	$ 47,941,363	$ 53,850,004	$ 61,435,148	$ 62,388,840	$ 63,685,048	$ 64,915,552
22											
23	Tax Depreciation	$ (34,081,151)	$ (65,982,143)	$ (61,746,744)	$ (57,917,226)	$ (54,684,070)	$ (51,938,744)	$ (49,423,154)	$ (47,141,962)	$ (47,598,947)	$ (48,581,181)
24											
25	Income Taxes	$ (4,486,563)	$ 8,245,362	$ 7,838,084	$ 5,658,012	$ 2,656,627	$ (753,037)	$ (4,732,725)	$ (6,007,270)	$ (6,337,924)	$ (6,435,742)
26											
27	After Tax Cash Flow	$ 40,981,805	$ 53,300,191	$ 49,691,214	$ 49,214,802	$ 50,597,989	$ 53,096,967	$ 56,702,422	$ 56,381,570	$ 57,347,124	$ 58,479,809
28											
29	Capital Expenditures	$ (12,830,700)	$ (9,964,120)	$ (9,194,900)	$ (11,991,200)	$ (17,800,000)	$ (18,245,000)	$ (18,701,125)	$ (19,168,653)	$ (19,647,869)	$ (20,139,066)
30											
31	Terminal Value (Includes Kerr Conveyance)	$ -	$ 25,000,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32											
33	Asset Cash Flow	$ 28,151,105	$ 68,336,071	$ 40,496,314	$ 37,223,602	$ 32,797,989	$ 34,851,967	$ 38,001,297	$ 37,212,917	$ 37,699,255	$ 38,340,743
34											
35	After Tax G&A Expenses	$ (5,489,714)	$ (5,626,957)	$ (5,767,631)	$ (5,911,821)	$ (6,059,617)	$ (6,211,107)	$ (6,366,385)	$ (6,525,545)	$ (6,688,683)	$ (6,855,900)
36	After Tax Contingency Items	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (113,625)	$ (113,625)	$ (113,625)
37											
38	**Total Cash Flow**	**$ 22,661,391**	**$ 62,709,114**	**$ 34,728,683**	**$ 31,311,780**	**$ 26,738,372**	**$ 28,640,860**	**$ 31,634,912**	**$ 30,573,747**	**$ 30,896,946**	**$ 31,371,218**

Exhibit__(JMS-1) - Modified

	A	L	M	N	O	P	Q	R	S	T	U
1	**Project Mustang Valuation**										
2	Assumptions										
3	Weighted Average Cost of Capital										
4	Tax Rate										
5	After Tax Terminal Value (Multiplier x EBITDA)										
6	Value for Depreciation Calcs										
7	Kerr Conveyance Price										
8											
9	Results										
10	Hydro Assets Net Present Value										
11	G&A and Contingencies Net Present Value										
12	**Total Value**										
13											
14											
15											
16		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
17											
18	Revenue	$ 113,001,248	$ 115,067,130	$ 117,483,562	$ 119,948,268	$ 122,745,620	$ 124,988,484	$ 127,663,938	$ 130,346,786	$ 133,450,446	$ 136,232,345
19	Generation Tax	$ (498,747)	$ (497,415)	$ (497,415)	$ (497,415)	$ (498,747)	$ (497,415)	$ (497,415)	$ (497,415)	$ (498,747)	$ (498,747)
20	Fixed Costs (Includes Kerr Rent)	$ (45,882,445)	$ (46,894,644)	$ (47,879,884)	$ (48,958,851)	$ (50,018,100)	$ (51,075,976)	$ (52,175,898)	$ (53,321,587)	$ (54,477,571)	$ (52,529,079)
21	EBITDA	$ 66,620,056	$ 67,675,072	$ 69,106,263	$ 70,492,002	$ 72,228,774	$ 73,415,093	$ 74,990,625	$ 76,527,785	$ 78,474,128	$ 83,204,520
22											
23	Tax Depreciation	$ (49,575,622)	$ (50,554,927)	$ (51,573,678)	$ (52,599,574)	$ (53,669,440)	$ (54,747,730)	$ (55,871,301)	$ (57,004,638)	$ (58,184,631)	$ (59,375,801)
24											
25	Income Taxes	$ (6,715,507)	$ (6,745,337)	$ (6,907,839)	$ (7,049,617)	$ (7,312,377)	$ (7,354,941)	$ (7,533,013)	$ (7,692,120)	$ (7,994,062)	$ (9,388,515)
26											
27	After Tax Cash Flow	$ 59,904,549	$ 60,929,735	$ 62,198,425	$ 63,442,385	$ 64,916,396	$ 66,060,152	$ 67,457,611	$ 68,835,665	$ 70,480,066	$ 73,816,005
28											
29	Capital Expenditures	$ (20,642,543)	$ (21,158,606)	$ (21,687,572)	$ (22,229,761)	$ (22,785,505)	$ (23,355,143)	$ (23,939,021)	$ (24,537,497)	$ (25,150,934)	$ (25,779,707)
30											
31	Terminal Value (Includes Kerr Conveyance)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 624,033,898
32											
33	Asset Cash Flow	$ 39,262,006	$ 39,771,128	$ 40,510,853	$ 41,212,624	$ 42,130,891	$ 42,705,010	$ 43,518,590	$ 44,298,168	$ 45,329,132	$ 672,070,196
34											
35	After Tax G&A Expenses	$ (7,027,298)	$ (7,202,980)	$ (7,383,055)	$ (7,567,631)	$ (7,756,822)	$ (7,950,742)	$ (8,149,511)	$ (8,353,249)	$ (8,562,080)	$ (8,776,132)
36	After Tax Contingency Items	$ (113,625)	$ (340,875)	$ (113,625)	$ (113,625)	$ (113,625)	$ (113,625)	$ (113,625)	$ -	$ -	$ -
37											
38	**Total Cash Flow**	**$ 32,121,083**	**$ 32,227,273**	**$ 33,014,173**	**$ 33,531,368**	**$ 34,260,444**	**$ 34,640,642**	**$ 35,255,454**	**$ 35,944,919**	**$ 36,767,052**	**$ 663,294,064**

