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May 19, 2010

VIA ELECTRONIC FILING

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: Docket LC 50

Enclosed for filing in the above referenced docket are an original and one copy of Idaho Power Company's Response to Intervenor and Public Comments in its 2009 Integrated Resource Plan.

A copy of this filing has been served on all parties to this proceeding as indicated on the attached Certificate of Service.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Legal Assistant

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing documents on in Docket LC 50 on the following named persons on the date indicated below by e-mail addressed to said persons at his or her last-known address indicated below.

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DATED: May 19, 2010

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BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

LC 50

In the Matter of Idaho Power Company's 2009 Integrated Resource Plan	**IDAHO POWER COMPANY'S RESPONSE TO INTERVENOR AND PUBLIC COMMENTS IN ITS 2009 INTEGRATED RESOURCE PLAN**

Pursuant to the Administrative Law Judge's Memorandum dated March 5, 2010, Idaho Power Company ("Idaho Power" or "Company") hereby files its response to the intervenor and public comments on its 2009 Integrated Resource Plan ("IRP" or "2009 IRP"). Specifically, the following comments respond to the written and oral comments provided by intervenors and members of the public at the Public Hearing conducted by the Public Utility Commission of Oregon ("Commission") in Ontario, Oregon on April 20, 2010, and the written comments filed by Renewable Northwest Project ("RNP") on that same day.

I. INTRODUCTION

Aside from the limited concerns voiced by RNP, all of the comments received by the Commission regarding the Company's 2009 IRP came from members of the public who attended the April 20, 2010, Ontario Public Hearing. The majority of these persons identified themselves as members of intervenor Stop Idaho Power ("SIP") or Move Idaho Power ("MIP")—two organizations dedicated to halting or rerouting the Boardman to Hemingway Transmission Project ("B2H") included in the 2009 IRP preferred portfolio. Others commenters identified as private citizens.[1] The primary concern voiced by all of these commenters the need for and impact of B2H. Specifically, these commenters

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[1] In addition, one commenter at the Public Hearing identified himself as a member of an historic preservation organization.

suggest that the Company overstates future loads, understates future committed resources, and could better satisfy future deficiencies with resources other than B2H. In addition, the commenters argue that Idaho Power's plans to build B2H are motivated by a desire for shareholder profits, and that in fact B2H will not benefit Oregon residents. While Idaho Power appreciates the participation of all commenters, analysis shows that their concerns are not well founded.

- *First*, the load forecast used in Idaho Power's IRP is sound. It is based on careful research and up-to-date data and is actually conservative when compared with the load forecast produced by the Northwest Power and Conservation Council ("NPCC").
- *Second*, the existing and committed resources within the IRP are correctly represented.
- *Third,* none of the alternative approaches to serving the Company's projected load suggested by the intervenors and members of the public are viable or cost effective substitutes for B2H.
- *Fourth,* the Company's need to build out its system in order to accommodate wheeling requests is legitimate. There is no basis in fact for the commenters' accusations that the Company is motivated to build B2H by a desire to generate wheeling revenues that will result in shareholder profits.
- *Finally,* the Commission should reject the commenters' suggestions that B2H will not benefit Oregonians and that regional concerns are not relevant to the need for B2H. In fact, B2H will benefit Oregonians both directly, by supporting increased load in Idaho Power's Oregon service area, and indirectly by adding strength and flexibility to the regional transmission system.

II. DISCUSSION

A. Idaho Power's Load Forecast is Sound

1. General Background on Load Forecast—Structure and Methodology.

Idaho Power's IRP represents the Company's primary planning process for carrying out its mission of delivering safe, reliable, and cost effective electricity to its customers. Four primary goals are central to its preparation:

1. Identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20 year planning period.
2. Ensure the selected resource portfolio balances cost, risk, and environmental concerns.
3. Give equal and balanced treatment to both supply-side resources and demand-side measures.
4. Involve the public in the planning process in a meaningful way. In fulfillment of this last goal the Company works closely with the IRP Advisory Council (IRPAC), comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, public utility commission representatives, and others. The IRPAC generally meets monthly during the development of the IRP and the meetings are open to the public.

Clearly, a reliable load forecast is central to accomplishing the first of these goals. Without an accurate estimate of future demand, the Company cannot determine the resources it will need. Accordingly Idaho Power applies a rigorous process for developing the load forecasts used in the IRP.

In constructing the load forecast Idaho Power develops independent forecasts for each of the major customer classes: residential, commercial, irrigation, and industrial. Individual forecasts are also developed for Idaho Power's special contract customers (greater than 25 MW) that are then combined into a single forecast category labeled "Additional Firm Load."

The peak-hour load forecast is prepared in conjunction with the average load forecast. Idaho Power has two distinct peak periods: a winter peak, resulting from space heating demand that normally occurs in December, January, or February, and a larger summer peak that normally occurs in June or July. The summer peak generally occurs when extensive air conditioning usage coincides with significant irrigation demand.

Peak loads are forecast using 12 regression equations and are a function of temperature, space heating saturation (winter only), air conditioning saturation (summer only), historical average load, and precipitation (summer only). The peak forecast uses statistically derived peak day temperatures based on the most recent 30 years of climate data for each month. Peak loads for special contract customers are forecast based on historical analysis and contractual considerations.

The primary exogenous factors in the forecast are macroeconomic and demographic data. Moody's Analytics independently develops and provides the macroeconomic drivers used to prepare the load forecast. National, state, and county economic and demographic projections are tailored to Idaho Power's service area using an in-house economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data.

The initial load forecast for the 2009 IRP was completed in August 2008 and Idaho Power continued to perform the analytical work required to complete the IRP through the fall and winter of 2008. As work on the IRP continued, the national recession continued to worsen. By the spring of 2009, IRPAC members expressed concerns that the IRP load forecast did not account for the effects of the recession. In response to those concerns, Idaho Power filed a request for an extension of the IRP submittal date with the Commission to allow the Company time to update the load forecast and account for the recession. This request was granted by the Commission and the revised filing date for the IRP was extended to the end of December 2009.[2] The extension allowed the Company to include the most current economic data and thereby account for the effects of the recent recession.

2. Comparison with the NPCC Data Shows that the IRP Load Forecast is Conservative.

Several people argued at the Public Hearing that the load forecast contained in the NPCC's Sixth Power Plan demonstrates that Idaho Power's load forecast is unrealistically aggressive.[3] However, a careful analysis of the NPCC data shows that the IRP load forecast is actually conservative.

At the outset, it must be noted that the NPCC's forecast for the state of Idaho includes the entire state while Idaho Power's IRP load forecast covers only Idaho Power's service area—of which approximately 95 percent is in Idaho and 5 percent is in Eastern Oregon. Therefore, the load volumes are not directly comparable. However, the general *trends* of each forecast *can* be compared and contrasted, and these trends show the conservative nature of the IRP forecast. Figure 1, shown below, illustrates the 20-year expected case average load forecast for the state of Idaho prepared by the NPCC and the expected case average load forecast used in the 2009 IRP (for loads in the Company's service area).

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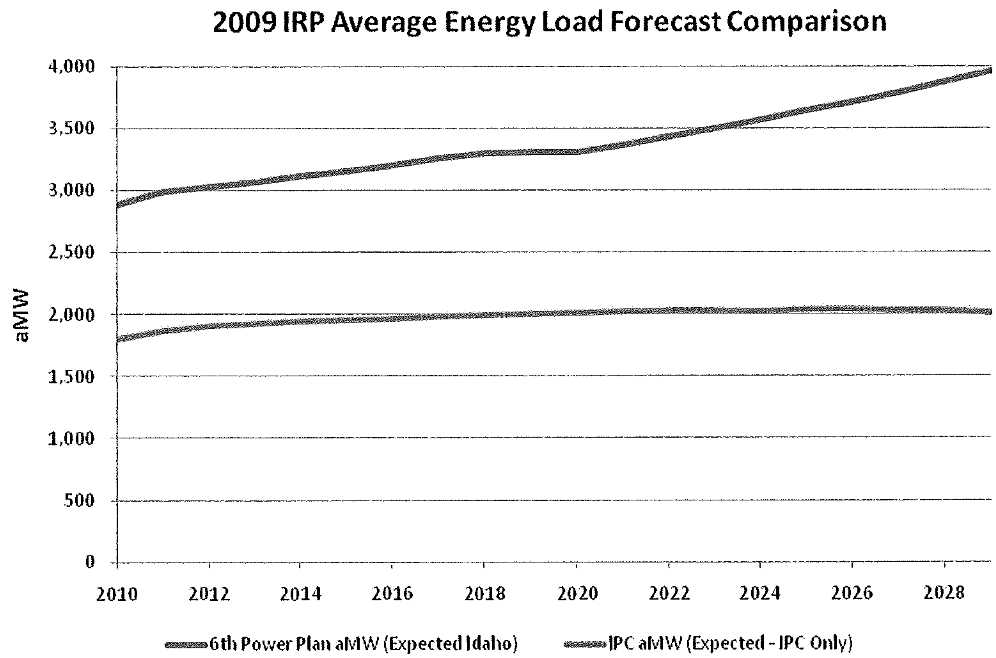
[2] *Re Idaho Power Compnay*, Docket UM 1428, Order No. 09-183 (May 26, 2010) (granting Idaho Power's request for extension of time to file 2009 IRP).

[3] Tr. 21:18 – 25:7 (Kennington); Tr. 58:23 – 60:5 (Williams).

Figure 1



Idaho Power's IRP forecast is lower than the NPCC forecast because the IRP forecast includes load only in Idaho Power's service area. From 2010 through 2020, the load forecast used in the 2009 IRP increases at a slightly lower rate than the growth shown in the NPCC forecast. From 2020 through 2029, the IRP load forecast shows little growth in average loads, due primarily to assumptions regarding the price elasticity impact of carbon regulation.

A comparison of the peak-hour forecasts yields similar results. As shown in Figure 2 below, the NPCC's forecast growth trend for peak-hour load from 2010 through 2020 is almost identical to Idaho Power's IRP forecast. From 2020 through 2029, Idaho Power's peak-hour forecast grows significantly less than the NPCC forecast, again due primarily to carbon regulation assumptions.

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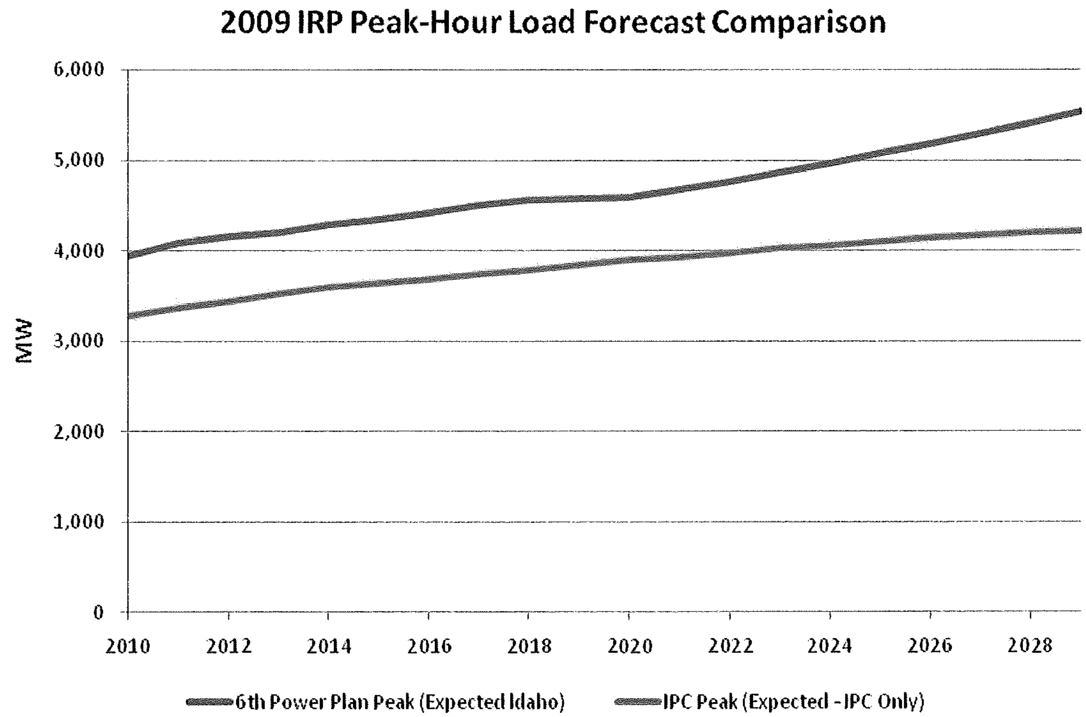
Figure 2



When comparing the 20-year periods in each forecast, the NPCC average load forecast grows at an annual average rate of 1.96 percent and Idaho Power's forecast grows at 0.64 percent. For peak-hour, the NPCC forecast grows at an annual average rate of 2.13 percent and Idaho Power's forecast grows at 1.5 percent. In both cases, Idaho Power's forecast growth rate is conservative when compared to the NPCC forecast. The data used to prepare Figures 1 and 2 is presented in Table 1.

Table 1 - Load Forecast Comparison Data

Year	NPCC Peak (State of Idaho)	IPC Peak (IPC Only)	NPCC aMW (State of Idaho)	IPC aMW (IPC Only)
2010	3,940	3,279	2,880	1,797
2011	4,092	3,375	2,988	1,869
2012	4,155	3,447	3,029	1,906
2013	4,208	3,533	3,062	1,926
2014	4,286	3,592	3,113	1,947
2015	4,348	3,641	3,153	1,957
2016	4,415	3,689	3,197	1,967
2017	4,500	3,739	3,254	1,979
2018	4,561	3,790	3,294	1,991
2019	4,582	3,842	3,304	2,002
2020	4,595	3,895	3,309	2,013
2021	4,673	3,933	3,361	2,017
2022	4,770	3,980	3,428	2,026
2023	4,871	4,027	3,497	2,032
2024	4,971	4,052	3,566	2,024
2025	5,080	4,098	3,640	2,035
2026	5,184	4,146	3,711	2,041
2027	5,295	4,173	3,788	2,034
2028	5,411	4,204	3,868	2,030
2029	5,535	4,216	3,953	2,015
		Average Annual Growth Rate		
	2.13%	**1.50%**	**1.96%**	**0.64%**

3. Specific Criticisms of the Load Forecast Methodologies and Calculations are Without Merit.

At the Public Hearing, two commenters, Mr. Roger Findley and Ms. Evelyn Sayers, provided specific analyses of the IRP load forecast calculation, all suggesting that the load forecast is aggressive. The Company has reviewed these criticisms and finds them to be based on a misunderstanding of the Company's methodology.

Mr. Findley begins his critique at the Public Hearing by pointing out that Table 3.1 and Figure 3.1 in the 2009 IRP contain data only through 2008. Mr. Findley suggests that this represents an attempt on Idaho Power's part to hide information or mislead the reader.[4] There is there is no basis for such a conclusion. Table 3.1 and Figure 3.1 are appropriately labeled *Historical Capacity, Load and Customer Data*.[5] 2009 information was not yet available when the IRP was prepared.

Ms. Sayers' presentation begins by expressing confusion over the peak-hour load forecast data presented in Table 5.1 in the IRP.[6] Table 5.1 includes actual 2009 summer peak load data as this information was available prior to finalizing the IRP. Although the text presented below Table 5.1 states, "The median or expected case peak-hour load forecast predicts peak-hour load will grow from 3,160 MW in 2009 to 4,216 MW in 2029," the line at the bottom of Table 5.1 clearly indicates the growth rate is calculated for the years 2010-2029.

Ms. Sayers points out that the peak-hour load and resource balance presented in Appendix C-Technical Appendix (page 123) is missing a subtotal line for the Power Purchase Agreements section beginning in the year 2017.[7] Idaho Power confirmed this omission, which results in an error of 15 MW in the final Monthly Surplus/Deficit calculation shown in the IRP's Appendix C-Technical Appendix. This omission was simply in the printing of the Technical Appendix and not in the analysis. The IRP analysis actually included the 15 MW; however, when the table was sent to print, the subtotal line was omitted. Idaho Power agrees with Ms. Sayers that this omission is not material to the

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[4] Tr. 28:7 – 23 (Findley); Written Comments of Roger Findley.

[5] 2009 IRP at 24 (emphasis added).

[6] Tr. 43:18 – 44:18 (Sayers).

[7] Tr. 44:19 – 45:8 (Sayers).

results of the IRP; however, Idaho Power is providing a corrected version attached to its reply comments as Exhibit 1.

Ms. Sayers goes on to discuss a series of charts she prepared and used to support her conclusion that the B2H transmission line is not needed.[8] Without the underlying data used to prepare the charts, it is difficult for Idaho Power to comment on the validity of her analysis. Nonetheless, Idaho Power would like to point out that Ms. Sayers' assumption that the B2H transmission line would only serve the Treasure Valley is incorrect.[9] The IRP analysis is performed on a system-wide basis and the B2H transmission line would benefit all of Idaho Power's customers in Idaho and Oregon.

4. Idaho Power Appropriately Included the Hoku Load in its Load Forecast.

One commenter argues that the Company should not have included loads attributed to Hoku Scientific Inc. ("Hoku") in the load forecast given the Company's financial difficulties.[10] Idaho Power disagrees. Despite Hoku's reported financial challenges, Idaho Power continues to believe that it will be required to serve Hoku under the provisions of the current four-year energy services agreement. Hoku has recently indicated publicly that its ability to finance the continued construction of its Pocatello facility has improved following a large cash infusion provided by its new majority owner, Tianwei New Energy Holdings.

Idaho Power has completed construction of the substation and transmission line upgrades needed to serve Hoku's 82 MW load. As pointed out by the commenter, Hoku has made recent progress toward a fully operational polysilicon manufacturing plant. Hoku recently completed a successful demonstration of its ability to produce product at its

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[8]Tr. 48:13 – 17 (Sayers).

[9]Tr. 48:13 – 17 (Sayers).

[10]Written Comments of Patty Kennington.

Pocatello facility and has paid Idaho Power for the energy used to conduct that pilot.

The same commenter further suggests that Idaho Power should have considered serving Hoku's load with a resource located closer to the Pocatello facility to mitigate the impacts of line losses.[11] Idaho Power includes the impact of line losses as a standard adjustment in its resource planning process. Idaho Power recognizes that line losses must be factored into the IRP analysis in order to appropriately compare the cost of potential resources with different locations within or outside of the Company's service territory. The B2H transmission line was identified as a viable resource to meet future load in the Company's preferred resource portfolio with the impact of line losses factored into the analysis.[12]

5. The IRP Load Forecast Appropriately Accounts for Projected Economic Conditions.

As discussed above, the load forecast included in the IRP was specifically updated to reflect the most recent economic conditions. Nevertheless, several commenters at the Ontario Public Hearing suggested that the load forecast painted an unduly rosy picture of the economic future of Idaho Power's service area. In particular, one commenter presented historical data regarding housing starts and suggested that these served to undermine the IRP load forecast.[13] However, the list of housing starts by city/county presented by the commenter represents only a partial list of cities/counties in Idaho Power's service area. And while historical and projected housing starts are considered in the preparation of the IRP load forecast, many other factors are evaluated as indicated

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[11] Written Comments of Patty Kennington.