Exhibit JW-3

D2013.12.85

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	**Exhibit__(TEM-2) - Modified**																
2	**Hydro Financials**			**Scenario 1. Delay Carbon for ten years and reduce increase to 2 1/2% per year.**													
3																	
4																	
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**															
19				**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
20	Rate Base (Beginning Balance)			**900,000**	**865,247**	**801,173**	**804,227**	**781,939**	**757,178**	**733,652**	**711,274**	**689,956**	**668,759**	**647,499**	**626,181**	**604,773**	**583,291**
21	Capex			12,831	(20,036)	9,195	11,991	8,500	8,713	8,930	9,154	9,382	9,617	9,875	10,104	10,365	10,615
22	Depreciation			(21,620)	(21,939)	(22,187)	(22,415)	(22,713)	(22,924)	(23,141)	(23,363)	(23,590)	(23,824)	(24,063)	(24,308)	(24,559)	(24,817)
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			(4,020)	(14,758)	(13,238)	(11,864)	(10,548)	(9,314)	(8,168)	(7,109)	(6,989)	(7,054)	(7,129)	(7,204)	(7,288)	(7,368)
25	Rate Base (Ending Balance)		**900,000**	**865,247**	**801,173**	**804,227**	**781,939**	**757,178**	**733,652**	**711,274**	**689,956**	**668,759**	**647,499**	**626,181**	**604,773**	**583,291**	**561,722**
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)			(6,415)	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Average Balance			**865,869**	**826,037**	**795,527**	**785,910**	**762,386**	**738,242**	**715,290**	**693,442**	**672,184**	**650,956**	**629,667**	**608,304**	**586,859**	**565,333**
29																	
30	MWs			633	571	439	439	439	439	439	439	439	439	439	439	439	439
31																	
32																	
33	Total MWh's	***NPV 5***	$551,069	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 10***	$947,172	$131,056	$128,686	$139,434	$139,158	$137,868	$137,242	$136,020	$137,352	$136,783	$137,110	$137,259	$137,564	$136,687	$135,961
35	Revenue Requirement ($'s per MWh)	***NPV 20***	$1,420,332	$64.93	$65.63	$59.82	$62.02	$62.26	$60.53	$59.51	$57.79	$57.20	$56.67	$56.20	$55.88	$55.40	$55.08
36	5 / 10 / 20 / 30 Year Level Price - Owned	***NPV 30***	$1,660,775	**$62.92**	**$60.97**	**$58.74**	**$58.15**										
37																	
38	Procure at Market ($000 Annual)	***NPV 5***	$293,312	$61,826	$65,044	$76,003	$77,657	$82,177	$89,495	$97,672	$101,724	$104,293	$107,588	$110,916	$113,933	$116,579	$119,099
39	Market Curve ($'s per MWh)	***NPV 10***	$581,385	$30.63	$33.17	$32.61	$34.61	$37.11	$39.47	$42.73	$42.80	$43.61	$44.47	$45.42	$46.28	$47.25	$48.25
40	5 / 10 / 20 / 30 Year Level Price - Market	***NPV 20***	$1,037,383	**$33.49**	**$37.42**	**$42.90**	**$48.26**										
41		***NPV 30***	$1,378,459														
42	***Income Statement***			**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
43	Revenue Requirement			$131,056	$128,686	$139,433	$139,158	$137,868	$137,242	$136,020	$137,352	$136,783	$137,111	$137,259	$137,564	$136,687	$135,961
44	Revenue Credit			40,628	31,985	4,582	5,378	6,027	5,659	5,959	3,953	3,620	2,612	1,986	1,084	865	811
45	Cost of Sales (EPLT & WET Taxes)			948	841	523	534	538	530	530	514	512	508	506	501	500	500
46	Gross Margin			$170,737	$159,830	$143,493	$144,002	$143,357	$142,371	$141,449	$140,791	$139,892	$139,215	$138,739	$138,147	$137,051	$136,272
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	682	739	738	731	727	721	728	725	727	727	729	724	721
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	57,289	43,059	43,984	45,137	46,172	47,164	48,317	49,359	50,457	51,552	52,922	53,792	54,981
57																	
58	EBITDA			108,368	102,541	100,434	100,019	98,220	96,199	94,285	92,474	90,533	88,758	87,187	85,225	83,258	81,291
59																	
60	Depreciation			21,620	21,939	22,187	22,415	22,713	22,924	23,141	23,363	23,590	23,824	24,063	24,308	24,559	24,817
61																	
62	Operating Income			86,748	80,602	78,247	77,604	75,507	73,274	71,144	69,111	66,943	64,935	63,124	60,917	58,699	56,475
63																	
64	Interest Expense			(20,261)	(19,329)	(18,615)	(18,390)	(17,840)	(17,275)	(16,738)	(16,227)	(15,729)	(15,232)	(14,734)	(14,234)	(13,732)	(13,229)
65	Non-Cash Interest Expense			-	-	-	-	-	-	-	-	-	-	-	-	-	-
66																	
67	Income before tax			66,487	61,273	59,632	59,213	57,667	56,000	54,406	52,884	51,214	49,702	48,390	46,683	44,967	43,246
68																	
69	Current Taxes			(21,663)	(7,526)	(8,590)	(9,972)	(10,844)	(11,575)	(12,238)	(12,830)	(12,307)	(11,638)	(11,037)	(10,280)	(9,509)	(8,742)
70	Deferred Taxes			(4,020)	(14,758)	(13,238)	(11,864)	(10,548)	(9,314)	(8,168)	(7,109)	(6,989)	(7,054)	(7,129)	(7,204)	(7,288)	(7,368)
71	Production Tax Credits			759	661	381	346	319	325	333	339	347	236	-	-	-	-
72	Income Tax Expense			(24,925)	(21,623)	(21,447)	(21,490)	(21,073)	(20,564)	(20,072)	(19,599)	(18,949)	(18,456)	(18,166)	(17,484)	(16,798)	(16,110)
73																	