[12] The commenter also suggests that Hoku should consider using its own product to help serve a portion of its load. This, of course, is an economic and operational decision that can be made only by Hoku and not by Idaho Power in its IRP.

[13] Tr. 17:8 – 19:18 (Phillips).

above. The relevance of this data is further diminished because housing starts primarily influence the forecast of residential load and have no significant correlation to Idaho Power's other customer classes.

The load forecast Idaho Power used to develop its 2009 IRP is reliable. It is the result of a sound, industry-standard methodology, and is conservative in its estimates. It includes the most up-to-date economic data available, accounts for the current economic downturn, and incorporates loads the Company reasonably expects to serve.

B. The 2009 IRP Correctly Accounts For All Existing and Committed Resources.

In addition to criticizing the Company's load forecasts, Mr. Findley also argues that Idaho Power understated its committed resources in the IRP. Specifically, Mr. Findley's revision of the Company's Table 10.9 *Capacity Planning Margin* is based on numerous incorrect assumptions that lead Mr. Findley to faulty conclusions about the resources included in the IRP.[14] The following examples of errors are illustrative but by no means exhaustive.

First, Mr. Findley chooses to assign a peak-hour capacity factor of 32 percent to the 101 MW Elkhorn Valley Wind Project as opposed to the 5 percent Idaho Power included in Table 10.9.[15] The 2009 IRP assumes that new wind resources will operate at an annual average capacity factor of 32 percent. However, wind resources are assumed to operate at a capacity factor of 5 percent for peak-hour planning purposes. The use of a 5 percent peak-hour capacity factor for wind resources is a widely accepted assumption used by utilities in the Pacific Northwest.

Second, Mr. Findley assigns a peak-hour capacity value of 49 MW to the Shoshone Falls Upgrade Project, which is an upgrade of an existing Idaho Power hydroelectric

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[14] Tr. 28:24 – 35:4 (Findley).

[15] Tr. 33:8 – 18 (Findley).

facility.[16] While the upgrade will provide an additional 49 MW of nameplate generation, the actual energy generated from the upgrade is dependent on the availability of water. During the summer months when Idaho Power experiences peak loads, no additional water is anticipated to be available to generate beyond the capacity of the existing plant. Therefore, Idaho Power's value of zero for this upgrade is appropriate for capacity planning purposes.

Finally, Mr. Findley chooses to include an additional 29 MW of capacity from wind resources that is already accounted for in the CSPP (PURPA) line item.[17] While there are several additional incorrect assumptions made by Mr. Findley, these examples clearly invalidate the results he presents in his comments.[18]

C. Analysis of all Alternatives Shows that B2H Should Be Included in the Preferred Portfolio.

1. Forecasts of Impacts of Demand-Side Management Efforts on Load Indicates That They Will Not Be Sufficient to Replace B2H.

Several commenters take the position that the Company could obviate the need for B2H with increased demand-side management ("DSM")[19] efforts.[20] Similarly, a number of these commenters allege that Idaho Power has been deficient in seeking energy savings to date.[21] Both of these suggestions are unsupported by the facts.

First, it would not be possible for the Company to displace the need for B2H by increasing its efforts to save energy. In Idaho Power's IRP analysis, cost-effective energy

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[16] Tr. 31:10 – 13 (Findley).

[17] Tr. 31:14 – 17 (Findley).

[18] Tr. 35:1 – 4 (Findley).

[19] At various times commenters refer to conservation, energy efficiency, and/or demand-response programs. Each of these are components of the Company's overall DSM program.

[20] *See e.g.,* Written Comments of Evelyn Sayers.

[21] Tr. 39:3 – 15 (Penn).

efficiency and demand response are the first resources considered in the process. That is, prior to evaluating the need for traditional resources, including the B2H transmission line, all energy efficiency from existing programs and potential new cost-effective programs are removed from the load and resource balance that identifies future supply deficits. Under this approach, the Company ensures that first priority is given to all reasonably obtainable energy efficiency and demand response resources. Therefore, energy efficiency cannot replace the need for the B2H transmission line as all achievable potential energy savings have already been included in the plan as a fully committed resource.

Similarly, suggestions that the Company's DSM efforts have been deficient are without merit. One commenter in particular points out that Idaho Power's energy efficiency efforts lag behind the regional goals established by the NPCC's Sixth Power Plan and the achievements of its neighboring utilities in Washington and Oregon.[22] The facts, however, establish that Idaho Power's DSM activities have been appropriate and successful.

First, it is incorrect to suggest that Idaho Power is not meeting NPCC's conservation goals. The fact is that in 2009 the Company exceeded the goals contained in the Fifth Plan by approximately 30%, and is working aggressively to meet the goals set in the Sixth Plan. Specifically with respect to the Sixth Plan, Idaho Power worked closely with the NPCC in its development, in which a range of energy savings potential is identified and which includes a "regional check in" with appropriate target adjustments after two years due to the uncertainty surrounding the achievability of energy savings potential as laid out in the plan.[23]

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[22] Tr. 39:3 – 15 (Penn).

[23] The NPCC's methodology of forecasting conservation varies from Idaho Power's methods. In the IRP process, Idaho Power only includes energy savings potential from its existing incentive based programs and anticipated potential from programs and measures that are cost-effective, market ready, and readily available. The Council did not forecast potential demand savings from demand response programs from which Idaho Power obtains substantial peak reduction and on which Idaho Power spends considerable resources.

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With regard to the allegation that Idaho Power has displaced 6 percent of retail load with energy efficiency while "other utilities" have displaced between 13 percent and 18 percent,[24] Idaho Power does not know the source of these data. The Company contacted representatives from the NPCC in an attempt to validate the load displacement percentage numbers provided by the commenters. Council representatives involved with the preparation of the Sixth Power Plan were unable to reconcile the numbers with any of the Council's data or to validate the numbers in any way.

According to the U.S. Energy Information Administration "Annual Electric Power Industry Report for 2008"[25] Idaho Power was ranked sixth out of fifteen investor-owned utilities in the Western Electric Coordinating Council with energy savings accounting for 0.95 percent of retail energy sales. The range of annual percentage of savings varied from one company experiencing energy savings of 3.46 percent of annual retail savings to three utilities reporting no savings from energy efficiency.

The Company's success in DSM has been particularly strong. The Idaho Public Utilities Commission ("IPUC") recently found that Idaho Power had been "aggressively pursuing cost-effective demand-side management (DSM) options . . ." and that it had implemented such programs as reasonably as possible.[26]

The Company is firmly committed to pursuing all cost-effective DSM and is on the record in numerous proceedings in front of both the Idaho and Oregon Commissions stating this position. The Company's commitment is evidenced by its accomplishments from 2002 through 2009. Idaho Power's average annual increase in DSM investments since 2002 has been 50 percent while energy savings have averaged an increase of 40

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[24] Tr. 39:6 – 8 (Penn).

[25] Survey Form EIA-861

[26] *Re Idaho Power Company*, Case No. IPC-E-09-03, Order No. 30892 at 22 (Sept. 1, 2009).

percent annually. In 2009 Idaho Power's demand response programs decreased peak load by 218 MW, which is greater than the capacity of any of Idaho Power's gas-fired peaker plants and is equivalent to 7 percent of Idaho Power's all time system summer peak.

With the addition of new demand response programs and the modification of some existing programs, the 2009 IRP anticipates DSM programs will reduce peak-hour loads by 398 MW in the summer of 2015 when the B2H line is expected to be in-service. This level of load reduction is accounted for in the IRP load and resource balance. As previously pointed out, the IPUC considers Idaho Power's DSM efforts to be aggressive. The suggestion that the Company could displace B2H with additional energy savings—not already contemplated in the IRP—is undercut by the sheer magnitude of the savings that would be required.

2. Building an Additional Gas Plant Is Not a Viable or Cost Effective Alternative to B2H.

At the Public Hearing in Ontario on April 20, 2010, numerous comments were made indicating Idaho Power should pursue building additional natural gas resources as opposed to building the B2H transmission line.[27] The 2009 IRP addressed this option by analyzing portfolio 1.2 Gas Peaker. In Idaho Power's presentation to the Commission on February 23, 2010, the Company included the tipping point chart shown in Figure 3 below to present a direct comparison of the natural gas portfolio to the B2H portfolio.

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[27] *See e.g.*, Tr. 8: 9 – 15 (Marlette); Tr. 26:7 -9 (Faw); Tr. 52:11 – 16 (Pearson).

Figure 3

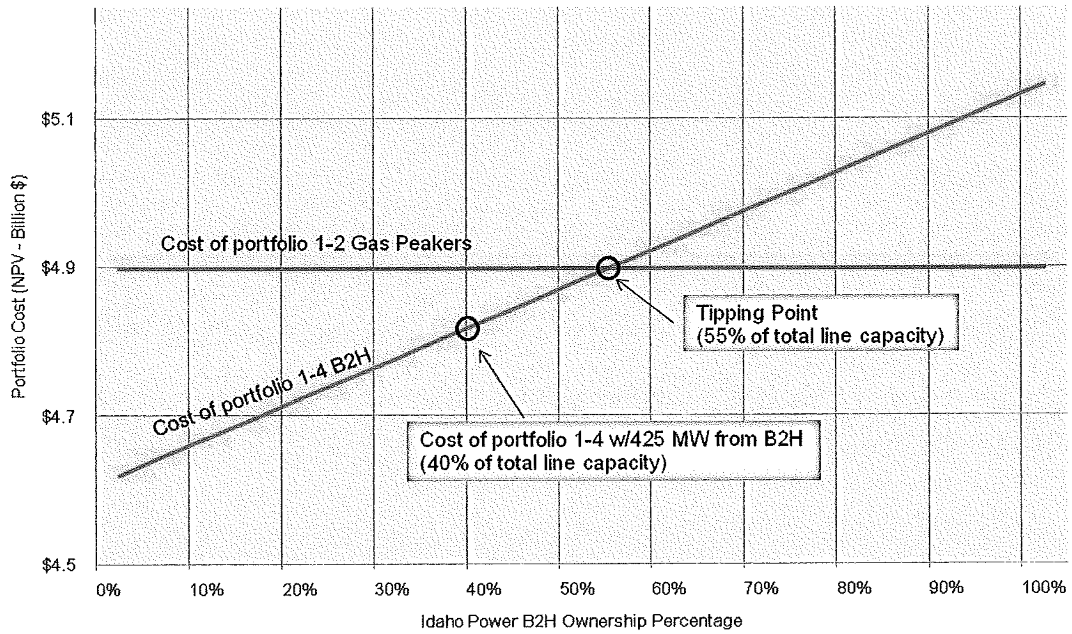

Figure 3 shows portfolio 1-4 B2H out-performed portfolio 1-2 Gas Peakers based on Idaho Power taking a 40 percent ownership share in the B2H line. The "tipping point" presented in Figure-3 indicates Idaho Power could take up to a 55 percent ownership share in the B2H line before the cost of the two portfolios would be the same. Figure 3 is the basis for Idaho Power including portfolio 1-2 Gas Peakers as an alternate portfolio in the 2009 IRP (see Table 10.5, page 116, 2009 IRP) in the event third party interest in the B2H line does not materialize as expected. Subsequent to the preparation and filing of the IRP, Idaho Power and PacifiCorp entered into an agreement to negotiate the joint ownership and development of the B2H line. A summary of this agreement is publicly available on Idaho Power's Open Access Same-time Information System ("OASIS") website.[28] This agreement and partnership increased confidence that actual third-party interest in the B2H line will materialize as set forth in the "tipping point" analysis of the IRP and confirms the inclusion of the B2H line in the Company's preferred resource portfolio.

[28] http://www.oatioasis.com/ipco/

In response to Staff's Data Request 16, which is attached as Exhibit 2, Idaho Power presented additional results regarding this tipping point chart. The response included the addition of different cost scenarios for both portfolio 1-2 Gas Peaker and portfolio 1-4 B-H.

3. Purchased Power is Not a Viable or Cost Effective Alternative to B2H.

At least one commenter argued that the B2H project could be avoided through additional purchased power.[29] Idaho Power agrees that power purchases are an important and cost-effective component of the Company's preferred resource plan. However, the logic in the suggestion that B2H could be avoided through increased power purchases is seriously flawed. The primary purpose of the B2H line is to provide the Company with the additional transmission capacity that will be necessary to import power from the Pacific Northwest power market. Currently, Idaho Power does not have adequate transmission capacity to increase its on-peak power purchases on the western side of its system. B2H is the most cost-effective and viable option for Company to access the Northwest power market. Further, purchasing power from the eastern side of Idaho Power's system is not a viable alternative to B2H because of the lack of liquidity in the east-side markets and the long-term risk of price escalation.

D. Company's Need to Build to Accommodate Wheeling Requests is Legitimate.

One of the commenters argued that the Company has no obligation to accommodate wheeling requests by third parties and that such requests cannot serve to justify the need for B2H.[30] This position is incorrect.

Federal law requires Idaho Power to provide wheeling services on a non-discriminatory basis and this requires the construction of a transmission system that ensures reliable and economic service to transmission customers.[31] Toward this end, the

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[29] Tr. 47:6 – 15 (Sayers).

[30] Tr. 14:18 – 22 (Findley).

[31] *See* 16 U.S.C. § 824d and 824e; *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public*

Federal Energy Regulatory Commission ("FERC") adopted a *pro forma* Open Access Transmission Tariff ("OATT") that includes terms and conditions for non-discriminatory transmission service.[32] Utilities must provide access to their systems pursuant to their OATTs and must also take transmission service for its own wholesale sales and purchase of electricity under the same tariffs.[33] This ensures that utilities cannot discriminate in favor of their resources by limiting access to their transmission system by other transmission customers.[34]

FERC has found, however, that providing access to the transmission system on uniform terms and conditions is insufficient to ensure nondiscrimination. Specifically, FERC has noted that the ability and incentive to discriminate increases as the transmission system becomes more congested.[35] In light of this concern and coupled with its conclusion that the national transmission system is in "critical need [of] new transmission infrastructure," FERC adopted reforms to its *pro forma* OATT to "ensure that transmission infrastructure is constructed . . . on a nondiscriminatory basis and is

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Utilities and Transmitting Utilities, Docket Nos. RM95-8-000 and RM94-7-00161, Order No. 888 at 6, FR 21,540, 1996 WL 239663 (F.E.R.C 1996) (FERC's rules are intended to "remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce") (hereinafter "Order No. 888"); *Preventing Undue Discrimination and Preference in Transmission Service*, Docket Nos. RM05-17-000 and RM05-25-000; Order No. 890 at 40 (F.E.R.C. 2007) (transmission system must be "sufficient to support reliable and economic service to all eligible customers") (hereinafter "Order No. 890").

[32] Order No. 888 at 6-7.

[33] Order No. 888 at 7.

[34] Order No. 888 at 6. Although Idaho Power must accommodate requests for wheeling services pursuant to its OATT, it may reserve certain transmission capacity for its own use. Specifically, capacity necessary for native load growth and network transmission load growth that is reasonably forecasted may be reserved. Order No. 88 at 92. This reserved capacity, however, "must be posted on the OASIS and made available to others through the capacity reassignment requirements" if it is not currently needed and until it is actually needed and used. *Id.*

[35] Order No. 890 at 37.

otherwise sufficient to support reliable and economic service to all eligible customers."[36] Thus, Idaho Power's OATT, which incorporates the transmission infrastructure standards in FERC's *pro forma* OATT, requires it to provide reliable and economic service to its transmission customers and construct transmission infrastructure to ensure these standards are met.[37]

Moreover, FERC's *pro forma* OATT also includes a provision requiring transmission providers to "expand or upgrade [their] system" to accommodate requests for point-to-point service if redispatch of the system is not economical to relieve system constraints and allow efficient and reliable transmission.[38] Under Section 15.4 of the *pro forma* OATT:

> "when a transmission provider cannot accommodate a request for point-to-point transmission because of insufficient capability on its system, it will 'use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service.'"[39]

The B2H transmission line is integral to Idaho Power's OATT compliance. Construction of B2H will relieve the transmission system of its current congestion problems and reduce the risk of transmission outages that cause reliability concerns for the Company's transmission customers. Moreover, construction of the transmission line will ensure that Idaho Power is able to meet the increasing requests for transmission as required by FERC.

Idaho Power has received requests to commence transmission service representing more than 4,000 MW between 2005 and 2014 on the Idaho Northwest transmission path.

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[36] Order No. 890 at 40. These reforms involve primarily greater transparency and coordination in the transmission infrastructure planning process.

[37] *See* Idaho Power Company FERC Electric Tariff, First Revised Volume No. 6, Attachment K; Order No. 890 at App. C (*pro forma* OATT).

[38] Order No. 890 at 235-236.

[39] *Id.*

Of the 4,000 MW of service requests, only 133 MW were granted up through 2007 due to the limited available transmission capacity of the existing system. There are currently active transmission service requests being studied that are expected to commence operations when the proposed Boardman to Hemingway project is completed.

It should be noted that utility customers—not shareholders—benefit from wheeling revenues. Many of the commenters have suggested otherwise, arguing that the Company's primary motive for building B2H is to generate wheeling revenues that will create profits for the Company.[40] This claim is inconsistent with the basic cost assignment principles applied by Idaho Power in its standard electric utility rate making process. Under the standard electric utility rate making process applied by Idaho Power, the Company develops rates to recover a "return on" and a "return of" its investment in facilities required to service customers (rate base) as well as the recovery of the associated operations and maintenance expense. However, as part of this process, customer rates are offset by any "other" revenue generated by those facilities, including transmission wheeling revenue. That is, wheeling revenue actually reduces the amount of revenue required from retail customers, rather than resulting in additional earnings for shareowners. The only potential profit component associated with the B2H transmission line will be associated with the allowed rate of return on the undepreciated plant investment over its useful life. This is the same for all types of facilities, transmission or otherwise.

E. Regional Planning is Legitimately Considered as Part of Need.

Several of the commenters have argued that B2H is not needed because it is being built to serve third party and out-of-state interests, and because it will not benefit Oregonians.[41] Neither argument has merit.

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[40] Tr. 12:23 – 13:1 (Findley).

[41] Tr. 53:2 – 8 (Pearson).

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First of all, given the interconnected nature of the national electricity grid, the need for any particular transmission line cannot be considered in a vacuum. This principle was established by the Commission in its 1976 order granting a certificate of public convenience and necessity ("CPCN") to Pacific Power & Light ("PP&L") to construct a 500 kV transmission line from southern Idaho to Medford, Oregon.[42] In that case PP&L argued that the proposed transmission line was needed to transmit energy from its Wyoming generating plant to customers in the western portion of its system. In addition to serving PP&L's own customers, the Commission noted that the proposed transmission line would also increase capacity, stability, and reliability for the Pacific Northwest Transmission Grid and Northwest Power Pool.[43] PP&L presented the Commission with alternatives to the proposed line and the Commission found that the alternatives "would not yield the same advantages to the regional and inter-regional transmission grids and inter-connected power systems as the proposed transmission line."[44] The Commission issued the CPCN because it concluded the proposed transmission line was necessary for PP&L to provide adequate service at reasonable rates, justified in the public interest, and the public convenience and necessity required it to be constructed along the route approved by the Commission.[45] Thus, the Commission's analysis focused not only on Oregon customers but also on the necessity to the regional transmission grid.

Here, Idaho Power's Oregon customers benefit from the Commission's regional planning because it allows Idaho Power to better import power from the Pacific Northwest

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[42] *Application of Pacific Power & Light Co. for Certificate of Public Convenience and Necessity*, Docket UF 3182, Order No. 76-359 (May 28, 1976) (343 of the 478 miles of proposed transmission line were in Oregon) (hereinafter "Order No. 76-359).

[43] Order No. 76-359 at 4.

[44] Order No. 76-359 at 5.

[45] Order No. 76-359 at 6. Although the Commission approved the project in this order, the full route was not approved until February 22, 1979. *See* Order 79-112.

power market—a market that is very liquid with a high number of participants and transactions. This ensures that rates remain just and reasonable and ensures that Idaho Power can continue to provide safe, reliable, and efficient service to its Oregon customers.

Moreover, contrary to many of the public and intervenor comments, B2H will in fact provide direct benefits to Oregon customers by serving increasing loads in Idaho Power's Eastern Oregon service territory. Just this last February Mission West Properties, Inc. and CDH Consulting announced that they would be building a new data center located in Ontario, Oregon. The planned data center will be sized up to 300,000 square feet and will include a 62 MVA onsite power station. This is precisely the type of new load that the Company must plan for.

F. Response to Renewable Northwest Project Comments

RNP is the only intervenor to file formal comments with the Commission on the Company's 2009 IRP. Idaho Power would like to thank RNP for its interest and participation in the development of the 2009 IRP. While not officially represented on the IRPAC, RNP representatives attended many of the IRPAC meetings and provided input throughout the process of preparing the plan.

Idaho Power appreciates RNP's positive comments related to the analyses of future carbon regulation scenarios in the IRP. On that subject RNP states: "Idaho Power's IRP strategically accounts for the cost, risk and environmental concerns associated with future limits on greenhouse gas emissions."[46] One of Idaho Power's primary goals in preparing the IRP is to balance cost, risk, and environmental concerns, for all aspects of resource planning.

RNP's positive comments are tempered by concern over the future operation of the Boardman coal-fired plant. Idaho Power is a 10 percent owner of the project which

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[46] *Re Idaho Power Company 2009 Integrated Resource Plan*, Docket LC 50, Comments of Renewable Northwest Project at 1 (Apr. 20, 2010).

provides approximately 55 aMW of generation for Idaho Power's customers. Portland General Electric, the majority owner and operator of the project, evaluated several scenarios in its 2009 IRP regarding possible closure dates and at present, there is still much uncertainty regarding the future operation of the plant.

In the coal curtailment scenario (Waxman-Markey) analyzed in Idaho Power's 2009 IRP, more than 100 MW of Idaho Power's coal generation is curtailed prior to 2014—which is the earliest date under consideration for the closure of the Boardman plant. In addition, if the Boardman plant is closed the transmission capacity used to bring energy from Boardman to Idaho Power's customers would be available to import energy from the Pacific Northwest power market. For these reasons, Idaho Power believes there is low risk associated with the treatment of the Boardman plant in the 2009 IRP. Idaho Power anticipates more definitive information will be available regarding the future of the Boardman plant which can be incorporated in the Company's 2011 IRP.

RNP also provided comments on the disposition of renewable energy certificates ("REC") that Idaho Power is currently acquiring. Idaho Power is in a unique situation because it has customers in Oregon where there is a renewable portfolio standard ("RPS"), and in Idaho which does not have an RPS.

Under the Oregon RPS, Idaho Power is categorized as a "smaller utility" which results in a 10 percent requirement beginning in 2025. In the 2009 IRP, Idaho Power assumes a federal renewable electricity standard ("RES") will be passed in the near future. The preferred portfolio and all portfolios analyzed in the IRP were designed to meet a federal RES, which is expected to substantially exceed Idaho Power's RPS requirements in Oregon.

Currently, a docket is open at the IPUC to address the disposition of Idaho Power's RECs. In December 2009, Idaho Power submitted a plan to the IPUC which outlines Idaho Power's strategy regarding RECs. The general strategy presented in the plan is to continue to acquire long term rights to RECs in anticipation of a federal RES, but to sell them in the short term until a requirement exists. This strategy benefits Idaho Power's customers as revenues from REC sales are used to reduce customer rates in the short term, and risk is lowered by acquiring long term rights to RECs in order to comply with a federal RES.

III. CONCLUSION

Idaho Power thanks all commenters for their interest and participation in this IRP docket. With respect to the criticisms of the 2009 IRP's inclusion of the B2H project in the preferred portfolio, Idaho Power submits that the criticisms are without merit and the Commission should acknowledge the IRP as filed.

Respectfully submitted this 19th day of May, 2010.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Idaho Power Company's Response to
Intervenor and Public Comments in its
2009 Integrated Resource Plan

Exhibit No. 1

May 19, 2010

IDAHO POWER®
An IDACORP Company

March 22, 2010

Subject: Docket No. LC 50
Idaho Power Company's Response to Staff's Data Request 16

STAFF'S DATA REQUEST NO. 16:

Please conduct a construction cost risk analysis for the Boardman to Hemingway transmission line. This analysis should include a "tipping point" calculation with regard to portfolio 1-2. At a minimum, this risk analysis should include the following scenarios: worst case construction costs in portfolio 1-4 vs. low natural gas prices in portfolio 1-2, best case construction costs in 1-4 vs. high natural gas prices in 1-2, and best case construction costs in 1-4 vs. low natural gas prices in 1-2. Please provide your analysis in an Excel workbook with all formula's intact and references cited.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 16:

The construction costs used in the tipping point chart represent a high estimate and not necessarily an unbounded "worst case." The construction costs are included on the attached Excel file entitled *B2H 500 kV Project Estimates High.*

The attached Excel spreadsheet, *Tipping Point Chart*, shows the risk analysis with the following scenarios: worst case construction costs in portfolio 1-4 vs. low natural gas prices in portfolio 1-2, best case construction costs in portfolio 1-4 vs. high natural gas prices in portfolio 1-2, and best case construction costs in portfolio 1-4 vs. low natural gas prices in portfolio 1-2.

To be consistent with the presentation of the tipping point chart presented in the Company's Response to Staff's Data Request No. 14, the second ten years (2020-2029) need to be included in the chart. Additionally, no low cost natural gas price AURORA runs were used in completing the 2009 Integrated Resource Plan. These changes require the preferred portfolio 2-4 to be run in AURORA with portfolio 1-2 as the starting point and removing the transmission expansion assumed in portfolio 1-4.

The following Excel files supporting the tipping point chart calculations are included with this response: *IRP Transmission Rate Est with B2H_High_Estimate* and *IRP Transmission Rate Est with B2H_ Transmission Range of Costs High.*

Attachment 1 - Response Staff DR 16

Boardman - Hemingway 500 kV Line Estimate - High				
Conceptual Level Project Cost Estimate Lines Contingency %:	30%			
AFUDC %:	5%			
Gen w/o overhead %:	10%			
March 2010 IPCo Share %:	100%			
Location & Description	**Transmission Line Costs, $**	**Total Cost, $**	**Total Cost/Mile, $**	**Commitment Date**
Transmission Lines:				
Boardman - Hemingway 500 kV Line				
Line length (miles):	300			
Permitting & Engineering Price	$ 30,000,000	$ 43,500,000		Apr-10
ROW Price/mile	$ 150,000	$ 65,250,000	$ 217,500	Jan-12
Mitigation Price/mile	$ 150,000	$ 65,250,000	$ 217,500	Jun-13
Lattice Structure Material Price/mile:	$ 500,000	$ 217,500,000	$ 725,000	Jun-12
Lattice Structure Labor Price/mile:	$ 800,000	$ 348,000,000	$ 1,160,000	Jun-13
Subtotal ==>	**$ 510,000,000**			
Contingency:	$ 153,000,000			
AFUDC:	$ 25,500,000			
IPC Capital work order overhead:	$ 51,000,000			
Substations	$ 56,702,685			
TOTAL ESTIMATED PROJECT COST ==>	**$ 796,202,685**			
TOTAL PROJECT COST/MILE ==>	**$ 2,654,009**			
Notes:				
1. All estimates are conceptual level estimates.				
2. Commitment dates are preliminary and based on June 2015 in-service date.				

Attachment 2 - Response Staff DR 16

Transmission Rate Approximation

Annual Revenue Requirements

Existing	$	106,566,650		
New Project Capital	$	600,000,000		
Ratio of New Revenue Requirements/New Capital		0.160		
New Revenue Requirements = (New Capital) * (ratio)	$	96,041,761		
Existing Revenue Credits		(17,510,193)		
Existing Revenue Requirements		89,056,456		
New Revenue Requirements	$	185,098,225		

System Use

Existing System Peak Demand - MW		5,627		
Additional System Demand - Project fully subscribed		3000		
New System Demand - Project fully subscribed		8,627		

Point-To-Point Transmission Rate

Existing Rate - $/kW-yr	$	15.83		
New Rate without Additional Demand - $/kW-yr	$	32.90		
New Rate with Project fully subscribed - $/kW-yr	$	21.46		

Point-To-Point Revenue Adjustments (changes to Revenue Credits)

Existing uses (assume same uses at new rate)	$	(18,883,634)		
New fully subscribed uses	$	(64,370,174)		

Network Transmission Revenue Requirements (Assessments)

To be allocated by load ratio share across all Network Customers

Existing	$	89,056,456		0
With New Project - no new uses	$	166,214,586	$	77,158,130
With New Project - fully subscribed	$	101,844,412	$	12,787,955

Portfolio 1-1 (Large 200 MW at Langley)
Back bone Only

2010		0		0	
2011		0		0	
2012		0		0	
2013		0		0	
2014		0		0	
2015	$	4,496,303		0	
2016	$	4,496,303		0	
2017	$	4,496,303		0	
2018	$	4,496,303		0	
2019	$	4,496,303		0	$13,163,761
2020	$	4,496,303	$	4,496,303	
2021	$	4,496,303	$	4,496,303	
2022	$	4,496,303	$	4,496,303	
2023	$	4,496,303	$	4,496,303	
2024	$	4,496,303	$	4,496,303	
2025	$	4,496,303	$	4,496,303	
2026	$	4,496,303	$	4,496,303	
2027	$	4,496,303	$	4,496,303	
2028	$	4,496,303	$	4,496,303	
2029	$	4,496,303	$	4,496,303	$16,098,665.14
		$29,262,425.74			$29,262,425.74

Portfolio 1-2(FP 340 MW at Langley)
Back bone Only

2010		0		0	
2011		0		0	
2012		0		0	
2013		0		0	
2014		0		0	
2015	$	3,749,520		0	
2016	$	3,749,520		0	
2017	$	3,749,520		0	
2018	$	3,749,520		0	
2019	$	3,749,520		0	$10,977,415
2020	$	3,749,520	$	3,749,520	
2021	$	3,749,520	$	3,749,520	
2022	$	3,749,520	$	3,749,520	
2023	$	3,749,520	$	3,749,520	
2024	$	3,749,520	$	3,749,520	
2025	$	3,749,520	$	3,749,520	
2026	$	3,749,520	$	3,749,520	
2027	$	3,749,520	$	3,749,520	
2028	$	3,749,520	$	3,749,520	
2029	$	3,749,520	$	3,749,520	$13,424,865.36
		$24,402,281.29			$24,402,281.29

	Portfolio 1-3 (250 MW) Fully Subscribed	Outbound not sold Fully Subscribed	100% IPC No Other Users	NPV					
2010	0	0	0	0	0	0			
2011	0	0	0	0	0	0			
2012	0	0	0	0	0	0			
2013	0	0	0	0	0	0			
2014	0	0	0	0	0	0			
2015	$ 13,210,615	$ 18,923,915	$ 85,354,729	0	0	0			
2016	$ 13,210,615	$ 18,923,915	$ 85,354,729	0	0	0			
2017	$ 13,210,615	$ 18,923,915	$ 85,354,729	0	0	0			
2018	$ 13,210,615	$ 18,923,915	$ 85,354,729	0	0	0			
2019	$ 13,210,615	$ 18,923,915	$ 85,354,729	0	0	0	$28,670,525	$55,403,269	$249,351,759
2020	$ 13,210,615	$ 18,923,915	$ 85,354,729	$ 13,210,615	$ 18,923,915	$ 85,354,729			
2021	$ 13,210,615	$ 18,923,915	$ 85,354,729	$ 13,210,615	$ 18,923,915	$ 85,354,729			
2022	$ 13,210,615	$ 18,923,915	$ 85,354,729	$ 13,210,615	$ 18,923,915	$ 85,354,729			
2023	$ 13,210,615	$ 18,923,915	$ 85,354,729	$ 13,210,615	$ 18,923,915	$ 85,354,729			
2024	$ 13,210,615	$ 18,923,915	$ 85,354,729	$ 13,210,615	$ 18,923,915	$ 85,354,729			
2025	$ 13,210,615	$ 18,923,915	$ 85,354,729	$ 13,210,615	$ 18,923,915	$ 85,354,729			
2026	$ 13,210,615	$ 18,923,915	$ 85,354,729	$ 13,210,615	$ 18,923,915	$ 85,354,729			
2027	$ 13,210,615	$ 18,923,915	$ 85,354,729	$ 13,210,615	$ 18,923,915	$ 85,354,729			
2028	$ 13,210,615	$ 18,923,915	$ 85,354,729	$ 13,210,615	$ 18,923,915	$ 85,354,729			
2029	$ 13,210,615	$ 18,923,915	$ 85,354,729	$ 13,210,615	$ 18,923,915	$ 85,354,729	$17,299,585.27	$67,755,614.04	$305,600,005.44
						$			
	$85,976,109.80	$123,158,883.52					$85,976,109.80	$123,158,883.52	$555,497,794.76

High Estimate

	Portfolio 1-4 (425 MW) Fully Subscribed	Outbound not sold Fully Subscribed			NPV	NPV outbound Not Sold
2010	0	0	0	0		
2011	0	0	0	0		
2012	0	0	0	0		
2013	0	0	0	0		
2014	0	0	0	0		
2015	$ 20,179,982	$ 40,359,964	0	0		
2016	$ 20,179,982	$ 40,359,964	0	0		
2017	$ 20,179,982	$ 40,359,964	0	0		
2018	$ 20,179,982	$ 40,359,964	0	0		
2019	$ 20,179,982	$ 40,359,964	0	0	$59,080,636	$118,161,273
2020	$ 20,179,982	$ 40,359,964	$ 20,179,982	$ 40,359,964		
2021	$ 20,179,982	$ 40,359,964	$ 20,179,982	$ 40,359,964		
2022	$ 20,179,982	$ 40,359,964	$ 20,179,982	$ 40,359,964		
2023	$ 20,179,982	$ 40,359,964	$ 20,179,982	$ 40,359,964		
2024	$ 20,179,982	$ 40,359,964	$ 20,179,982	$ 40,359,964		
2025	$ 20,179,982	$ 40,359,964	$ 20,179,982	$ 40,359,964		
2026	$ 20,179,982	$ 40,359,964	$ 20,179,982	$ 40,359,964		
2027	$ 20,179,982	$ 40,359,964	$ 20,179,982	$ 40,359,964		
2028	$ 20,179,982	$ 40,359,964	$ 20,179,982	$ 40,359,964		
2029	$ 20,179,982	$ 40,359,964	$ 20,179,982	$ 40,359,964	$72,252,864.07	$144,505,728.15
	$131,333,501.96	$262,667,003.93			$131,333,501.96	$262,667,003.93

Expected Estimate

	Portfolio 1-4 (425 MW) Fully Subscribed	Outbound not sold Fully Subscribed			NPV	NPV outbound Not Sold	
2010	0	0	0	0			
2011	0	0	0	0			
2012	0	0	0	0			
2013	0	0	0	0			
2014	0	0	0	0			
2015	16520081	32261593	0	0			
2016	16520081	32261593	0	0			
2017	16520081	32261593	0	0			
2018	16520081	32261593	0	0			
2019	16520081	32261593	0	0	48315599.79	94451794.49	249831793.1
2020	16520081	32261593	16520081	32261593			
2021	16520081	32261593	16520081	32261593			
2022	16520081	32261593	16520081	32261593			
2023	16520081	32261593	16520081	32261593			
2024	16520081	32261593	16520082	32261593			
2025	16520081	32261593	16520081	33261593			
2026	16520081	32261593	16520081	32261593			
2027	16520081	32261593	16520081	32261593			
2028	16520081	32261593	16520081	32261593			
2029	16520081	32261593	16520083	32261593	59148872.33	115510138.6	305606005.7
	107524472.1	209961933.1			107514472.1	209961933.1	555437794.8

Attachment 2 - Response Staff DR 16

IDAHO POWER COMPANY
RATE CALCULATION
12 Months Ended 12/31/2008

		Source	Amount	B2H	Expense Allocation Ratio for new Transmission Plant			
				600,000,000	100%	50%	0%	
	TRANSMISSION RATE BASE							
1	Transmission Plant (excluding Asset Retirement Costs)		742,870,924					
2	Generator Step Up Facilities		(16,703,791)					
3	LGI's		(821,682)					
4	Account 252-Transmission (Net)		(2,310,431)					
5	General Plant (excluding Asset Retirement Costs)		30,744,244					
6	Intangible Plant		6,961,612					
7	Transmission Plant Held For Future Use		676,535					
8	General Plant Held For Future Use		112,758					
9	Transmission Depreciation Reserve (Acct 108) (excluding Asset Retirement Costs)		(230,292,212)					
10	Transmission Depreciation Reserve Generator Step-Ups		9,787,710					
11	Transmission Depreciation Reserve LGI's		93,681					
12	General Plant Depreciation Reserve (excluding Asset Retirement Costs)		(11,660,762)					
13	Amortization of Utility Plant		2,379,351					
14	ADIT Allocated to Trans		(49,151,423)					
15	ADIT Allocated to Gen & Intang.		(2,555,053)					
16	Transmission Related Prepayments		1,252,469					
17	Transmission Materials & Supplies		10,342,021					
18	Transmission Cash Working Capital		4,644,612					
19	Unamortized RTO Development Costs		$2,384,070					
20	Transmission Rate Base	(20) + B2H	498,754,634	1,098,754,634				
21								
22	**RETURN AND ASSOCIATED INCOME TAXES**							
23	Overall Return		0.08203					
24	Composite Income Tax (Federal and State)		0.03427					
25	Return and Income Taxes	(20)*((23)+(24))	58,005,164	127,785,164				
26								
27								
28	**EXPENSES**							
29	Deprec Expense: Transmission		14,609,825		14,609,825			
30	Deprec Expense: General Plant		1,654,697			1,654,697		
31	Depreciation Expense: Intangible Plant		696,024			696,024		
32	Amort of ITC (Acct 411.4)		430,116			430,116		
33	O&M Expense: Transmission		23,196,223			23,196,223		
34	Less Account 561 (Load Dispatching)		(2,883,995)			(2,883,995)		
35	Less: Account 565 (Transmission of Electricity By Others)		(7,250,299)			(7,250,299)		
36	O&M Expense: A&G		13,960,670			13,960,670		
37	Taxes Other than Income:		3,003,630		3,003,630			
38	Amortization of RTO Development Costs		$922,866				$922,866	
39	Interest Expense (Network Upgrade Prepayments)		$221,728				$221,728	
40	Transmission Expense	Sum (29) Thru (39)	48,561,486	74,823,254	17,613,456	29,803,436	1,144,594	
41	Gross Transmission Revenue Requirement	(25) + (40))	106,566,650	202,608,418	31,839,445	41,839,216	1,144,594	
	Net Rev Req of New Project			96,041,768				recovery from all Network Transmission Customers
			0.14	0.16				ratio of net revenue requirement to new capital investment
43	Transmission Revenue Credits	Schedule 4	(17,510,193)	(17,510,193)				
44								
45	Net PTP Transmission Revenue Requirement	(41) - (43)	89,056,456	185,098,225				
46								
47	**System Peak Demand - MW**	Schedule 5	5,627	5,627				assumes no additional service
48								
49	Annual Rate $/kW per year	(45)/((47)*1000)	15.83	32.90				new transmission rate with no additional service
	New Service			3,000				assume new transmission service - fully subscribed project
				8,627				new system peak demand
	Annual Rate $/kW per year			21.46				new transmission rate with project fully subscribed
	Revenue from new service			64,370,174				
	New Net Rev Req of New Project - if fully subscribed			31,671,594				recovery from all Network Transmission Customers