74	**Net Income**			**$ 41,562**	**$ 39,650**	**$ 38,185**	**$ 37,724**	**$ 36,595**	**$ 35,436**	**$ 34,334**	**$ 33,285**	**$ 32,265**	**$ 31,246**	**$ 30,224**	**$ 29,199**	**$ 28,169**	**$ 27,136**
75	ETR			-37.4886%	-35.2896%	-35.9652%	-36.2919%	-36.5420%	-36.7217%	-36.8932%	-37.0604%	-36.9996%	-37.1338%	-37.5406%	-37.4530%	-37.3558%	-37.2517%
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-2) - Modified**																
2	**Hydro Financials**																
3																	
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)	**561,722**	**540,066**	**518,345**	**496,516**	**474,600**	**452,589**	**430,486**	**415,177**	**406,741**	**398,352**	**390,025**	**381,751**	**373,503**	**365,279**	**357,082**	**348,912**
21	Capex	10,881	11,171	11,432	11,717	12,010	12,310	12,618	12,934	13,257	13,588	13,928	14,276	14,633	14,999	15,374	15,758
22	Depreciation	(25,080)	(25,351)	(25,628)	(25,912)	(26,204)	(26,502)	(26,808)	(27,122)	(27,443)	(27,773)	(28,110)	(28,456)	(28,811)	(29,175)	(29,547)	(29,930)
23	Net Operating Loss Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Deferred Taxes	(7,456)	(7,540)	(7,633)	(7,721)	(7,818)	(7,911)	(1,119)	5,752	5,798	5,857	5,908	5,931	5,955	5,979	6,003	6,029
25	Rate Base (Ending Balance)	**540,066**	**518,345**	**496,516**	**474,600**	**452,589**	**430,486**	**415,177**	**406,741**	**398,352**	**390,025**	**381,751**	**373,503**	**365,279**	**357,082**	**348,912**	**340,769**
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	**543,721**	**522,032**	**500,257**	**478,385**	**456,421**	**434,364**	**415,658**	**403,786**	**395,373**	**387,016**	**378,715**	**370,454**	**362,218**	**354,007**	**345,824**	**337,667**
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)	$135,397	$134,583	$133,247	$132,629	$132,988	$131,075	$132,214	$134,114	$134,991	$135,917	$136,889	$137,902	$138,962	$140,069	$141,225	$142,431
35	Revenue Requirement ($'s per MWh)	$54.59	$54.41	$54.15	$53.68	$53.33	$52.56	$53.02	$53.78	$54.13	$54.50	$54.89	$55.30	$55.72	$56.17	$56.63	$57.12
36	5 / 10 / 20 / 30 Year Level Price - Owned																
37																	
38	Procure at Market ($000 Annual)	$122,118	$124,333	$126,372	$165,262	$170,429	$174,164	$177,971	$181,847	$185,822	$189,889	$194,054	$198,290	$202,622	$207,067	$211,609	$216,233
39	Market Curve ($'s per MWh)	$49.23	$50.27	$51.35	$66.89	$68.34	$69.84	$71.37	$72.92	$74.52	$76.15	$77.82	$79.52	$81.25	$83.04	$84.86	$86.71
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	$135,397	$134,583	$133,247	$132,629	$132,988	$131,075	$132,214	$134,114	$134,991	$135,917	$136,889	$137,902	$138,962	$140,069	$141,225	$142,431
44	Revenue Credit	600	626	1,235	1,030	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	$135,496	$134,710	$133,980	$133,159	$132,489	$130,576	$131,716	$133,615	$134,492	$135,418	$136,391	$137,404	$138,463	$139,570	$140,726	$141,932
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	718	713	706	703	705	695	701	711	715	720	726	731	736	742	748	755
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	56,176	57,362	58,608	59,765	61,077	61,148	62,496	63,879	65,288	66,730	68,205	69,715	71,260	72,841	74,459	76,114
57																	
58	EBITDA	79,320	77,347	75,372	73,394	71,412	69,428	69,220	69,736	69,204	68,688	68,185	67,688	67,203	66,729	66,268	65,818
59																	
60	Depreciation	25,080	25,351	25,628	25,912	26,204	26,502	26,808	27,122	27,443	27,773	28,110	28,456	28,811	29,175	29,547	29,930
61																	
62	Operating Income	54,239	51,997	49,744	47,481	45,208	42,926	42,412	42,615	41,761	40,916	40,075	39,232	38,392	37,555	36,720	35,889
63																	
64	Interest Expense	(12,723)	(12,216)	(11,706)	(11,194)	(10,680)	(10,164)	(9,726)	(9,449)	(9,252)	(9,056)	(8,862)	(8,669)	(8,476)	(8,284)	(8,092)	(7,901)
65	Non-Cash Interest Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66																	
67	Income before tax	41,516	39,781	38,038	36,287	34,528	32,762	32,685	33,166	32,509	31,860	31,213	30,563	29,916	29,271	28,628	27,987
68																	
69	Current Taxes	(7,961)	(7,183)	(6,393)	(5,604)	(4,802)	(4,002)	(11,615)	(19,536)	(19,329)	(19,140)	(18,943)	(18,713)	(18,484)	(18,257)	(18,032)	(17,808)
70	Deferred Taxes	(7,456)	(7,540)	(7,633)	(7,721)	(7,818)	(7,911)	(1,119)	5,752	5,798	5,857	5,908	5,931	5,955	5,979	6,003	6,029
71	Production Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Income Tax Expense	(15,417)	(14,724)	(14,025)	(13,325)	(12,620)	(11,912)	(12,734)	(13,784)	(13,531)	(13,283)	(13,035)	(12,782)	(12,530)	(12,279)	(12,028)	(11,779)
73																	
74	**Net Income**	**$ 26,099**	**$ 25,058**	**$ 24,012**	**$ 22,962**	**$ 21,908**	**$ 20,849**	**$ 19,952**	**$ 19,382**	**$ 18,978**	**$ 18,577**	**$ 18,178**	**$ 17,782**	**$ 17,386**	**$ 16,992**	**$ 16,600**	**$ 16,208**
75	ETR	-37.1361%	-37.0114%	-36.8721%	-36.7202%	-36.5491%	-36.3606%	-38.9584%	-41.5614%	-41.6231%	-41.6920%	-41.7603%	-41.8201%	-41.8827%	-41.9480%	-42.0162%	-42.0877%
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 JW-4