Attachment 2 - Response Staff DR 16

IDAHO POWER COMPANY
RATE CALCULATION
12 Months Ended 12/31/2008

	TRANSMISSION RATE BASE
1	Transmission Plant (excluding Asset Retirement Costs)
2	Generator Step Up Facilities
3	LGI's
4	Account 252-Transmission (Net)
5	General Plant (excluding Asset Retirement Costs)
6	Intangible Plant
7	Transmission Plant Held For Future Use
8	General Plant Held For Future Use
9	Transmission Depreciation Reserve (Acct 108) (excluding Asset Retirement Costs)
10	Transmission Depreciation Reserve Generator Step-Ups
11	Transmission Depreciation Reserve LGI's
12	General Plant Depreciation Reserve (excluding Asset Retirement Costs)
13	Amortization of Utility Plant
14	ADIT Allocated to Trans
15	ADIT Allocated to Gen & Intang
16	Transmission Related Prepayments
17	Transmission Materials & Supplies
18	Transmission Cash Working Capital
19	Unamortized RTO Development Costs
20	Transmission Rate Base
21	
22	**RETURN AND ASSOCIATED INCOME TAXES**
23	Overall Return
24	Composite Income Tax (Federal and State)
25	Return and Income Taxes
26	
27	
28	**EXPENSES**
29	Deprec Expense: Transmission
30	Deprec Expense: General Plant
31	Depreciation Expense: Intangible Plant
32	Amort of ITC (Acct 411.4)
33	O&M Expense: Transmission
34	Less Account 561 (Load Dispatching)
35	Less: Account 565 (Transmission of Electricity By Others)
36	O&M Expense: A&G
37	Taxes Other than Income:
38	Amortization of RTO Development Costs
39	Interest Expense (Network Upgrade Prepayments)
40	Transmission Expense
41	Gross Transmission Revenue Requirement
42	
43	Transmission Revenue Credits
44	
45	Net PTP Transmission Revenue Requirement
46	
47	**System Peak Demand - MW**
48	

Attachment 2 - Response Staff DR 16

49 Annual Rate $/kW per year
50 Monthly Rate $/kW per month
51 Weekly Rate $/kW per week
52 Daily Rate $/kW per day (Mon-Sat)
53 Daily Rate $/kW per day (Sunday)
54 Hourly Rate $/MW per hour (Peak)
55 Hourly Rate $/MW per hour (Off-Peak)

Attachment 2 - Response Staff DR 16

Source	Amount
FF1 p207 58(g) - 57(g)	742,870,924
Schedule 7	(16,703,791)
Schedule 8	(821,682)
Schedule 9	(2,310,431)
Schedule 1	30,744,244
Schedule 1	6,961,612
FF1 p214 4d + 5d + 12d	676,535
Schedule 1	112,758
FF1 p 219 25(b) - 108.100 = 0	(230,292,212)
Schedule 7	9,787,710
Schedule 8	93,681
Schedule 1	(11,660,762)
Schedule 1	2,379,351
Schedule 1	(49,151,423)
Schedule 1	(2,555,053)
Schedule 1	1,252,469
Schedule 1	10,342,021
Schedule 1	4,644,612
OATT Attach H, 3.1.1.11(c)	$2,384,070
Sum (1) Thru (19)	498,754,634
Schedule 6	0.08203
Schedule 6	0.03427
(20)*((23)+(24))	58,005,164
Schedule 2	14,609,825
Schedule 2	1,654,697
Schedule 2	696,024
Schedule 2	430,116
Schedule 2	23,196,223
FF1 p 321 84b to 92b	(2,883,995)
FF1 p 321 96b	(7,250,299)
Schedule 2	13,960,670
Schedule 2	3,003,630
OATT Attach H, 3.7	$922,866
Schedule 9	$221,728
Sum (29) Thru (39)	48,561,486
(25) + (40))	106,566,650
Schedule 4	(17,510,193)
(41) - (43)	89,056,456
Schedule 5	5,627

Attachment 2 - Response Staff DR 16

(45)/((47)*1000)	15.83
(49) / 12	1.3192
(49) / 52	0.3044
(51) / 6	0.0507
(51) / 7	0.0435
(49)*1000 / 4896	3.23
(49)*1000 / 8760	1.81

Attachment 3 - Response Staff DR 16

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 1-1

Project		Capital Cost
Large Aero 200 MW at Langley G	$	22,000,000
200 MW Solar	$	4,500,000

Annual Revenue Requirements

Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**26,500,000**
New Revenue Requirements for Project(s)	$	4,241,845
New Net Revenue Requirements	$	93,298,301

System Use (in MW)

Existing System Peak Demand	5,627
Future additional IPC Network Use	**400**
New System Demand—Including new uses	6,027

Point-To-Point Transmission Rate

a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	15.48

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)

Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	383,526

Network Transmission Revenue Requirements

a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future		
BPA Load Ratio Share	$	4,144,207
Long-Term PTP Revenue	$	7,214,205
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	75,197,067
Net change	**$**	**4,496,303**

Attachment 3 - Response Staff DR 16

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 1-2

Project		Capital Cost
Two 170 MW Peakers at Langley	$	22,000,000

Annual Revenue Requirements		
Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**22,000,000**
New Revenue Requirements for Project(s)	$	3,521,532
New Net Revenue Requirements	$	92,577,988

System Use (in MW)	
Existing System Peak Demand	5,627
Future additional IPC Network Use	**340**
New System Demand—Including new uses	5,967

Point-To-Point Transmission Rate		
a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	15.52

Point-To-Point Revenue Adjustments (Incremental change to Existing Revenue Credits)		
Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	344,857

Network Transmission Revenue Requirements		
a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future		
BPA Load Ratio Share	$	4,154,388
Long-Term PTP Revenue	$	7,230,494
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	74,450,284
Net change	**$**	**3,749,520**

Attachment 3 - Response Staff DR 16

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 1-3 with additional 3rd party subscription

Project		Capital Cost
B2H 11% Owned by IPCo (250/2300)	$	65,217,391
Two 100MW Aeros at Langley	$	22,000,000

Annual Revenue Requirements		
Existing Revenue Requirements..	$	106,566,650
Existing Revenue Credits..	$	(17,510,193)
Existing Net Revenue Requirements..	$	89,056,456
New Project Capital	**$**	**87,217,391**
New Revenue Requirements for Project(s)................................	$	13,960,854
New Net Revenue Requirements..	$	103,017,310

System Use (in MW)	
Existing System Peak Demand..	5,627
Future additional IPC Network Use	**450**
New System Demand—Including new uses..............................	6,077

Point-To-Point Transmission Rate		
a) Existing Rate—$/kW-yr..	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr................................	$	16.95

Point-To-Point Revenue Adjustments (Incremental change to Existing Revenue Credits)		
Change in existing uses (increase > 100%)................................		100%
Existing uses adjusted at new rate b)..	$	(1,244,978)

Network Transmission Revenue Requirements		
a) Existing		
BPA Load Ratio Share..	$	4,237,114
Long-Term PTP Revenue..	$	7,375,757
Legacy Contract Revenue..	$	6,742,822
Assigned to IPC Retail Load Service..	$	70,700,764
b) Future - B2H with additional participation		
BPA Load Ratio Share..	$	4,462,935
Long-Term PTP Revenue..	$	7,900,174
Legacy Contract Revenue..	$	6,742,822
Assigned to IPC Retail Load Service..	$	83,911,380
Net change	**$**	**13,210,615**

Attachment 3 - Response Staff DR 16

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 1-3 without additional 3rd party subscription

Project		Capital Cost
B2H 22% Owned by IPCo (500/2300)	$	130,434,783
Two 100MW Aeros at Langley	$	22,000,000

Annual Revenue Requirements		
Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**152,434,783**
New Revenue Requirements for Project(s)	$	24,400,177
New Net Revenue Requirements	$	113,456,633

System Use (in MW)	
Existing System Peak Demand	5,627
Future additional IPC Network Use	**450**
New System Demand—Including new uses	6,077

Point-To-Point Transmission Rate		
a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	18.67

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)		
Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(3,145,545)

Network Transmission Revenue Requirements		
a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future - B2H without additional participation		
BPA Load Ratio Share	$	4,837,378
Long-Term PTP Revenue	$	8,700,743
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	93,175,690
Net change	**$**	**22,474,926**

Attachment 3 - Response Staff DR 16

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 1-4 with additional 3rd party subscription

	Project	Capital Cost	
	B2H 19% owned by IPCo (425/2300)	$	110,869,565
123.25%	B2H 19% owned by IPCo (425/2300)	$	136,646,739
	450 Market Purchase	included in B2H	

Annual Revenue Requirements

Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**136,646,739**
New Revenue Requirements for Project(s)	$	21,872,991
New Net Revenue Requirements	$	110,929,447

System Use (In MW)

Existing System Peak Demand	5,627
Future additional IPC Network Use	**425**
New System Demand—Including new uses	6,052

Point-To-Point Transmission Rate

a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	18.33

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)

Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(2,768,881)

Network Transmission Revenue Requirements

a) Existing			
BPA Load Ratio Share	$	4,237,114	
Long-Term PTP Revenue	$	7,375,757	
Legacy Contract Revenue	$	6,742,822	
Assigned to IPC Retail Load Service	$	70,700,764	
b) Future - B2H with additional participation			
BPA Load Ratio Share	$	4,763,797	
Long-Term PTP Revenue	$	8,542,082	
Legacy Contract Revenue	$	6,742,822	
Assigned to IPC Retail Load Service	$	90,880,746	
Net change	**$**	**20,179,982**	High Va

Attachment 3 - Response Staff DR 16

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 1-4 without additional 3rd party subscription

Project	Capital Cost
B2H 37% owned by IPCo (850/2300)	$ 221,739,130
450 Market Purchase	included in B2H

Annual Revenue Requirements

Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**221,739,130**
New Revenue Requirements for Project(s)	$	35,493,697
New Net Revenue Requirements	$	124,550,153

System Use (in MW)

Existing System Peak Demand	5,627
Future additional IPC Network Use	**425**
New System Demand—Including new uses	6,052

Point-To-Point Transmission Rate

a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	20.58

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)

Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(5,258,889)

Network Transmission Revenue Requirements

a) **Existing**		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) **Future - B2H without additional participation**		
BPA Load Ratio Share	$	5,254,035
Long-Term PTP Revenue	$	9,590,940
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	102,962,357
Net change	**$**	**32,261,593**

Attachment 3 - Response Staff DR 16

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 2-1

Project	Capital Cost	
Gateway 44% owned by IPCo (1020/2300)	$	1,316,021,739
250 East Side Purchase	included in GW	
670 MW Nuclear	included in GW	
300 MW Solar	$	7,500,000
104 MW Geothermal	$	30,000,000

Annual Revenue Requirements

Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**1,353,521,739**
New Revenue Requirements for Project(s)	$	216,657,702
New Net Revenue Requirements	$	305,714,159

System Use (in MW)

Existing System Peak Demand	5,627
Future additional IPC Network Use	**1,424**
New System Demand—Including new uses	7,051

Point-To-Point Transmission Rate

a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	43.36

Point-To-Point Revenue Adjustments (Incremental change to Existing Revenue Credits)

Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(30,458,820)

Network Transmission Revenue Requirements

a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future - New Projects without additional participation		
BPA Load Ratio Share	$	10,321,179
Long-Term PTP Revenue	$	20,205,817
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	268,444,341
Net change	**$**	**197,743,576**

Attachment 3 - Response Staff DR 16

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 2-2

Project	Capital Cost
Gateway 60% owned by IPCo (900/1500)	$ 1,780,500,000
MSTI 47% owned by IPCo (700/1500)	$ 466,666,667
700 MW East Side Purchase (Wyoming)	included in GW
200 MW Wind	Included in GW

Annual Revenue Requirements

Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**2,247,166,667**
New Revenue Requirements for Project(s)	$	359,703,101
New Net Revenue Requirements	$	448,759,557

System Use (in MW)

Existing System Peak Demand	5,627
Future additional IPC Network Use	**1,600**
New System Demand—Including new uses	7,227

Point-To-Point Transmission Rate

a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	62.10

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)

Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(51,188,896)

Network Transmission Revenue Requirements

a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future - New Projects without additional participation		
BPA Load Ratio Share	$	14,527,165
Long-Term PTP Revenue	$	28,937,873
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	398,551,697
Net change	**$**	**327,850,933**

Attachment 3 - Response Staff DR 16

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 2-3

Project		Capital Cost
Gateway 40% owned by IPCo (600/1500) (Aeolus-Hemingway)	$	1,187,000,000
300 MW Solar	$	7,500,000
400 Large Aero (simco Road)	$	32,000,000

Annual Revenue Requirements

Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**1,226,500,000**
New Revenue Requirements for Project(s)	$	196,325,382
New Net Revenue Requirements	$	285,381,838

System Use (in MW)

Existing System Peak Demand	5,627
Future additional IPC Network Use	**1,300**
New System Demand—Including new uses	6,927

Point-To-Point Transmission Rate

a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	41.20

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)

Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(28,070,146)

Network Transmission Revenue Requirements

a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future - New Projects without additional participation		
BPA Load Ratio Share	$	9,829,717
Long-Term PTP Revenue	$	19,199,644
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	249,609,655
Net change	**$**	**178,908,891**

Attachment 3 - Response Staff DR 16

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 2-4

Project	Capital Cost	
Gateway 31% owned by IPCo (600/1600)	$	675,000,000
500 Wind	Included in GW	
100 MW East Side Purchase	included in GW	
300 MW Aeros at Langley	$	22,000,000
1100 MW Aeros At Simco	$	102,000,000

Annual Revenue Requirements

Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**799,000,000**
New Revenue Requirements for Project(s)	$	127,895,622
New Net Revenue Requirements	$	216,952,078

System Use (in MW)

Existing System Peak Demand	5,627
Future additional IPC Network Use	**2,000**
New System Demand—Including new uses	7,627

Point-To-Point Transmission Rate

a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	28.45

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)

Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(13,960,338)

Network Transmission Revenue Requirements

a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future - New Projects without additional participation		
BPA Load Ratio Share	$	7,010,667
Long-Term PTP Revenue	$	13,256,220
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	189,942,369
Net change	**$**	**119,241,605**

Attachment 3 - Response Staff DR 16

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 2-5

Project	Capital Cost
Gateway 19% owned by IPCo (300/1600)	$ 337,500,000
300 Wind	Included in GW
1050 Existing Coal	

Annual Revenue Requirements		
Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**337,500,000**
New Revenue Requirements for Project(s)	$	54,023,495
New Net Revenue Requirements	$	143,079,951

System Use (in MW)		
Existing System Peak Demand		5,627
Future additional IPC Network Use		**300**
New System Demand—Including new uses		5,927

Point-To-Point Transmission Rate		
a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	24.14

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)		
Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(9,198,010)

Network Transmission Revenue Requirements		
a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future - New Projects without additional participation		
BPA Load Ratio Share	$	6,028,365
Long-Term PTP Revenue	$	11,250,202
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	119,058,562
Net change	**$**	**48,357,798**

Attachment 3 - Response Staff DR 16

IDAHO POWER COMPANY
RATE CALCULATION
12 Months Ended 12/31/2008

		Source	Amount	B2H				
				600,000,000				
	TRANSMISSION RATE BASE							
1	Transmission Plant (excluding Asset Retirement Costs)		742,870,924					
2	Generator Step Up Facilities		(16,703,791)					
3			(821,682)					
4	Account 252-Transmission (Net)		(2,310,431)					
5	General Plant (excluding Asset Retirement Costs)		30,744,244					
6	Intangible Plant		6,961,612					
7	Transmission Plant Held For Future Use		676,535					
8	General Plant Held For Future Use		112,758					
9	Transmission Depreciation Reserve (Acct 108) (excluding Asset Retirement Costs)		(230,292,212)					
10	Transmission Depreciation Reserve Generator Step-Ups		9,787,710					
11	Transmission Depreciation Reserve LGI's		93,681					
12	General Plant Depreciation Reserve (excluding Asset Retirement Costs)		(11,660,762)					
13	Amortization of Utility Plant		2,379,351					
14	ADIT Allocated to Trans		(49,151,423)					
15	ADIT Allocated to Gen & Intang		(2,555,053)					
16	Transmission Related Prepayments		1,252,469					
17	Transmission Materials & Supplies		10,342,021					
18	Transmission Cash Working Capital		4,644,612					
19	Unamortized RTO Development Costs		$2,384,070					
20	Transmission Rate Base	(20) + B2H	498,754,634	1,098,754,634				
21								
22	**RETURN AND ASSOCIATED INCOME TAXES**							
23	Overall Return		0.08203					
24	Composite Income Tax (Federal and State)		0.03427					
25	Return and Income Taxes	(20)*((23)+(24))	58,005,164	127,785,164				
26					Expense Allocation Ratio for new Transmission Plant			
27					100%	50%	0%	
28	**EXPENSES**							
29	Deprec Expense: Transmission		14,609,825		14,609,825			
30	Deprec Expense: General Plant		1,654,697			1,654,897		
31	Depreciation Expense: Intangible Plant		696,024			696,024		
32	Amort of ITC (Acct 411.4)		430,116			430,116		
33	O&M Expense: Transmission		23,196,223			23,196,223		
34	Less Account 561 (Load Dispatching)		(2,863,995)			(2,883,995)		
35	Less: Account 565 (Transmission of Electricity By Others)		(7,250,299)			(7,250,299)		
36	O&M Expense: A&G		13,960,670			13,980,670		
37	Taxes Other than Income:		3,003,630		3,003,830			
38	Amortization of RTO Development Costs		$922,866				$922,886	
39	Interest Expense (Network Upgrade Prepayments)		$221,728				$221,728	
40	Transmission Expense	Sum (29) Thru (39)	48,561,486	74,823,254	17,613,456	29,803,436	1,144,594	
41	Gross Transmission Revenue Requirement	(25) + (40))	106,566,650	202,608,418	31,839,445	41,839,216	1,144,594	
	Net Rev Req of New Project			96,041,768	recovery from all Network Transmission Customers			
			0.14	0.16	ratio of net revenue requirement to new capital investment			
43	Transmission Revenue Credits	Schedule 4	(17,510,193)	(17,510,193)				
44								
45	Net PTP Transmission Revenue Requirement	(41) - (43)	89,056,456	185,098,225				
46								
47	System Peak Demand - MW	Schedule 5	5,627	5,627	assumes no additional service			
48								
49	Annual Rate $/kW per year	(45)/((47)*1000)	15.83	32.90	new transmission rate with no additional service			
	New Service			3,000	assume new transmission service - fully subscribed project			
				8,627	new system peak demand			
	Annual Rate $/kW per year			21.46	new transmission rate with project fully subscribed			
	Revenue from new service			64,370,174				
	New Net Rev Req of New Project - if fully subscribed			31,671,594	recovery from all Network Transmission Customers			