D2013.12.85

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	**Exhibit__(TEM-2) - Modified**																
2	**Hydro Financials**			**Scenario 2. Delay Carbon for ten years and reduce increase to 2 1/2% per year.**													
3				**plus $245 million (escalated at 2 1/2% per year from 2014) over 3 years 2024-2026 (1/3 each year).**													
4																	
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**															
19				**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
20	Rate Base (Beginning Balance)			**900,000**	**865,247**	**801,173**	**804,227**	**781,939**	**757,178**	**733,652**	**711,274**	**689,956**	**668,759**	**647,499**	**729,350**	**806,779**	**880,004**
21	Capex			12,831	(20,036)	9,195	11,991	8,500	8,713	8,930	9,154	9,382	9,617	114,415	114,644	114,906	10,615
22	Depreciation			(21,620)	(21,939)	(22,187)	(22,415)	(22,713)	(22,924)	(23,141)	(23,363)	(23,590)	(23,824)	(24,063)	(26,906)	(29,755)	(32,610)
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			(4,020)	(14,758)	(13,238)	(11,864)	(10,548)	(9,314)	(8,168)	(7,109)	(6,989)	(7,054)	(8,501)	(10,308)	(11,926)	(11,985)
25	Rate Base (Ending Balance)		**900,000**	**865,247**	**801,173**	**804,227**	**781,939**	**757,178**	**733,652**	**711,274**	**689,956**	**668,759**	**647,499**	**729,350**	**806,779**	**880,004**	**846,024**
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)			(6,415)	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Average Balance			**865,869**	**826,037**	**795,527**	**785,910**	**762,386**	**738,242**	**715,290**	**693,442**	**672,184**	**650,956**	**681,251**	**760,891**	**836,218**	**855,841**
29																	
30	MWs			633	571	439	439	439	439	439	439	439	439	439	439	439	439
31																	
32																	
33	Total MWh's	***NPV 5***	$551,069	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 10***	$947,172	$131,056	$128,686	$139,433	$139,158	$137,868	$137,242	$136,020	$137,352	$136,783	$137,110	$142,294	$155,268	$166,664	$172,799
35	Revenue Requirement ($'s per MWh)	***NPV 20***	$1,516,854	$64.93	$65.63	$59.82	$62.02	$62.26	$60.53	$59.51	$57.79	$57.20	$56.67	$58.27	$63.08	$67.55	$70.01
36	5 / 10 / 20 / 30 Year Level Price - Owned	***NPV 30***	$1,802,060	**$62.92**	**$60.97**	**$62.73**	**$63.09**										
37																	
38	Procure at Market ($000 Annual)	***NPV 5***	$293,312	$61,826	$65,044	$76,003	$77,657	$82,177	$89,495	$97,672	$101,724	$104,293	$107,588	$110,916	$113,933	$116,579	$119,099
39	Market Curve ($'s per MWh)	***NPV 10***	$581,385	$30.63	$33.17	$32.61	$34.61	$37.11	$39.47	$42.73	$42.80	$43.61	$44.47	$45.42	$46.28	$47.25	$48.25
40	5 / 10 / 20 / 30 Year Level Price - Market	***NPV 20***	$1,037,383	**$33.49**	**$37.42**	**$42.90**	**$48.26**										
41		***NPV 30***	$1,378,459														
42	***Income Statement***			**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
43	Revenue Requirement			$131,056	$128,686	$139,434	$139,158	$137,868	$137,242	$136,020	$137,352	$136,783	$137,111	$142,294	$155,268	$166,664	$172,799
44	Revenue Credit			40,628	31,985	4,582	5,378	6,027	5,659	5,959	3,953	3,620	2,612	1,986	1,084	865	811
45	Cost of Sales (EPLT & WET Taxes)			948	841	523	534	538	530	530	514	512	508	506	501	500	500
46	Gross Margin			$170,737	$159,830	$143,493	$144,002	$143,357	$142,371	$141,449	$140,791	$139,892	$139,215	$143,774	$155,851	$167,029	$173,110