Attachment 3 - Response Staff DR 16

IDAHO POWER COMPANY
RATE CALCULATION
12 Months Ended 12/31/2008

	TRANSMISSION RATE BASE
1	Transmission Plant (excluding Asset Retirement Costs)
2	Generator Step Up Facilities
3	
4	Account 252-Transmission (Net)
5	General Plant (excluding Asset Retirement Costs)
6	Intangible Plant
7	Transmission Plant Held For Future Use
8	General Plant Held For Future Use
9	Transmission Depreciation Reserve (Acct 108) (excluding Asset Retirement Costs)
10	Transmission Depreciation Reserve Generator Step-Ups
11	Transmission Depreciation Reserve LGI's
12	General Plant Depreciation Reserve (excluding Asset Retirement Costs)
13	Amortization of Utility Plant
14	ADIT Allocated to Trans
15	ADIT Allocated to Gen & Intang
16	Transmission Related Prepayments
17	Transmission Materials & Supplies
18	Transmission Cash Working Capital
19	Unamortized RTO Development Costs
20	Transmission Rate Base
21	
22	**RETURN AND ASSOCIATED INCOME TAXES**
23	Overall Return
24	Composite Income Tax (Federal and State)
25	Return and Income Taxes
26	
27	
28	**EXPENSES**
29	Deprec Expense: Transmission
30	Deprec Expense: General Plant
31	Depreciation Expense: Intangible Plant
32	Amort of ITC (Acct 411.4)
33	O&M Expense: Transmission
34	Less Account 561 (Load Dispatching)
35	Less: Account 565 (Transmission of Electricity By Others)
36	O&M Expense: A&G
37	Taxes Other than Income:
38	Amortization of RTO Development Costs
39	Interest Expense (Network Upgrade Prepayments)
40	Transmission Expense
41	Gross Transmission Revenue Requirement
42	
43	Transmission Revenue Credits
44	
45	Net PTP Transmission Revenue Requirement
46	
47	**System Peak Demand - MW**
48	

Attachment 3 - Response Staff DR 16

49	Annual Rate $/kW per year
50	Monthly Rate $/kW per month
51	Weekly Rate $/kW per week
52	Daily Rate $/kW per day (Mon-Sat)
53	Daily Rate $/kW per day (Sunday)
54	Hourly Rate $/MW per hour (Peak)
55	Hourly Rate $/MW per hour (Off-Peak)

Attachment 3 - Response Staff DR 16

Source	Amount
FF1 p207 58(g) - 57(g)	742,870,924
Schedule 7	(16,703,791)
	(821,682)
Schedule 9	(2,310,431)
Schedule 1	30,744,244
Schedule 1	6,961,612
FF1 p214 4d + 5d + 12d	676,535
Schedule 1	112,758
FF1 p 219 25(b) - 108.100 = 0	(230,292,212)
Schedule 7	9,787,710
Schedule 8	93,681
Schedule 1	(11,660,762)
Schedule 1	2,379,351
Schedule 1	(49,151,423)
Schedule 1	(2,555,053)
Schedule 1	1,252,469
Schedule 1	10,342,021
Schedule 1	4,644,612
OATT Attach H, 3.1.1.11(c)	$2,384,070
Sum (1) Thru (19)	498,754,634
Schedule 6	0.08203
Schedule 6	0.03427
(20)*((23)+(24))	58,005,164
Schedule 2	14,609,825
Schedule 2	1,654,697
Schedule 2	696,024
Schedule 2	430,116
Schedule 2	23,196,223
FF1 p 321 84b to 92b	(2,883,995)
FF1 p 321 96b	(7,250,299)
Schedule 2	13,960,670
Schedule 2	3,003,630
OATT Attach H, 3.7	$922,866
Schedule 9	$221,728
Sum (29) Thru (39)	48,561,486
(25) + (40))	106,566,650
Schedule 4	(17,510,193)
(41) - (43)	89,056,456
Schedule 5	5,627

Attachment 3 - Response Staff DR 16

(45)/((47)*1000)	15.83
(49) / 12	1.3192
(49) / 52	0.3044
(51) / 6	0.0507
(51) / 7	0.0435
(49)*1000 / 4896	3.23
(49)*1000 / 8760	1.81

Attachment 3 - Response Staff DR 16

IDAHO POWER COMPANY
Transmission Cost of Service Rate Development
12 Months Ended 12/31/2008

SCHEDULE 5
Allocation Demand and Capability Data
2008

	A	B	C	D	E	F	G
	Firm Network Service for Self	Firm Network Service for Others	Long-Term Firm PTP Reservations	TOTAL	Legacy Agreements 2/	CBM	TOTAL
	(D) - (B) -(C)			Form 1p400(b) 1/			
January	2443	241	677	3361	2014	330	5705
February	2252	204	677	3133	2014	330	5477
March	2004	179	677	2860	2014	330	5204
April	1864	183	696	2743	2014	330	5087
May	2334	284	696	3314	2014	330	5658
June	3200	344	696	4240	2014	330	6584
July	3116	349	696	4161	2014	330	6505
August	2978	293	696	3967	2014	330	6311
September	1709	199	696	2604	2014	330	4948
October	1981	189	696	2866	2014	330	5210
November	1901	243	696	2840	2014	330	5184
December	2293	313	696	3302	2014	330	5646
12 CP (Rounded)	2339	252	691	3283	2014	330	5627

1/ Does not include Short Term Firm PTP Reservations reported on Column (i), page 400 of the Form 1.
2/ RTSA = 1,514 MW; ITSA = 250 MW; TFA = 250 MW

	Firm Network Service For Others					
	Imnaha	USBR	Raft River	BPA - PF	BPA-OTECC	Total Form 1
January	0.48209	1	13	144	83	241
February	0.34944	1	11	126	66	204
March	0.33614	0	11	107	61	179
April	0.30583	9	11	100	63	183
May	0.18809	57	60	118	49	284
June	0.27706	72	66	144	62	344
July	0.32431	73	69	144	63	349
August	0.29120	51	54	129	59	293
September	0.19845	31	40	86	42	199
October	0.17871	30	29	89	41	189
November	0.32844	59	12	113	59	243
December	0.50820	82	12	136	82	313
12 CP (Rounded)	0	39	32	120	61	252

	Long-Term Firm Transmission - OASIS Reservations										
	IPCM	IPCM	IPCM	IPCM	IPCM	IPCM	IPCM	IPCM	SCL	PAC	TOTAL
OASIS Ref:	70237874 (79606)	96618	70241483 (144434)	70752544 (143190)	70388764 (70361498) & 70665456	71153438 (70416899) &(144968)	70237836 & 70592430	71195969	71331211	70287097	
contract term	4/1/01-12/31/2010	7/1/01-12/31/09	4/1/04-04/01/2010	7/1/04-6/30/2010	5/1/05-5/1/06 & 5/1/06-5/1/2011	3/1/2007-12/31/2010 (9/1/05-3/1/07)	6/1/06-6/1/2010	4/1/2007-4/1/2008	1/1/2008-1/1/2009	4/1/2008-4/1/2009	
POR/POD	IPCO/LGBP	IPCO/M345	IPCO/LGBP	JEFF/IPCO	IPCO/LOLO	BOBR/IPCO	IPCO/MLCK	BOBR/JEFF	LYPK/LGBP	KPRT/BOBR	
January	171	25	75	87	75	75	30	42	97	0	677
February	171	25	75	87	75	75	30	42	97	0	677
March	171	25	75	87	75	75	30	42	97	0	677
April	171	25	75	87	75	75	30	0	97	61	696
May	171	25	75	87	75	75	30	0	97	61	696
June	171	25	75	87	75	75	30	0	97	61	696
July	171	25	75	87	75	75	30	0	97	61	696
August	171	25	75	87	75	75	30	0	97	61	696
September	171	25	75	87	75	75	30	0	97	61	696
October	171	25	75	87	75	75	30	0	97	61	696
November	171	25	75	87	75	75	30	0	97	61	696
December	171	25	75	87	75	75	30	0	97	61	696
12 CP (Rounded)	171	25	75	87	75	75	30	11	97	46	691

Attachment 3 - Response Staff DR 16

IDAHO POWER COMPANY
Transmission Cost of Service Rate Development
12 Months Ended 12/31/2008

SCHEDULE 4 WORKPAPER, PAGE 1
Account 454 Rents From Electric Property by Category and Subaccount
2008

Subaccount and Category (Source of Rent) A	Total Amount B	Treatment: Amount Revenue Credited C	Nature of Each Source of Rent Comments D
454101, 454102			
		$0	Distribution-related facilites charges
Real Estate Rents	330,651	$48,669	See Schedule 4 Workpaper, page 2
Joint Pole Rents	1,505,132	$254,803	See Schedule 4 Workpaper, page 3
Cogeneration	546,786	$42,534	See Schedule 4 Workpaper, page 4
General Business Facilities Charges	6,561,032	$0	Distribution-related facilites charges under Sch 66-(optional distribution services) such as devices for off-site meter reading; Schedules 9, 19, St. Ltg., Dusk to Dawn, etc
Subtotal	$8,943,600	$346,006	To Schedule 4, lines 4, 5 and 6
454001, 454003, 454004, 454702			
Overnight Park Rents	327,242	$0	Power Supply-related. These fees are for the usage of recreational parks located at hydroelectric power plants owned by the Company
Subtotal	$327,242	$0	
454181, 454281			
Fiber Rents	447,361	$0	Fiber Rents - Non-transmission as per settlement
Subtotal	$447,361	$0	
454251, 454271			
Restated Transmission Services Agreement Between IPC and Pacificorp dated February 6, 1992	6,650,862	$0	Legacy Agreement-Transmission facilites charges
Transmission Facilities Agreement between IPC, PP&L and UP&L, dated June 1, 1974	2,055,220	$0	Legacy Agreement-Transmission facilites charges
Agreement for Interconnection and Transmission Services between IPC and UP&L dated March 19, 1982	377,345	$0	Legacy Agreement-Transmission facilites charges
Transmission Services Agreement between IPC and the City of Seattle dated June 27, 1988.	-	$0	Legacy Agreement-Transmission facilites charges - Contract expired
Section 3 of the Microwave Cooperative Use Agreement dated August 2, 1974, between PacifiCorp and Idaho Power Company	15,395	$0	Communication service
Section 3.1 of the Communications Agreement between Idaho Power Company and PacifiCorp dated February 20, 1996	$55,284	$0	Communication service
Subtotal	9,154,106	$0	
TOTAL ACCOUNT 454	$18,872,309	$346,006	Source = the Form 1, page 300
TOTAL AMOUNT REVENUE CREDITED		$346,006	To Schedule 4

	1-4	1-2	2-4	2-4 Wind & Peakers	1-4 + 2-4 Base Case	1-2 + 2-4 (1-2 no B2H)
Idaho Powe	1-4 Boardman to Hem	1-2 Gas Peaker	2-4 Wind & Peakers	1-2 no B2H	1-4 Boardman to Hemin	1-2 Gas Peaker
0%	2.0199	2.2814	2.59989	2.61589695	$4.6198125718	$4.8972495098
5%	2.0462	2.2814	2.59989	2.6158970	$4.6460625718	$4.8972495098
10%	2.0724	2.2814	2.59989	2.6158970	$4.6723125718	$4.8972495098
15%	2.0987	2.2814	2.59989	2.6158970	$4.6985625718	$4.8972495098
20%	2.1249	2.2814	2.59989	2.6158970	$4.7248125718	$4.8972495098
25%	2.1512	2.2814	2.59989	2.6158970	$4.7510625718	$4.8972495098
30%	2.1774	2.2814	2.59989	2.6158970	$4.7773125718	$4.8972495098
35%	2.2037	2.2814	2.59989	2.6158970	$4.8035625718	$4.8972495098
40%	2.2299	2.2814	2.59989	2.6158970	$4.8298125718	$4.8972495098
45%	2.2562	2.2814	2.59989	2.6158970	$4.8560625718	$4.8972495098
50%	2.2824	2.2814	2.59989	2.6158970	$4.8823125718	$4.8972495098
55%	2.3087	2.2814	2.59989	2.6158970	$4.9085625718	$4.8972495098
60%	2.3349	2.2814	2.59989	2.6158970	$4.9348125718	$4.8972495098
65%	2.3612	2.2814	2.59989	2.6158970	$4.9610625718	$4.8972495098
70%	2.3874	2.2814	2.59989	2.6158970	$4.9873125718	$4.8972495098
75%	2.4137	2.2814	2.59989	2.6158970	$5.0135625718	$4.8972495098
80%	2.4399	2.2814	2.59989	2.6158970	$5.0398125718	$4.8972495098
85%	2.4662	2.2814	2.59989	2.6158970	$5.0660625718	$4.8972495098
90%	2.4924	2.2814	2.59989	2.6158970	$5.0923125718	$4.8972495098
95%	2.5187	2.2814	2.59989	2.6158970	$5.1185625718	$4.8972495098
100%	2.5449	2.2814	2.59989	2.6158970	$5.1448125718	$4.8972495098

Source: 2009 IRP Appendix C Page 16. 1-4 B2H Expected Portfolio Cost.

Source: 2009 IRP Appendix C Page 16. 1-2 Gas (Peaker) Expected Portfolio Cost.

Source: 2009 IRP Appendix C Page 20. 2-4 Wind & Peakers Expected Portfolio Cost.

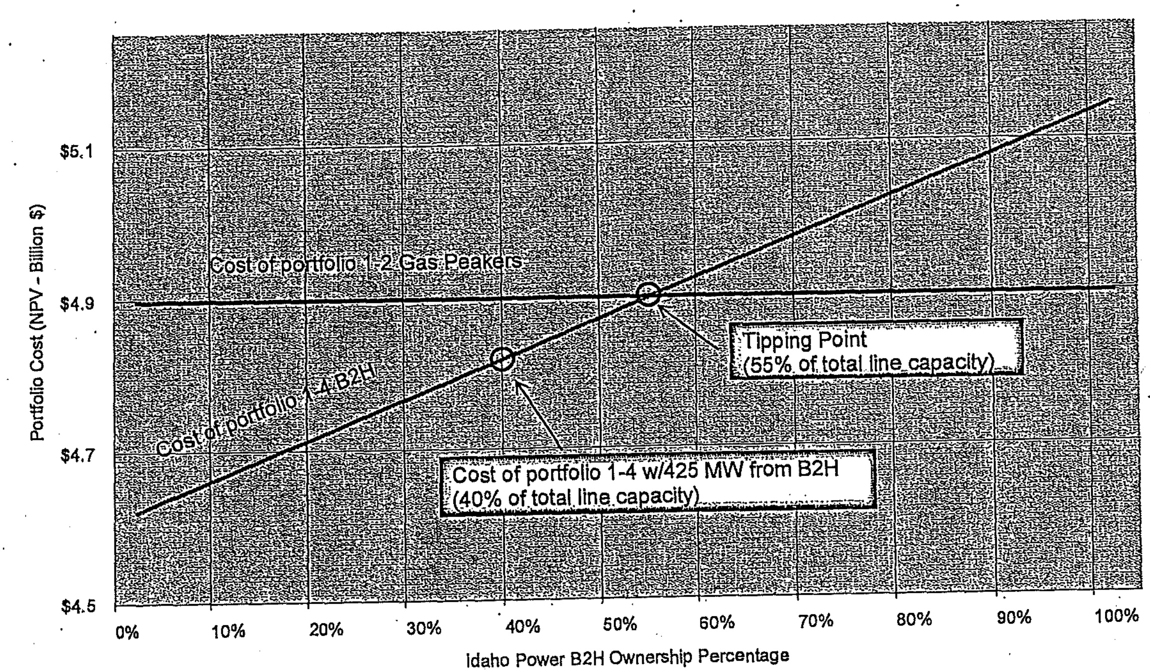
Source: Original Aurora run for tipping chart. All previous 11-20 year runs had B2H. Removed B2H from NTTG long term plan in Aurora and re-ran 2-4 with 1-2 starting point.

	$	210.00	Million 40% B2H NPV
	$	525.00	
0.5250	$	525.00	check
	$	210.00	check
0.2100			

Line Slope
0.0263

40% of transmission capacity Idaho Power Subscription B2H

	Portfolio 1-4 (425 MW) Fully Subscribed	Outbound not sold Fully Subscribed			NPV Outbound Sold	NPV outbound Not Sold
2010	0	0	0	0		
2011	0	0	0	0		
2012	0	0	0	0		
2013	0	0	0	0		
2014	0	0	0	0		
2015	$ 16,520,081	$ 32,261,593	0	0		
2016	$ 16,520,081	$ 32,261,593	0	0		
2017	$ 16,520,081	$ 32,261,593	0	0		
2018	$ 16,520,081	$ 32,261,593	0	0		
2019	$ 16,520,081	$ 32,261,593	0	0	$48,365,600	$94,451,794
2020	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2021	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2022	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2023	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2024	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2025	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2026	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2027	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2028	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2029	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593	$59,148,872.33	$115,510,138.56
	$107,514,472.11	$209,961,933.05			$107,514,472.11	$209,961,933.05



Attachment 4 - Response Staff DR 16

Idaho Power Own	1-4 IRP	1-4 Hi B2H$	1-4 Hi gas Hi B2H$	1-4 Hi gas	1-4 Low gas	1-2 Exp Gas	1-2 Hi Gas	1-2 Low Gas
	1-4 Boardman to Hemingway					1-2 Gas Peaker		
0%	2.0199	2.0199	1.9822	1.9822	2.1959	2.2814	2.23770	2.25445
5%	2.0462	2.0552	2.0174	2.0084	2.2221	2.2814	2.23770	2.25445
10%	2.0724	2.0904	2.0527	2.0347	2.2484	2.2814	2.23770	2.25445
15%	2.0987	2.1257	2.0879	2.0609	2.2746	2.2814	2.23770	2.25445
20%	2.1249	2.1609	2.1232	2.0872	2.3009	2.2814	2.23770	2.25445
25%	2.1512	2.1962	2.1584	2.1134	2.3271	2.2814	2.23770	2.25445
30%	2.1774	2.2314	2.1937	2.1397	2.3534	2.2814	2.23770	2.25445
35%	2.2037	2.2667	2.2289	2.1659	2.3796	2.2814	2.23770	2.25445
40%	***2.2299***	***2.3019***	***2.2642***	***2.1922***	***2.4059***	2.2814	2.23770	2.25445
45%	2.2562	2.3372	2.2994	2.2184	2.4321	2.2814	2.23770	2.25445
50%	2.2824	2.3724	2.3347	2.2447	2.4584	2.2814	2.23770	2.25445
55%	2.3087	2.4077	2.3699	2.2709	2.4846	2.2814	2.23770	2.25445
60%	2.3349	2.4429	2.4052	2.2972	2.5109	2.2814	2.23770	2.25445
65%	2.3612	2.4782	2.4404	2.3234	2.5371	2.2814	2.23770	2.25445
70%	2.3874	2.5134	2.4757	2.3497	2.5634	2.2814	2.23770	2.25445
75%	2.4137	2.5487	2.5109	2.3759	2.5896	2.2814	2.23770	2.25445
80%	2.4399	2.5839	2.5462	2.4022	2.6159	2.2814	2.23770	2.25445
85%	2.4662	2.6192	2.5814	2.4284	2.6421	2.2814	2.23770	2.25445
90%	2.4924	2.6544	2.6167	2.4547	2.6684	2.2814	2.23770	2.25445
95%	2.5187	2.6897	2.6519	2.4809	2.6946	2.2814	2.23770	2.25445
100%	2.5449	2.7249	2.6872	2.5072	2.7209	2.2814	2.23770	2.25445

Idaho Power Own	2-4 exp gas	2-4 Hi gas	2-4 Low gas	2-4 Exp gas	2-4 Hi Gas	2-4 Low Gas	1-4 + 2-4 Base Case	1-2 + 2-4 (1-2 no B2H$)
	2-4 Wind & Peakers			1-2 no B2H			1-4 Boardman to Hemingway	1-2 Gas Peaker
0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	4.6198	4.8984
5%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	4.6461	4.8984
10%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	4.6723	4.8984
15%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	4.6986	4.8984
20%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	4.7248	4.8984
25%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	4.7511	4.8984
30%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	4.7773	4.8984
35%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	4.8036	4.8984
40%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	4.8298	4.8984
45%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	4.8561	4.8984
50%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	4.8823	4.8984
55%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	4.9086	4.8984
60%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	4.9348	4.8984
65%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	4.9611	4.8984
70%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	4.9873	4.8984
75%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	5.0136	4.8984
80%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	5.0398	4.8984
85%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	5.0661	4.8984
90%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	5.0923	4.8984
95%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	5.1186	4.8984
100%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022	5.1448	4.8984

?

Idaho Power Own	1-4 high B2H$ + 2-4 Low gas	1-2 Low gas + 2-4 Low Gas no B2H$	1-4 exp B2H$ High gas + 2-4 High gas	1-2 High gas + 2-4 High gas no B2H$	1-4 exp T Low gas + 2-4 Low Gas	1-2 Low gas + 2-4 Low gas no B2H$
0%	4.33889	4.76467	4.75772	4.93559	4.51486	4.76467
5%	4.37414	4.76467	4.79297	4.93559	4.54111	4.76467
10%	4.40939	4.76467	4.82822	4.93559	4.56736	4.76467
15%	4.44464	4.76467	4.86347	4.93559	4.59361	4.76467
20%	4.47989	4.76467	4.89872	4.93559	4.61986	4.76467
25%	4.51514	4.76467	4.93397	4.93559	4.64611	4.76467
30%	4.55039	4.76467	4.96922	4.93559	4.67236	4.76467
35%	4.58564	4.76467	5.00447	4.93559	4.69861	4.76467
40%	4.62089	4.76467	5.03972	4.93559	4.72486	4.76467
45%	4.65614	4.76467	5.07497	4.93559	4.75111	4.76467
50%	4.69139	4.76467	5.11022	4.93559	4.77736	4.76467
55%	4.72664	4.76467	5.14547	4.93559	4.80361	4.76467
60%	4.76189	4.76467	5.18072	4.93559	4.82986	4.76467
65%	4.79714	4.76467	5.21597	4.93559	4.85611	4.76467
70%	4.83239	4.76467	5.25122	4.93559	4.88238	4.76467
75%	4.86764	4.76467	5.28647	4.93559	4.90861	4.76467
80%	4.90289	4.76467	5.32172	4.93559	4.93486	4.76467
85%	4.93814	4.76467	5.35697	4.93559	4.96111	4.76467
90%	4.97339	4.76467	5.39222	4.93559	4.98736	4.76467
95%	5.00864	4.76467	5.42747	4.93559	5.01361	4.76467
100%	5.04389	4.76467	5.46272	4.93559	5.03986	4.76467

Source: 2009 IRP Appendix C Page 16. 1-4 B2H Expected Portfolio Cost.

Source: 2009 IRP Appendix C Page 16. 1-2 Gas (Peaker)

Source: 2009 IRP Appendix C Page 20. 2-4 Wind & Peakers

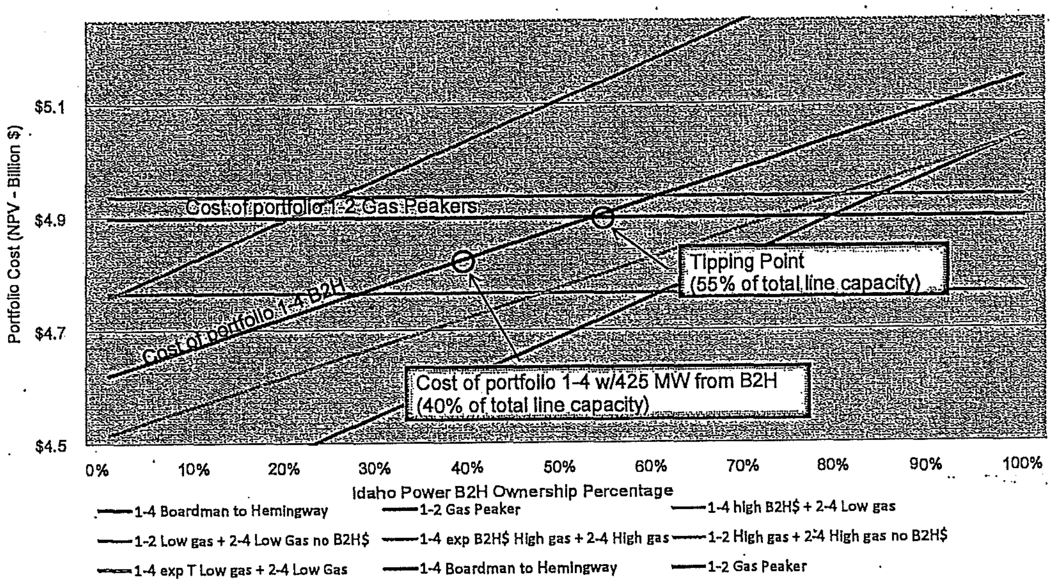
Source: Original Aurora run for tipping chart. All previous 11-20 year runs had B2H. Removed B2H from NTTG long term plan

	$ 210.00	$ 282.00	Million 40% B2H NPV
	$ 525.00	$ 705.00	
0.5250	$ 525.00	$ 705.00	check
	$ 210.00	$ 282.00	check
0.2100			
	Line Slope		
	0.0263	0.0353	

40% of transmission capacity Idaho Power Subscription B2H

	Portfolio 1-4 (425 M Fully Subscribed	Outbound not so Fully Subscribed	Portfolio 1-4 (425 MW) Fully Subscribed	Outbound not sold Fully Subscribed
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	0	0	0	0
2015	$ 16,520,081	$ 32,261,593	$ 21,667,625	$ 43,335,250
2016	$ 16,520,081	$ 32,261,593	$ 21,667,625	$ 43,335,250
2017	$ 16,520,081	$ 32,261,593	$ 21,667,625	$ 43,335,250
2018	$ 16,520,081	$ 32,261,593	$ 21,667,625	$ 43,335,250
2019	$ 16,520,081	$ 32,261,593	$ 21,667,625	$ 43,335,250
2020	$ 16,520,081	$ 32,261,593	$ 21,667,625	$ 43,335,250
2021	$ 16,520,081	$ 32,261,593	$ 21,667,625	$ 43,335,250
2022	$ 18,520,081	$ 32,261,593	$ 21,667,625	$ 43,335,250
2023	$ 16,520,081	$ 32,261,593	$ 21,667,625	$ 43,335,250
2024	$ 16,520,081	$ 32,261,593	$ 21,667,625	$ 43,335,250
2025	$ 16,520,081	$ 32,261,593	$ 21,667,625	$ 43,335,250
2026	$ 16,520,081	$ 32,261,593	$ 21,667,625	$ 43,335,250
2027	$ 16,520,081	$ 32,261,593	$ 21,667,625	$ 43,335,250
2028	$ 16,520,081	$ 32,261,593	$ 21,667,625	$ 43,335,250
2029	$ 16,520,081	$ 32,261,593	$ 21,667,625	$ 43,335,250
	$107,514,472	$209,961,933	$141,015,246	$282,030,492

OPUC LC-50 DR 16 Tipping Point Chart



Attachment 4 - Response Staff DR 16

Total	Average	2019	17536040	$277,407.80	1_1_Solar_co	151,117.35
Resource	Average	2010	17159560	$261,559.30	1_2__FrPeake	261,559.30
Market	Average	2010	1128667	$53,579.92	1_2__FrPeake	53,579.92
Market	Average	2010	-2544337	($97,316.15)	1_2__FrPeake	(97,316.15)
Total	Average	2010	15743890	$217,823.00	1_2__FrPeake	217,823.00
Resource	Average	2011	18038060	$295,494.20	1_2__FrPeake	276,208.71
Market	Average	2011	1050100	$58,780.12	1_2__FrPeake	54,943.82
Market	Average	2011	-2718065	($122,566.50)	1_2__FrPeake	(114,567.17)
Total	Average	2011	16370090	$231,707.80	1_2__FrPeake	216,585.34
Resource	Average	2012	18290560	$328,161.00	1_2__FrPeake	286,723.83
Market	Average	2012	772394.4	$45,931.30	1_2__FrPeake	40,131.51
Market	Average	2012	-2314695	($113,407.90)	1_2__FrPeake	(99,087.79)
Total	Average	2012	16748260	$260,684.40	1_2__FrPeake	227,767.55
Resource	Average	2013	18495790	$339,375.50	1_2__FrPeake	277,169.67
Market	Average	2013	852710	$54,407.82	1_2__FrPeake	44,435.14
Market	Average	2013	-2475884	($129,301.40)	1_2__FrPeake	(105,601.10)
Total	Average	2013	16872620	$264,481.90	1_2__FrPeake	216,003.70
Resource	Average	2014	18569900	$356,520.00	1_2__FrPeake	272,168.29
Market	Average	2014	858983.3	$57,454.79	1_2__FrPeake	43,861.14
Market	Average	2014	-2374586	($128,891.90)	1_2__FrPeake	(98,396.41)
Total	Average	2014	17054290	$285,082.90	1_2__FrPeake	217,633.03
Resource	Average	2015	18503020	$360,076.50	1_2__FrPeake	256,943.02
Market	Average	2015	1028096	$69,637.57	1_2__FrPeake	49,691.91
Market	Average	2015	-2382082	($130,833.40)	1_2__FrPeake	(93,359.96)
Total	Average	2015	17149040	$298,880.60	1_2__FrPeake	213,274.91
Resource	Average	2016	19198870	$375,120.00	1_2__FrPeake	250,207.70
Market	Average	2016	815253.7	$57,476.00	1_2__FrPeake	38,336.90
Market	Average	2016	-2737902	($155,396.80)	1_2__FrPeake	(103,650.77)
Total	Average	2016	17276220	$277,199.20	1_2__FrPeake	184,893.83
Resource	Average	2017	19044810	$380,628.00	1_2__FrPeake	237,311.94
Market	Average	2017	837436.4	$60,801.53	1_2__FrPeake	37,908.22
Market	Average	2017	-2541880	($151,676.50)	1_2__FrPeake	(94,566.47)
Total	Average	2017	17340360	$289,753.00	1_2__FrPeake	180,653.67
Resource	Average	2018	19060130	$391,090.60	1_2__FrPeake	227,921.16
Market	Average	2018	837256.8	$63,171.17	1_2__FrPeake	36,815.12
Market	Average	2018	-2456986	($151,863.90)	1_2__FrPeake	(88,503.78)
Total	Average	2018	17440400	$302,397.90	1_2__FrPeake	176,232.51
Resource	Average	2019	18883990	$394,599.20	1_2__FrPeake	214,957.14
Market	Average	2019	1013860	$77,438.66	1_2__FrPeake	42,184.56
Market	Average	2019	-2361809	($150,986.70)	1_2__FrPeake	(82,249.71)
Total	Average	2019	17536040	$321,051.10	1_2__FrPeake	174,891.96

April 21, 2010

Subject: Docket No. LC 50
Idaho Power Company's **SUPPLEMENTAL** Response to Staff's Data Request 16

STAFF'S DATA REQUEST NO. 16:

The original Data Request No. 16 was stated as follows:

> ***Please conduct a construction cost risk analysis for the Boardman to Hemingway transmission line. This analysis should include a "tipping point" calculation with regard to portfolio 1-2. At a minimum, this risk analysis should include the following scenarios: worst case construction costs in portfolio 1-4 vs. low natural gas prices in portfolio 1-2, best case construction costs in 1-4 vs. high natural gas prices in 1-2, and best case construction costs in 1-4 vs. low natural gas prices in 1-2. Please provide your analysis in an Excel workbook with all formula's intact and references cited.***

During a follow-up phone conversation with OPUC Staff on April 7, 2010, the following additional information was requested:

1. Update the B2H construction cost estimate to include more typical values for AFUDC, include substation costs, evaluate a high transmission cost scenario, and provide an updated the tipping point chart.

2. Provide a description of benefits of the B2H transmission line that could not be captured in the IRP analysis using the AURORA model.

IDAHO POWER COMPANY'S *SUPPLEMENTAL* RESPONSE TO STAFF'S DATA REQUEST NO. 16:

An updated tipping point chart showing additional scenarios is attached as well as the data used to create the chart.

While the AURORA model simulates the total cost of any particular portfolio of resources, there are intangible benefits of having additional transmission capacity available that the AURORA model is not able to capture and/or quantify. In addition, these benefits would help many utilities, independent power producers, and, ultimately, customers throughout the region, not just Idaho

Power Company ("Idaho Power" or "Company"). Idaho Power sees these benefits as falling into three categories: (1) the flexibility to access multiple resources, (2) the integration of renewable resources, and (3) greater reliability/availability.

When compared to a supply-side resource, additional transmission capacity provides more flexibility and greater optionality. Idaho Power's primary market interaction is with other participants at the Mid-C market hub. The Mid-C market has historically been a very liquid market due to the large number of participants, and the large amount of hydroelectric generation in the region has typically kept market prices lower than other markets. In addition, Idaho Power experiences peak loads during the summer months when most other Pacific Northwest utilities peak in the winter. This seasonal differential allows Idaho Power to benefit from additional generation capacity in the Northwest during the summer months, while winter peaking utilities benefit during the winter months.

The ability to purchase electricity from multiple sources in the market inherently contains less risk than building a single resource. A natural gas resource will be subject to gas price risk and volatility, and renewable resources have increased risk due to integration issues. In comparison, a market purchase is a firm source of supply that can be purchased short-term or long-term. Market prices will be subject to the previously mentioned risk factors, but the diversity of resources selling into the market will mitigate the level of risk.

Increased transmission capacity to the Pacific Northwest would also give Idaho Power the option of siting resources to the northwest of its service area. This option is not currently available because of existing transmission constraints. While the Boardman to Hemingway ("B2H") transmission line appears to be the best option for serving near-term needs, in the future Idaho Power would expect to add additional supply-side resources as part of maintaining a balanced portfolio and the ability to consider Pacific Northwest resources would benefit Idaho Power's customers. In addition, increased transmission capacity would allow Idaho Power to consider joint resource development with other utilities in the Pacific Northwest.

The construction of the B2H transmission line will be important for the integration of renewable resources. Without an increase in the available transmission capacity between Idaho and the Pacific Northwest, the development of innovative, market-based solutions for integrating renewable resources within the region will not happen as quickly or effectively as it would in a deeper market, with more participants, across a more diverse geographic region. If transmission constraints prevent parties from participating in intra-hour energy and capacity transactions as postulated, the whole region will suffer. However, if there is sufficient transmission capacity available and innovative market-based solutions become a reality, then the region will be well-positioned to support a larger penetration level of renewable resources. The entire region would benefit from the associated economic development that would take place with the construction of additional renewable resources.

Regarding reliability, the transmission path will achieve a rating which accounts for system outages and provides for a reliable and "safe" operating condition. The path will be scheduled to the rating limit at times during the year. However, it is likely that the path will be well below this limit during many hours of the year. One could conclude that the system will be substantially more reliable with the addition of B2H during the operating conditions of reduced path utilization (periods other than Idaho Power's summer peak). In addition, transmission lines have a greater availability than generation facilities. A 500 kV transmission line will typically experience 19.4 forced outage-hours per year (source: *NERC 2008 Transmission Availability Data System Report*). Note that NERC only tracks automatic outages which cause the circuit to change from an in-service to out-of-service condition unrelated to a scheduled maintenance outage. A combined-cycle natural gas facility will have an equivalent forced outage rate demand ("EFORd") of 534 hours per year (source: *NERC 2004-2008 Generating Unit Statistical Brochure-Generator Availability Data System*). Generation facilities also typically require substantially more scheduled maintenance hours than transmission lines, which further demonstrates that a transmission line will have greater availability and thus provide greater system reliability.

Attachment - Supplemental Response Staff DR 16

	1-4	1-2	2-4	2-4 Wind & Peakers	1-4 + 2-4 Base Case	1-2 + 2-4 (1-2 no B2H)
Idaho Powe	1-4 Boardman to Hem	1-2 Gas Peaker	2-4 Wind & Peakers	1-2 no B2H	1-4 Boardman to Hemin	1-2 Gas Peaker
0%	2.0199	2.2814	2.59989	2.61589695	$4.6198125718	$4.8972495098
5%	2.0462	2.2814	2.59989	2.6158970	$4.6460625718	$4.8972495098
10%	2.0724	2.2814	2.59989	2.6158970	$4.6723125718	$4.8972495098
15%	2.0987	2.2814	2.59989	2.6158970	$4.6985625718	$4.8972495098
20%	2.1249	2.2814	2.59989	2.6158970	$4.7248125718	$4.8972495098
25%	2.1512	2.2814	2.59989	2.6158970	$4.7510625718	$4.8972495098
30%	2.1774	2.2814	2.59989	2.6158970	$4.7773125718	$4.8972495098
35%	2.2037	2.2814	2.59989	2.6158970	$4.8035625718	$4.8972495098
40%	2.2299	2.2814	2.59989	2.6158970	$4.8298125718	$4.8972495098
45%	2.2562	2.2814	2.59989	2.6158970	$4.8560625718	$4.8972495098
50%	2.2824	2.2814	2.59989	2.6158970	$4.8823125718	$4.8972495098
55%	2.3087	2.2814	2.59989	2.6158970	$4.9085625718	$4.8972495098
60%	2.3349	2.2814	2.59989	2.6158970	$4.9348125718	$4.8972495098
65%	2.3612	2.2814	2.59989	2.6158970	$4.9610625718	$4.8972495098
70%	2.3874	2.2814	2.59989	2.6158970	$4.9873125718	$4.8972495098
75%	2.4137	2.2814	2.59989	2.6158970	$5.0135625718	$4.8972495098
80%	2.4399	2.2814	2.59989	2.6158970	$5.0398125718	$4.8972495098
85%	2.4662	2.2814	2.59989	2.6158970	$5.0660625718	$4.8972495098
90%	2.4924	2.2814	2.59989	2.6158970	$5.0923125718	$4.8972495098
95%	2.5187	2.2814	2.59989	2.6158970	$5.1185625718	$4.8972495098
100%	2.5449	2.2814	2.59989	2.6158970	$5.1448125718	$4.8972495098

Source: 2009 IRP Appendix C Page 16. 1-4 B2H Expected Portfolio Cost.