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	682	739	738	731	727	721	728	725	727	754	823	883	916
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	57,289	43,059	43,984	45,137	46,172	47,164	48,317	49,359	50,457	51,579	53,016	53,951	55,176
57																	
58	EBITDA			108,368	102,541	100,434	100,019	98,220	96,199	94,285	92,474	90,533	88,758	92,195	102,835	113,077	117,934
59																	
60	Depreciation			21,620	21,939	22,187	22,415	22,713	22,924	23,141	23,363	23,590	23,824	24,063	26,906	29,755	32,610
61																	
62	Operating Income			86,748	80,602	78,247	77,604	75,507	73,274	71,144	69,111	66,943	64,935	68,132	75,929	83,322	85,323
63																	
64	Interest Expense			(20,261)	(19,329)	(18,615)	(18,390)	(17,840)	(17,275)	(16,738)	(16,227)	(15,729)	(15,232)	(15,941)	(17,805)	(19,568)	(20,027)
65	Non-Cash Interest Expense			-	-	-	-	-	-	-	-	-	-	-	-	-	-
66																	
67	Income before tax			66,487	61,273	59,632	59,213	57,667	56,000	54,406	52,884	51,214	49,702	52,191	58,124	63,755	65,297
68																	
69	Current Taxes			(21,663)	(7,526)	(8,590)	(9,972)	(10,844)	(11,575)	(12,238)	(12,830)	(12,307)	(11,638)	(10,990)	(11,293)	(11,690)	(12,232)
70	Deferred Taxes			(4,020)	(14,758)	(13,238)	(11,864)	(10,548)	(9,314)	(8,168)	(7,109)	(6,989)	(7,054)	(8,501)	(10,308)	(11,926)	(11,985)
71	Production Tax Credits			759	661	381	346	319	325	333	339	347	236	-	-	-	-
72	Income Tax Expense			(24,925)	(21,623)	(21,447)	(21,490)	(21,073)	(20,564)	(20,072)	(19,599)	(18,949)	(18,456)	(19,491)	(21,601)	(23,616)	(24,216)
73																	
74	**Net Income**			**$ 41,562**	**$ 39,650**	**$ 38,185**	**$ 37,724**	**$ 36,594**	**$ 35,436**	**$ 34,334**	**$ 33,285**	**$ 32,265**	**$ 31,246**	**$ 32,700**	**$ 36,523**	**$ 40,138**	**$ 41,080**
75	ETR			-37.4886%	-35.2896%	-35.9652%	-36.2919%	-36.5420%	-36.7217%	-36.8932%	-37.0604%	-36.9996%	-37.1338%	-37.3456%	-37.1643%	-37.0425%	-37.0866%
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-2) - Modified**																
2	**Hydro Financials**																
3																	
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)	**846,024**	**812,509**	**779,438**	**746,730**	**714,371**	**682,219**	**650,131**	**624,859**	**606,459**	**588,107**	**569,817**	**551,580**	**533,368**	**515,181**	**497,021**	**478,887**
21	Capex	10,881	11,171	11,432	11,717	12,010	12,310	12,618	12,934	13,257	13,588	13,928	14,276	14,633	14,999	15,374	15,758
22	Depreciation	(32,874)	(33,145)	(33,422)	(33,706)	(33,997)	(34,296)	(34,602)	(34,915)	(35,237)	(35,566)	(35,904)	(36,250)	(36,605)	(36,969)	(37,341)	(37,723)
23	Net Operating Loss Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Deferred Taxes	(11,522)	(11,097)	(10,717)	(10,370)	(10,166)	(10,102)	(3,288)	3,582	3,628	3,688	3,739	3,762	3,785	3,809	3,834	3,859
25	Rate Base (Ending Balance)	**812,509**	**779,438**	**746,730**	**714,371**	**682,219**	**650,131**	**624,859**	**606,459**	**588,107**	**569,817**	**551,580**	**533,368**	**515,181**	**497,021**	**478,887**	**460,782**
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	**822,093**	**788,800**	**755,911**	**723,378**	**691,122**	**659,001**	**630,321**	**608,486**	**590,110**	**571,789**	**553,525**	**535,301**	**517,101**	**498,928**	**480,781**	**462,661**
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)	$171,098	$169,193	$166,809	$165,182	$164,541	$161,623	$161,739	$162,610	$162,460	$162,359	$162,303	$162,289	$162,321	$162,400	$162,528	$162,707
35	Revenue Requirement ($'s per MWh)	$68.98	$68.40	$67.78	$66.86	$65.98	$64.81	$64.86	$65.21	$65.15	$65.11	$65.08	$65.08	$65.09	$65.12	$65.17	$65.25
36	5 / 10 / 20 / 30 Year Level Price - Owned																
37																	
38	Procure at Market ($000 Annual)	$122,118	$124,333	$126,372	$165,262	$170,429	$174,164	$177,971	$181,847	$185,822	$189,889	$194,054	$198,290	$202,622	$207,067	$211,609	$216,233
39	Market Curve ($'s per MWh)	$49.23	$50.27	$51.35	$66.89	$68.34	$69.84	$71.37	$72.92	$74.52	$76.15	$77.82	$79.52	$81.25	$83.04	$84.86	$86.71
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	$171,098	$169,193	$166,809	$165,182	$164,541	$161,623	$161,739	$162,610	$162,460	$162,359	$162,303	$162,289	$162,321	$162,400	$162,528	$162,707
44	Revenue Credit	600	626	1,235	1,030	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	$171,197	$169,319	$167,542	$165,711	$164,043	$161,124	$161,240	$162,112	$161,961	$161,860	$161,804	$161,790	$161,822	$161,901	$162,030	$162,208
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	907	897	884	875	872	857	857	862	861	861	860	860	860	861	861	862
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	56,366	57,546	58,786	59,937	61,244	61,310	62,652	64,030	65,434	66,870	68,340	69,844	71,384	72,959	74,572	76,221
57																	
58	EBITDA	114,831	111,774	108,756	105,774	102,798	99,815	98,587	98,082	96,527	94,990	93,464	91,945	90,438	88,942	87,458	85,987
59																	
60	Depreciation	32,874	33,145	33,422	33,706	33,997	34,296	34,602	34,915	35,237	35,566	35,904	36,250	36,605	36,969	37,341	37,723
61																	
62	Operating Income	81,957	78,629	75,334	72,068	68,801	65,519	63,986	63,166	61,291	59,423	57,560	55,695	53,833	51,974	50,117	48,263
63																	
64	Interest Expense	(19,237)	(18,458)	(17,688)	(16,927)	(16,172)	(15,421)	(14,750)	(14,239)	(13,809)	(13,380)	(12,952)	(12,526)	(12,100)	(11,675)	(11,250)	(10,826)
65	Non-Cash Interest Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66																	
67	Income before tax	62,720	60,171	57,645	55,141	52,629	50,098	49,236	48,928	47,482	46,044	44,608	43,169	41,733	40,299	38,867	37,437
68																	
69	Current Taxes	(11,738)	(11,212)	(10,644)	(10,049)	(9,289)	(8,363)	(15,692)	(23,303)	(22,785)	(22,285)	(21,777)	(21,237)	(20,697)	(20,159)	(19,623)	(19,089)
70	Deferred Taxes	(11,522)	(11,097)	(10,717)	(10,370)	(10,166)	(10,102)	(3,288)	3,582	3,628	3,688	3,739	3,762	3,785	3,809	3,834	3,859
71	Production Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Income Tax Expense	(23,259)	(22,309)	(21,362)	(20,419)	(19,455)	(18,466)	(18,981)	(19,721)	(19,157)	(18,598)	(18,039)	(17,475)	(16,912)	(16,350)	(15,789)	(15,229)
73																	
74	**Net Income**	**$ 39,460**	**$ 37,862**	**$ 36,284**	**$ 34,722**	**$ 33,174**	**$ 31,632**	**$ 30,255**	**$ 29,207**	**$ 28,325**	**$ 27,446**	**$ 26,569**	**$ 25,694**	**$ 24,821**	**$ 23,949**	**$ 23,077**	**$ 22,208**
75	ETR	-37.0847%	-37.0757%	-37.0569%	-37.0300%	-36.9661%	-36.8596%	-38.5502%	-40.3053%	-40.3453%	-40.3915%	-40.4381%	-40.4799%	-40.5244%	-40.5725%	-40.6240%	-40.6798%
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 JW-5