Source: 2009 IRP Appendix C Page 16. 1-2 Gas (Peaker) Expected Portfolio Cost.

Source: 2009 IRP Appendix C Page 20. 2-4 Wind & Peakers Expected Portfolio Cost.

Source: Original Aurora run for tipping chart. All previous 11-20 year runs had B2H. Removed B2H from NTTG long term plan in Aurora and re-ran 2-4 with 1-2 starting point.

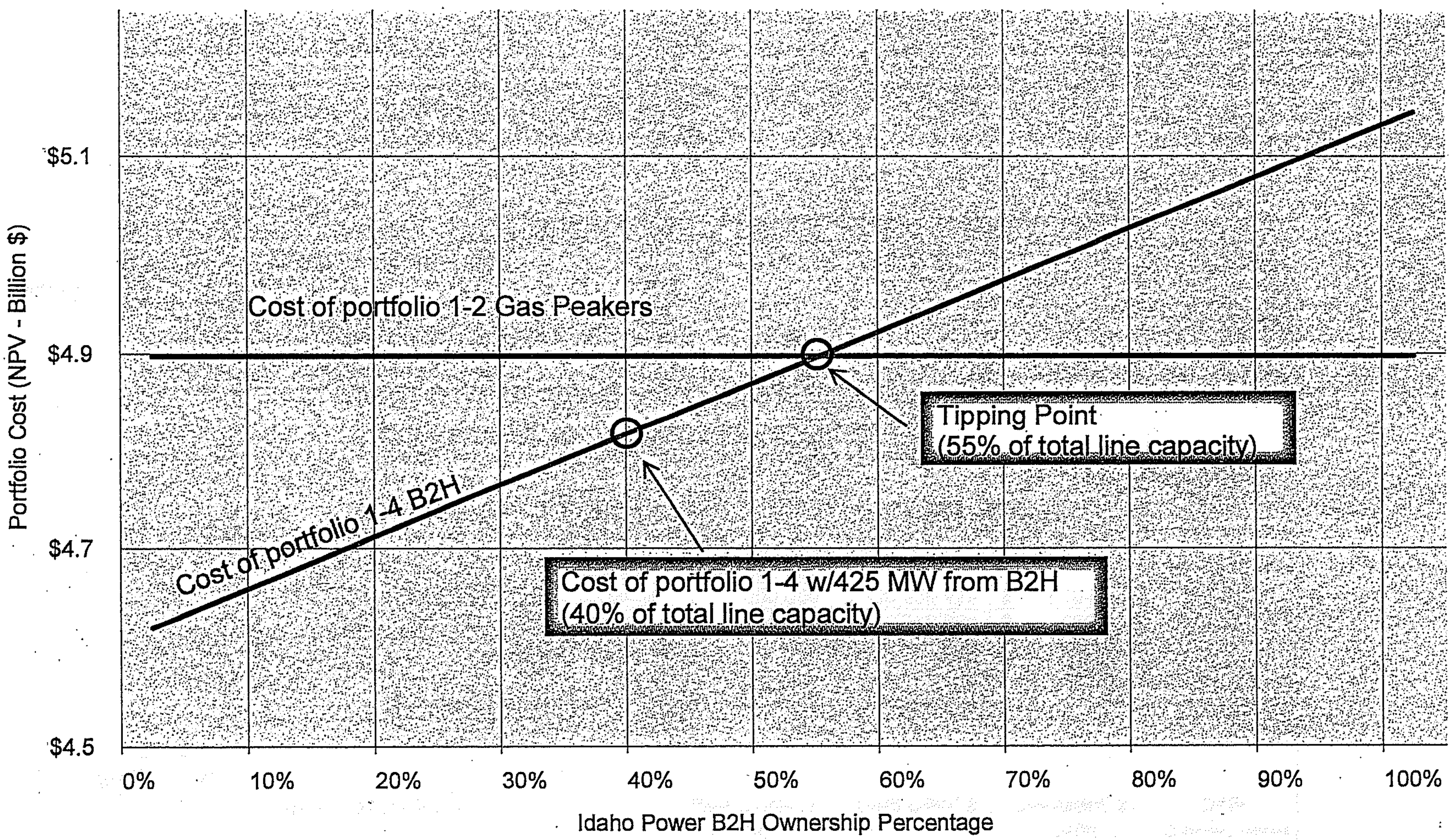
	$ 210.00	Million 40% B2H NPV
	$ 525.00	
0.5250	$ 525.00	check
	$ 210.00	check
0.2100		

Line Slope
0.0263

40% of transmission capacity Idaho Power Subscription B2H

	Portfolio 1-4 (425 MW) Fully Subscribed	Outbound not sold Fully Subscribed			NPV Outbound Sold	NPV outbound Not Sold
2010	0	0	0	0		
2011	0	0	0	0		
2012	0	0	0	0		
2013	0	0	0	0		
2014	0	0	0	0		
2015	$ 16,520,081	$ 32,261,593	0	0		
2016	$ 16,520,081	$ 32,261,593	0	0		
2017	$ 16,520,081	$ 32,261,593	0	0		
2018	$ 16,520,081	$ 32,261,593	0	0		
2019	$ 16,520,081	$ 32,261,593	0	0	$48,365,600	$94,451,794
2020	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2021	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2022	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2023	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2024	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2025	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2026	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2027	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2028	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593		
2029	$ 16,520,081	$ 32,261,593	$ 16,520,081	$ 32,261,593	$59,148,872.33	$115,510,138.56
	$107,514,472.11	$209,961,933.05			$107,514,472.11	$209,961,933.05

Attachment - Supplemental Response Staff DR 16



Boardman - Hemingway 500 kV Line Estimate - High				
Conceptual Level Project Cost Estimate Lines Contingency %:	21%			
AFUDC %:	7%			
Gen w/o overhead %:	10%			
March 2010 IPCo Share %:	100%			
Location & Description	**Transmission Line Costs, $**	**Total Cost, $**	**Total Cost/Mile, $**	**Commitment Date**
Transmission Lines:				
Boardman - Hemingway 500 kV Line				
Line length (miles):	300			
Permitting & Engineering Price	$ 30,000,000	$ 41,315,677		Apr-10
ROW Price/mile	$ 150,000	$ 61,973,515	$ 206,578	Jan-12
Mitigation Price/mile	$ 150,000	$ 61,973,515	$ 206,578	Jun-13
Lattice Structure Material Price/mile:	$ 500,000	$ 206,578,384	$ 688,595	Jun-12
Lattice Structure Labor Price/mile:	$ 800,000	$ 330,525,415	$ 1,101,751	Jun-13
Substations	$ 56,702,685			
Subtotal ==>	**$ 566,702,685**			
Contingency:	$ 117,414,692			
AFUDC:	$ 39,669,188			
IPC Capital work order overhead:	$ 56,670,269			
TOTAL ESTIMATED PROJECT COST ==>	**$ 780,456,833**			
TOTAL PROJECT COST/MILE ==>	**$ 2,601,523**			
Notes:				
1. All estimates are conceptual level estimates.				
2. Commitment dates are preliminary and based on June 2015 in-service date.				

Attachment - Supplemental Response Staff DR 16

LC 50 - DR16 High Estimate B2H

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 1-4 with additional 3rd party subscription

	Project		Capital Cost
	B2H 19% owned by IPCo (425/2300)	$	110,869,565
130.08%	B2H 19% owned by IPCo (425/2300)	$	144,214,850

450 Market Purchase		included in B2H
$	600,000,000	Estimate used in IRP
$	780,456,833	High Estimate for sensitivity

Annual Revenue Requirements

Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**144,214,850**
Ratio of New Revenue Requirements/New Capital		0.160
New Revenue Requirements for Project(s)	$	23,084,415
New Net Revenue Requirements	$	112,140,872

System Use (in MW)

Existing System Peak Demand	5,627
Future additional IPC Network Use	**425**
New System Demand—Including new uses	6,052

Point-To-Point Transmission Rate

a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	18.53

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)

Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(2,990,342)

Network Transmission Revenue Requirements

a) **Existing**			
BPA Load Ratio Share	$	4,237,114	
Long-Term PTP Revenue	$	7,375,757	
Legacy Contract Revenue	$	6,742,822	
Assigned to IPC Retail Load Service	$	70,700,764	
b) **Future - B2H with additional participation**			
BPA Load Ratio Share	$	4,760,071	
Long-Term PTP Revenue	$	8,534,110	
Legacy Contract Revenue	$	6,742,822	
Assigned to IPC Retail Load Service	$	92,103,868	
Net change	**$**	**21,403,104**	High Value
Net change	$	16,520,080	Original Value

Attachment - Supplemental Response Staff DR 16

Idaho Power Ownership of B2H	1-4 IRP	1-4 Hi B2H$	1-4 Hi gas Hi B2H$	1-4 Hi gas	1-4 Low gas	1-2 Exp Gas	1-2 Hi Gas	1-2 Low Gas
	1-4 Boardman to Hemingway					1-2 Gas Peaker		
0.0%	2.0199	2.0199	1.9822	1.9822	2.1959	2.2814	2.23770	2.25445
5.0%	2.0547	2.0552	2.0174	2.0170	2.2307	2.2814	2.23770	2.25445
10.0%	2.0896	2.0904	2.0527	2.0518	2.2655	2.2814	2.23770	2.25445
15.0%	2.1244	2.1257	2.0879	2.0866	2.3004	2.2814	2.23770	2.25445
20.0%	2.1592	2.1609	2.1232	2.1214	2.3352	2.2814	2.23770	2.25445
25.0%	2.1940	2.1962	2.1584	2.1563	2.3700	2.2814	2.23770	2.25445
30.0%	2.2289	2.2314	2.1937	2.1911	2.4048	2.2814	2.23770	2.25445
35.0%	2.2637	2.2667	2.2289	2.2259	2.4397	2.2814	2.23770	2.25445
40.0%	2.2985	2.3019	2.2642	2.2607	2.4745	2.2814	2.23770	2.25445
45.0%	2.3333	2.3372	2.2994	2.2956	2.5093	2.2814	2.23770	2.25445
50.0%	2.3682	2.3724	2.3347	2.3304	2.5441	2.2814	2.23770	2.25445
55.0%	2.4030	2.4077	2.3699	2.3652	2.5790	2.2814	2.23770	2.25445
60.0%	2.4378	2.4429	2.4052	2.4000	2.6138	2.2814	2.23770	2.25445
65.0%	2.4726	2.4782	2.4404	2.4349	2.6486	2.2814	2.23770	2.25445
70.0%	2.5074	2.5134	2.4757	2.4697	2.6834	2.2814	2.23770	2.25445
75.0%	2.5423	2.5487	2.5109	2.5045	2.7182	2.2814	2.23770	2.25445
80.0%	2.5771	2.5839	2.5462	2.5393	2.7531	2.2814	2.23770	2.25445
85.0%	2.6119	2.6192	2.5814	2.5741	2.7879	2.2814	2.23770	2.25445
90.0%	2.6467	2.6544	2.6167	2.6090	2.8227	2.2814	2.23770	2.25445
85.0%	2.6818	2.6897	2.6519	2.6438	2.8575	2.2814	2.23770	2.25445
100.0%	2.7164	2.7249	2.6872	2.6786	2.8924	2.2814	2.23770	2.25445
	Source: 2009 IRP Appendix C Page 16. 1-4 B2H Expected Portfolio Cost.	(0.278587)				Source: 2009 IRP Appendix C Page 16. 1-2 Gas (Peaker)		

Idaho Power Ownership of B2H	2-4 exp gas	2-4 Hi gas	2-4 Low gas	2-4 Exp gas	2-4 Hi Gas	2-4 Low Gas
	2-4 Wind & Peakers			1-2 no B2H		
0.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
5.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
10.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
15.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
20.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
25.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
30.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
35.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
40.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
45.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
50.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
55.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
60.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
65.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
70.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
75.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
80.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
85.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
90.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
85.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
100.0%	2.59989	2.73780	2.31897	2.61701	2.69789	2.51022
	Source: 2009 IRP Appendix C Page 20. 2-4 Wind & Peakers			Source: Original Aurora run for tipping chart. All previous 11-20 year runs had B2H. Removed B2H from NTTG long term plan		

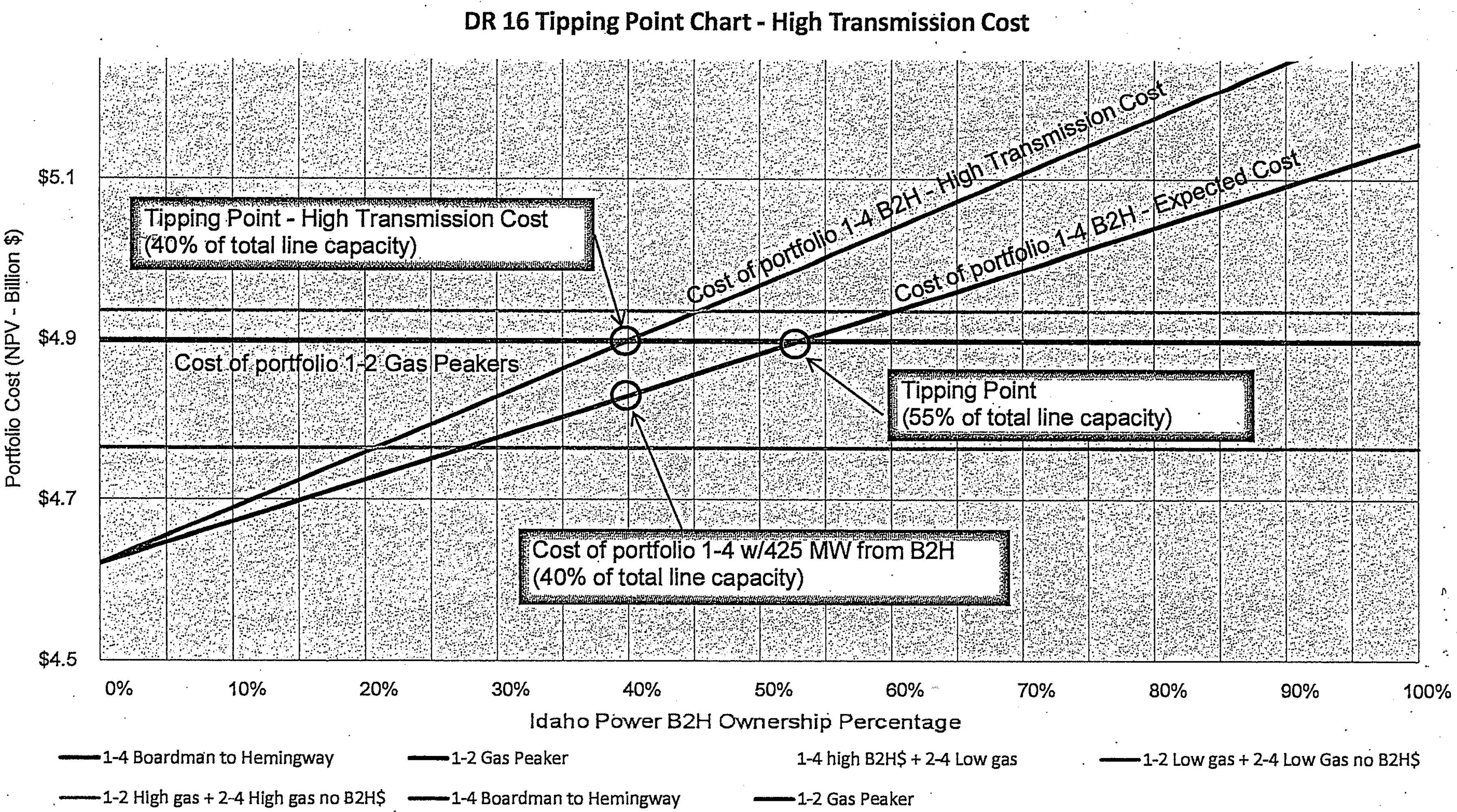
Idaho Power Ownership of B2H	1-4 + 2-4 Base Case	1-2 + 2-4 (1-2 no B2H$)	1-4 high B2H$ + 2-4 Low gas	1-2 Low gas + 2-4 Low Gas no B2H$	1-4 exp B2H$ High gas + 2-4 High gas	1-2 High gas + 2-4 High gas no B2H$	1-4 exp T Low gas + 2-4 Low Gas	1-2 Low gas + 2-4 Low gas no B2H$
	1-4 Boardman to Hemingway	1-2 Gas Peaker						
0.0%	4.6198	4.8984	4.33889	4.76467	4.76772	4.93559	4.51486	4.76467
5.0%	4.6546	4.8984	4.37414	4.76467	4.79297	4.93559	4.54969	4.76467
10.0%	4.6895	4.8984	4.40939	4.76467	4.82822	4.93559	4.58451	4.76467
15.0%	4.7243	4.8984	4.44464	4.76467	4.86347	4.93559	4.61933	4.76467
20.0%	4.7591	4.8984	4.47989	4.76467	4.89872	4.93559	4.65416	4.76467
25.0%	4.7939	4.8984	4.51514	4.76467	4.93397	4.93559	4.68898	4.76467
30.0%	4.8288	4.8984	4.55039	4.76467	4.96922	4.93559	4.72380	4.76467
35.0%	4.8636	4.8984	4.58564	4.76467	5.00447	4.93559	4.75863	4.76467
40.0%	4.8984	4.8984	4.62089	4.76467	5.03972	4.93559	4.79345	4.76467
45.0%	4.9332	4.8984	4.65614	4.76467	5.07497	4.93559	4.82827	4.76467
50.0%	4.9680	4.8984	4.69139	4.76467	5.11022	4.93559	4.86310	4.76467
55.0%	5.0029	4.8984	4.72664	4.76467	5.14547	4.93559	4.89792	4.76467
60.0%	5.0377	4.8984	4.76189	4.76467	5.18072	4.93559	4.93274	4.76467
65.0%	5.0725	4.8984	4.79714	4.76467	5.21597	4.93559	4.96757	4.76467
70.0%	5.1073	4.8984	4.83239	4.76467	5.25122	4.93559	5.00239	4.76467
75.0%	5.1422	4.8984	4.86764	4.76467	5.28647	4.93559	5.03721	4.76467
80.0%	5.1770	4.8984	4.90289	4.76467	5.32172	4.93559	5.07204	4.76467
85.0%	5.2118	4.8984	4.93814	4.76467	5.35697	4.93559	5.10686	4.76467
90.0%	5.2466	4.8984	4.97339	4.76467	5.39222	4.93559	5.14168	4.76467
85.0%	5.2815	4.8984	5.00864	4.76467	5.42747	4.93559	5.17651	4.76467
100.0%	5.3163	4.8984	5.04389	4.76467	5.46272	4.93559	5.21133	4.76467