D2013.12.85

DCF MODEL - COMBINATION GROUP

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)	(a)
		Earnings Growth				br+sv
	Company	V Line	IBES	Zacks	Reuters	Growth
1	ALLETE	10.9%	9.9%	9.9%	9.9%	9.2%
2	Ameren Corp.	3.9%	6.5%	7.1%	6.5%	7.3%
3	American Elec Pwr	8.8%	8.7%	8.3%	8.3%	8.5%
4	Avista Corp.	8.6%	9.1%	9.6%	9.6%	7.5%
5	Black Hills Corp.	14.5%	7.0%	7.0%	7.0%	7.1%
6	CMS Energy Corp.	9.4%	10.0%	10.0%	10.0%	8.9%
7	DTE Energy Co.	7.9%	8.7%	9.2%	8.7%	7.6%
8	Duke Energy Corp.	8.4%	8.1%	8.1%	8.3%	7.0%
9	Edison International	4.4%	3.6%	3.5%	4.3%	8.8%
10	El Paso Electric	6.1%	6.8%	2.1%	NA	8.7%
11	Empire District Elec	9.5%	7.5%	7.5%	NA	7.4%
12	Great Plains Energy	10.5%	10.4%	10.5%	10.4%	7.2%
13	Hawaiian Elec.	8.2%	7.1%	7.1%	8.4%	7.9%
14	IDACORP, Inc.	5.4%	7.4%	7.4%	NA	7.5%
15	NorthWestern Corp.	7.9%	10.4%	8.4%	10.4%	6.5%
16	Otter Tail Corp.	25.5%	10.0%	NA	NA	9.4%
17	PG&E Corp.	6.9%	6.9%	8.0%	6.1%	7.5%
18	Portland General Elec.	7.3%	10.2%	9.2%	10.0%	7.8%
19	PPL Corp.	4.9%	9.9%	2.0%	5.3%	10.0%
20	SCANA Corp.	8.9%	9.0%	9.1%	9.2%	9.9%
21	Sempra Energy	7.4%	5.8%	7.8%	8.3%	8.1%
22	UIL Holdings	8.5%	11.7%	11.9%	11.2%	7.5%
23	UNS Energy	10.1%	11.6%	10.5%	NA	8.7%
24	Westar Energy	10.4%	6.2%	7.9%	6.2%	8.7%
	Average (b)	**9.5%**	**9.7%**	**9.1%**	**9.4%**	**8.5%**
	Midpoint (c)	**11.2%**	**9.6%**	**9.7%**	**9.7%**	**8.8%**

(a) Sum of dividend yield (Exhibit NWE-4, p. 1) and respective growth rate (Exhibit NWE-4, p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

DCF MODEL - COMBINATION GROUP

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)	(a)
		Earnings Growth				br+sv
	Company	V Line	IBES	Zacks	Reuters	Growth
1	ALLETE	10.9%	9.9%	9.9%	9.9%	9.2%
2	Ameren Corp.	3.9%	6.5%	7.1%	6.5%	7.3%
3	American Elec Pwr	8.8%	8.7%	8.3%	8.3%	8.5%
4	Avista Corp.	8.6%	9.1%	9.6%	9.6%	7.5%
5	Black Hills Corp.	14.5%	7.0%	7.0%	7.0%	7.1%
6	CMS Energy Corp.	9.4%	10.0%	10.0%	10.0%	8.9%
7	DTE Energy Co.	7.9%	8.7%	9.2%	8.7%	7.6%
8	Duke Energy Corp.	8.4%	8.1%	8.1%	8.3%	7.0%
9	Edison International	4.4%	3.6%	3.5%	4.3%	8.8%
10	El Paso Electric	6.1%	6.8%	2.1%	NA	8.7%
11	Empire District Elec	9.5%	7.5%	7.5%	NA	7.4%
12	Great Plains Energy	10.5%	10.4%	10.5%	10.4%	7.2%
13	Hawaiian Elec.	8.2%	7.1%	7.1%	8.4%	7.9%
14	IDACORP, Inc.	5.4%	7.4%	7.4%	NA	7.5%
15	NorthWestern Corp.	7.9%	10.4%	8.4%	10.4%	6.5%
16	Otter Tail Corp.	25.5%	10.0%	NA	NA	9.4%
17	PG&E Corp.	6.9%	6.9%	8.0%	6.1%	7.5%
18	Portland General Elec.	7.3%	10.2%	9.2%	10.0%	7.8%
19	PPL Corp.	4.9%	9.9%	2.0%	5.3%	10.0%
20	SCANA Corp.	8.9%	9.0%	9.1%	9.2%	9.9%
21	Sempra Energy	7.4%	5.8%	7.8%	8.3%	8.1%
22	UIL Holdings	8.5%	11.7%	11.9%	11.2%	7.5%
23	UNS Energy	10.1%	11.6%	10.5%	NA	8.7%
24	Westar Energy	10.4%	6.2%	7.9%	6.2%	8.7%
	Average (b)	**8.9%**	**8.4%**	**7.9%**	**8.3%**	**8.1%**
	Median (b)	**8.5%**	**8.7%**	**8.1%**	**8.4%**	**7.8%**
	Midpoint (c)	**14.7%**	**7.6%**	**6.9%**	**7.7%**	**8.3%**

(a) Sum of dividend yield (, p. 1) and respective growth rate (, p. 2).
(b) Include all figures.
(c) Average of low and high values.

DCF MODEL - COMBINATION GROUP

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)	(a)
		Earnings Growth				**br+sv**
	Company	**V Line**	**IBES**	**Zacks**	**Reuters**	**Growth**
1	ALLETE	10.9%	9.9%	9.9%	9.9%	9.2%
2	Ameren Corp.	3.9%	6.5%	7.1%	6.5%	7.3%
3	American Elec Pwr	8.8%	8.7%	8.3%	8.3%	8.5%
4	Avista Corp.	8.6%	9.1%	9.6%	9.6%	7.5%
5	Black Hills Corp.	14.5%	7.0%	7.0%	7.0%	7.1%
6	CMS Energy Corp.	9.4%	10.0%	10.0%	10.0%	8.9%
7	DTE Energy Co.	7.9%	8.7%	9.2%	8.7%	7.6%
8	Duke Energy Corp.	8.4%	8.1%	8.1%	8.3%	7.0%
9	Edison International	4.4%	3.6%	3.5%	4.3%	8.8%
10	El Paso Electric	6.1%	6.8%	2.1%	NA	8.7%
11	Empire District Elec	9.5%	7.5%	7.5%	NA	7.4%
12	Great Plains Energy	10.5%	10.4%	10.5%	10.4%	7.2%
13	Hawaiian Elec.	8.2%	7.1%	7.1%	8.4%	7.9%
14	IDACORP, Inc.	5.4%	7.4%	7.4%	NA	7.5%
15	NorthWestern Corp.	7.9%	10.4%	8.4%	10.4%	6.5%
16	Otter Tail Corp.	25.5%	10.0%	NA	NA	9.4%
17	PG&E Corp.	6.9%	6.9%	8.0%	6.1%	7.5%
18	Portland General Elec.	7.3%	10.2%	9.2%	10.0%	7.8%
19	PPL Corp.	4.9%	9.9%	2.0%	5.3%	10.0%
20	SCANA Corp.	8.9%	9.0%	9.1%	9.2%	9.9%
21	Sempra Energy	7.4%	5.8%	7.8%	8.3%	8.1%
22	UIL Holdings	8.5%	11.7%	11.9%	11.2%	7.5%
23	UNS Energy	10.1%	11.6%	10.5%	NA	8.7%
24	Westar Energy	10.4%	6.2%	7.9%	6.2%	8.7%
	Average (b)	**8.6%**	**8.8%**	**8.7%**	**8.7%**	**8.1%**
	Median (b)	**8.6%**	**8.9%**	**8.4%**	**8.7%**	**7.8%**
	Midpoint (c)	**8.5%**	**9.0%**	**9.5%**	**8.6%**	**8.3%**

(a) Sum of dividend yield (, p. 1) and respective growth rate (, p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

Exhibit JW-6

D2013.12.85

Comparable Expected Market Earnings Rates

<u>COMBINATION GROUP</u>

	Company	Projected Book Return	Projected Market/Book	Expected Market Earnings Rate
1	ALLETE	10.3%	1.34	7.69%
2	Ameren Corp.	8.5%	1.14	7.41%
3	American Elec Pwr	9.9%	1.33	7.41%
4	Avista Corp.	8.3%	1.21	6.90%
5	Black Hills Corp.	9.0%	1.13	8.00%
6	CMS Energy Corp.	12.3%	1.66	7.41%
7	DTE Energy Co.	9.0%	1.30	6.90%
8	Duke Energy Corp.	7.7%	1.00	7.69%
9	Edison International	10.5%	1.37	7.69%
10	El Paso Electric	10.4%	1.40	7.41%
11	Empire District Elec	8.7%	1.13	7.69%
12	Great Plains Energy	8.0%	0.96	8.33%
13	Hawaiian Elec.	8.3%	1.21	6.90%
14	IDACORP, Inc.	8.4%	1.09	7.69%
15	NorthWestern Corp.	7.7%	0.96	8.00%
16	Otter Tail Corp.	11.1%	1.67	6.67%
17	PG&E Corp.	8.4%	1.26	6.67%
18	Portland General Elec.	8.5%	1.06	8.00%
19	PPL Corp.	10.8%	1.45	7.41%
20	SCANA Corp.	9.8%	1.22	8.00%
21	Sempra Energy	10.5%	1.53	6.90%
22	UIL Holdings	9.0%	1.43	6.25%
23	UNS Energy	11.6%	1.63	7.14%
24	Westar Energy	9.1%	1.14	8.0%
	Average	**9.4%**	**1.28**	**7.4%**
	Median	**9.0%**	**1.24**	**7.4%**

Source:
The Value Line Investment Survey (Sep. 20, Nov. 1, & Nov. 22, 2013).