	$ 278.59	$ 282.00	Million 40% B2H NPV	
	$ 696.47	$ 705.00		
0.6965	$ 696.47	$ 705.00	check	
	$ 278.68	$ 282.00	check	
0.2788				
	Line Slope			
	0.0348	0.0353		

40% of transmission capacity Idaho Power Subscription B2H

	Portfolio 1-4 (425 M Outbound not sold) Fully Subscribed	Fully Subscribed	Portfolio 1-4 (425 MW) Fully Subscribed	Outbound not sold Fully Subscribed
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	0	0	0	0
2015	$ 16,520,081	$ 32,261,593	$ 21,403,104	$ 42,806,208
2016	$ 16,520,081	$ 32,261,593	$ 21,403,104	$ 42,806,208
2017	$ 16,520,081	$ 32,261,593	$ 21,403,104	$ 42,806,208
2016	$ 16,520,081	$ 32,261,593	$ 21,403,104	$ 42,806,208
2018	$ 16,520,081	$ 32,261,593	$ 21,403,104	$ 42,806,208
2020	$ 16,520,081	$ 32,261,593	$ 21,403,104	$ 42,806,208
2021	$ 16,520,081	$ 32,261,593	$ 21,403,104	$ 42,806,208
2022	$ 16,520,081	$ 32,261,593	$ 21,403,104	$ 42,806,208
2023	$ 16,520,081	$ 32,261,593	$ 21,403,104	$ 42,806,208
2024	$ 16,520,081	$ 32,261,593	$ 21,403,104	$ 42,806,208
2025	$ 16,520,081	$ 32,261,593	$ 21,403,104	$ 42,806,208
2026	$ 16,520,081	$ 32,261,593	$ 21,403,104	$ 42,806,208
2027	$ 16,520,081	$ 32,261,593	$ 21,403,104	$ 42,806,208
2028	$ 16,520,081	$ 32,261,593	$ 21,403,104	$ 42,806,208
2029	$ 16,520,081	$ 32,261,593	$ 21,403,104	$ 42,806,208
	$107,514,472	$209,981,933	$139,293,714	$278,587,428

Attachment - Supplemental Response Staff DR 16



BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Idaho Power Company's Response to
Intervenor and Public Comments in its
2009 Integrated Resource Plan

Exhibit No. 2

May 19, 2010

Peak-Hour	2010												2011											
Load and Resource Balance	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**
Load Forecast (95th%)—w/EE DSM	(2,455)	(2,402)	(2,103)	(1,871)	(2,761)	(3,318)	(3,460)	(3,138)	(2,978)	(2,088)	(2,302)	(2,695)	(2,559)	(2,486)	(2,191)	(1,948)	(2,846)	(3,395)	(3,560)	(3,185)	(3,027)	(2,133)	(2,353)	(2,733)
Existing DSM (Irrigation Timer)	0	0	0	0	0	8	8	0	0	0	0	0	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	59	59	51	0	0	0	0	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,455)	(2,402)	(2,103)	(1,871)	(2,761)	(3,259)	(3,401)	(3,088)	(2,978)	(2,088)	(2,302)	(2,695)	(2,559)	(2,486)	(2,191)	(1,948)	(2,846)	(3,338)	(3,503)	(3,134)	(3,027)	(2,133)	(2,353)	(2,733)
Existing Resources																								
Coal (w/Curtailment)	963	963	963	676	621	963	967	967	967	967	967	967	967	967	967	680	790	967	972	972	972	972	972	972
Hydro (90th%)—HCC	1,131	945	670	690	1,181	1,106	1,040	945	1,035	835	600	785	1,107	900	670	690	1,179	1,110	1,035	945	1,090	780	600	785
Hydro (90th%)—Other	203	207	196	213	289	306	246	236	217	210	198	204	203	206	196	213	289	306	246	236	216	210	198	204
Sho-Ban Water Lease	0	0	0	0	0	0	42	0	0	0	0	0	0	0	0	0	0	0	47	0	0	0	0	0
Total Hydro	1,335	1,152	866	903	1,470	1,413	1,328	1,181	1,252	1,045	798	989	1,310	1,106	866	903	1,467	1,416	1,328	1,181	1,306	990	798	989
CSPP (PURPA)	43	42	46	70	121	129	133	124	102	82	58	55	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements																								
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	83	83	83	0	0	0	0	0	0	0	0	0	83	83	83	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	75	75	0	0	0	0	0	0	0	0	0	0	75	75	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	98	223	223	15	15	15	15	15	15	15	15	15	98	173	173	15	15	15	15
Firm Pacific NW Import Capability	99	229	212	205	414	302	122	255	291	0	535	443	216	346	288	270	406	287	105	247	287	73	530	440
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,871**	**2,816**	**2,518**	**2,286**	**3,057**	**3,321**	**3,190**	**3,166**	**3,042**	**2,526**	**2,789**	**2,885**	**2,976**	**2,901**	**2,606**	**2,363**	**3,223**	**3,322**	**3,135**	**3,121**	**3,106**	**2,548**	**2,790**	**2,887**
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(212)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(17)**	**(368)**	**(13)**	**0**	**0**	**0**	**0**
2006 IRP Resources	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**
2012 Wind RFP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Langley Gulch	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(212)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(17)**	**(368)**	**(13)**	**0**	**0**	**0**	**0**
2009 IRP DSM	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**
Commercial (FlexPeak)	0	0	0	0	0	40	40	40	0	0	0	0	0	0	0	0	0	45	45	45	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	212	212	0	0	0	0	0	0	0	0	0	0	244	244	0	0	0	0	0
Energy Efficiency Peak Reduction	3	3	3	3	3	3	3	3	3	3	3	3	7	7	7	7	7	7	7	7	7	7	7	7
Total New DSM Peak Reduction	3	3	3	3	3	254	254	42	3	3	3	3	7	7	7	7	7	296	296	52	7	7	7	7
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(71)**	**0**	**0**	**0**	**0**	**0**
2009 IRP Resources	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**
2015 Boardman–Hemingway Transmission																								
2015 Shoshone Falls Upgrade (49 MW)																								
2017 Boardman–Hemingway Transmission																								
2020 Large Aero (100 MW)																								
2022 Wind (100 MW)																								
2024 Large Aero (2 X 100 MW)																								
2025 Gateway West Transmission																								
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(71)**	**0**	**0**	**0**	**0**	**0**

Peak-Hour	2012											
Load and Resource Balance	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**
Load Forecast (95th%)—w/EE DSM	(2,600)	(2,487)	(2,225)	(1,964)	(2,891)	(3,496)	(3,636)	(3,242)	(3,069)	(2,168)	(2,391)	(2,756)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,600)	(2,487)	(2,225)	(1,964)	(2,891)	(3,440)	(3,579)	(3,192)	(3,069)	(2,168)	(2,391)	(2,756)
Existing Resources												
Coal (w/Curtailment)	972	972	933	663	751	972	978	978	978	798	978	978
Hydro (90th%)—HCC	1,106	897	670	690	1,170	1,056	1,035	945	1,090	780	510	785
Hydro (90th%)—Other	203	206	196	213	289	306	245	235	216	210	198	203
Sho-Ban Water Lease	0	0	0	0	0	0	48	0	0	0	0	0
Total Hydro	1,308	1,103	866	903	1,459	1,363	1,328	1,180	1,306	990	708	988
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	83	83	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	98	98	15	15	15	15
Firm Pacific NW Import Capability	254	348	317	160	396	263	97	240	284	102	528	437
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**3,017**	**2,904**	**2,601**	**2,236**	**3,166**	**3,166**	**3,059**	**3,045**	**3,109**	**2,403**	**2,704**	**2,889**
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(274)**	**(521)**	**(147)**	**0**	**0**	**0**	**0**
2006 IRP Resources	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	0	0	0	0	0	0	300	300	300	300	300	300
Geothermal	0	0	0	0	0	0	0	0	0	20	20	20
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(266)**	**(213)**	**0**	**0**	**0**	**0**	**0**
2009 IRP DSM	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	12	12	12	12	12	12	12	12	12	12	12	12
Total New DSM Peak Reduction	12	12	12	12	12	323	323	69	12	12	12	12
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
2009 IRP Resources	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**
2015 Boardman–Hemingway Transmission												
2015 Shoshone Falls Upgrade (49 MW)												
2017 Boardman–Hemingway Transmission												
2020 Large Aero (100 MW)												
2022 Wind (100 MW)												
2024 Large Aero (2 X 100 MW)												
2025 Gateway West Transmission												
2026 Large Aero (2 X 100 MW)												
2027 Wind (2 X 200 MW)												
2028 Large Aero (4 X 100 MW)												
2029 Large Aero (5 X 100 MW)												
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Peak-Hour	2013											
Load and Resource Balance	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**
Load Forecast (95th%)—w/EE DSM	(2,560)	(2,496)	(2,203)	(1,922)	(2,915)	(3,541)	(3,726)	(3,296)	(3,127)	(2,177)	(2,389)	(2,703)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,560)	(2,496)	(2,203)	(1,922)	(2,915)	(3,484)	(3,669)	(3,246)	(3,127)	(2,177)	(2,389)	(2,703)
Existing Resources												
Coal (w/Curtailment)	978	978	907	0	744	978	983	983	789	670	983	983
Hydro (90th%)—HCC	1,116	870	670	670	1,170	1,060	1,034	945	1,035	780	600	870
Hydro (90th%)—Other	202	206	195	213	289	306	245	234	216	210	198	203
Sho-Ban Water Lease	0	0	0	0	0	0	48	0	0	0	0	0
Total Hydro	1,319	1,076	865	883	1,459	1,366	1,327	1,179	1,251	990	798	1,073
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	15	15	15	15	15	15
Firm Pacific NW Import Capability	197	377	290	254	389	248	87	234	278	106	525	443
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,977**	**2,913**	**2,547**	**1,647**	**3,151**	**3,161**	**2,969**	**2,960**	**2,859**	**2,279**	**2,795**	**2,985**
Monthly Surplus/Deficit	**0**	**0**	**0**	**(276)**	**0**	**(324)**	**(700)**	**(286)**	**(268)**	**0**	**0**	**0**
2006 IRP Resources	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(373)**	**0**	**0**	**0**	**0**	**0**
2009 IRP DSM	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	18	18	18	18	18	18	18	18	18	18	18	18
Total New DSM Peak Reduction	18	18	18	18	18	329	329	75	18	18	18	18
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(44)**	**0**	**0**	**0**	**0**	**0**
2009 IRP Resources	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**
2015 Boardman–Hemingway Transmission												
2015 Shoshone Falls Upgrade (49 MW)												
2017 Boardman–Hemingway Transmission												
2020 Large Aero (100 MW)												
2022 Wind (100 MW)												
2024 Large Aero (2 X 100 MW)												
2025 Gateway West Transmission												
2026 Large Aero (2 X 100 MW)												
2027 Wind (2 X 200 MW)												
2028 Large Aero (4 X 100 MW)												
2029 Large Aero (5 X 100 MW)												
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(44)**	**0**	**0**	**0**	**0**	**0**

Peak-Hour

Load and Resource Balance (2014)	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Load Forecast (95th%)—w/EE DSM	(2,594)	(2,516)	(2,230)	(1,944)	(2,946)	(3,593)	(3,789)	(3,359)	(3,169)	(2,193)	(2,415)	(2,748)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,594)	(2,516)	(2,230)	(1,944)	(2,946)	(3,536)	(3,732)	(3,308)	(3,169)	(2,193)	(2,415)	(2,748)
Existing Resources												
Coal (w/Curtailment)	983	983	803	0	728	913	983	983	789	670	983	983
Hydro (90th%)—HCC	1,122	845	670	585	1,135	1,066	1,005	945	1,035	595	600	870
Hydro (90th%)—Other	202	205	195	213	288	305	243	232	215	209	197	202
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,323	1,050	865	798	1,422	1,371	1,248	1,177	1,250	804	797	1,072
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	15	15	15	15	15	15
Firm Pacific NW Import Capability	222	444	523	356	380	237	79	218	276	308	523	439
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**3,011**	**2,959**	**2,676**	**1,663**	**3,090**	**3,090**	**2,882**	**2,941**	**2,856**	**2,295**	**2,793**	**2,980**
Monthly Surplus/Deficit	**0**	**0**	**0**	**(281)**	**0**	**(447)**	**(850)**	**(367)**	**(313)**	**0**	**0**	**0**
2006 IRP Resources	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(119)**	**(522)**	**(40)**	**0**	**0**	**0**	**0**
2009 IRP DSM	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	24	24	24	24	24	24	24	24	24	24	25	24
Total New DSM Peak Reduction	24	24	24	24	24	335	335	81	24	24	25	24
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(188)**	**0**	**0**	**0**	**0**	**0**
2009 IRP Resources	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**
2015 Boardman–Hemingway Transmission												
2015 Shoshone Falls Upgrade (49 MW)												
2017 Boardman–Hemingway Transmission												
2020 Large Aero (100 MW)												
2022 Wind (100 MW)												
2024 Large Aero (2 X 100 MW)												
2025 Gateway West Transmission												
2026 Large Aero (2 X 100 MW)												
2027 Wind (2 X 200 MW)												
2028 Large Aero (4 X 100 MW)												
2029 Large Aero (5 X 100 MW)												
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(188)**	**0**	**0**	**0**	**0**	**0**

Load and Resource Balance (2015)	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Load Forecast (95th%)—w/EE DSM	(2,583)	(2,509)	(2,226)	(1,931)	(2,970)	(3,640)	(3,843)	(3,396)	(3,211)	(2,200)	(2,421)	(2,742)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,583)	(2,509)	(2,226)	(1,931)	(2,970)	(3,583)	(3,786)	(3,346)	(3,211)	(2,200)	(2,421)	(2,742)
Existing Resources												
Coal (w/Curtailment)	982	982	586	676	725	936	982	982	671	470	982	982
Hydro (90th%)—HCC	1,098	845	670	585	1,187	1,104	1,035	945	1,035	780	600	870
Hydro (90th%)—Other	201	204	194	212	287	296	240	230	214	209	197	201
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,299	1,049	864	797	1,473	1,400	1,275	1,175	1,249	989	797	1,071
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	15	15	15	15	15	15
Firm Pacific NW Import Capability	236	432	517	223	381	242	71	196	267	131	525	439
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**3,000**	**2,944**	**2,452**	**2,206**	**3,139**	**3,146**	**2,900**	**2,916**	**2,728**	**2,103**	**2,793**	**2,978**
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(437)**	**(886)**	**(430)**	**(483)**	**(97)**	**0**	**0**
2006 IRP Resources	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(110)**	**(558)**	**(102)**	**(156)**	**0**	**0**	**0**
2009 IRP DSM	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	31	31	31	31	31	31	31	31	31	31	31	31
Total New DSM Peak Reduction	31	31	31	31	31	341	341	87	31	31	31	31
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(217)**	**(15)**	**(125)**	**0**	**0**	**0**
2009 IRP Resources	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**
2015 Boardman–Hemingway Transmission						250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)										0	0	1
2017 Boardman–Hemingway Transmission												
2020 Large Aero (100 MW)												
2022 Wind (100 MW)												
2024 Large Aero (2 X 100 MW)												
2025 Gateway West Transmission												
2026 Large Aero (2 X 100 MW)												
2027 Wind (2 X 200 MW)												
2028 Large Aero (4 X 100 MW)												
2029 Large Aero (5 X 100 MW)												
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Peak-Hour	2016											
Load and Resource Balance	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**
Load Forecast (95th%)—w/EE DSM	(2,580)	(2,507)	(2,228)	(1,924)	(2,993)	(3,686)	(3,895)	(3,437)	(3,252)	(2,207)	(2,430)	(2,745)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,580)	(2,507)	(2,228)	(1,924)	(2,993)	(3,629)	(3,838)	(3,386)	(3,252)	(2,207)	(2,430)	(2,745)
Existing Resources												
Coal (w/Curtailment)	980	980	586	602	635	936	980	980	671	470	980	980
Hydro (90th%)—HCC	1,115	835	585	780	1,181	1,117	1,035	945	1,035	780	600	870
Hydro (90th%)—Other	200	203	193	212	286	294	238	226	213	208	196	201
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,315	1,038	778	992	1,467	1,411	1,273	1,171	1,248	988	796	1,071
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	15	15	15	15	15	15
Firm Pacific NW Import Capability	219	451	400	259	376	229	65	190	265	141	524	440
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,997**	**2,951**	**2,249**	**2,363**	**3,038**	**3,144**	**2,891**	**2,905**	**2,725**	**2,112**	**2,790**	**2,977**
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(485)**	**(948)**	**(481)**	**(526)**	**(95)**	**0**	**0**
2006 IRP Resources	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	0	0	0	0	0	0	0	0	0	20	20	20
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(158)**	**(620)**	**(154)**	**(199)**	**0**	**0**	**0**
2009 IRP DSM	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	38	37	37	37	38	37	37	37	38	38	38	37
Total New DSM Peak Reduction	38	37	37	37	38	348	348	94	38	38	38	37
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(272)**	**(60)**	**(161)**	**0**	**0**	**0**
2009 IRP Resources	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	2	2	0	0	3	10	0	0	0	0	0	1
2017 Boardman–Hemingway Transmission												
2020 Large Aero (100 MW)												
2022 Wind (100 MW)												
2024 Large Aero (2 X 100 MW)												
2025 Gateway West Transmission												
2026 Large Aero (2 X 100 MW)												
2027 Wind (2 X 200 MW)												
2028 Large Aero (4 X 100 MW)												
2029 Large Aero (5 X 100 MW)												
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(22)**	**0**	**0**	**0**	**0**	**0**

Peak-Hour	2017											
Load and Resource Balance	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**
Load Forecast (95th%)—w/EE DSM	(2,578)	(2,504)	(2,231)	(1,920)	(3,018)	(3,733)	(3,949)	(3,480)	(3,293)	(2,215)	(2,439)	(2,751)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,578)	(2,504)	(2,231)	(1,920)	(3,018)	(3,676)	(3,893)	(3,429)	(3,293)	(2,215)	(2,439)	(2,751)
Existing Resources												
Coal (w/Curtailment)	980	980	586	569	543	936	980	980	671	470	908	980
Hydro (90th%)—HCC	1,117	845	585	785	1,184	1,060	1,005	945	1,085	780	600	870
Hydro (90th%)—Other	200	202	192	211	285	292	237	223	212	207	196	200
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,317	1,047	777	996	1,469	1,353	1,242	1,168	1,297	987	796	1,070
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	15	15	15	15	15	15
Firm Pacific NW Import Capability	215	431	404	0	370	219	58	182	262	150	524	440
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,995**	**2,940**	**2,252**	**2,075**	**2,942**	**3,076**	**2,853**	**2,894**	**2,771**	**2,120**	**2,716**	**2,975**
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**(76)**	**(600)**	**(1,039)**	**(535)**	**(522)**	**(95)**	**0**	**0**
2006 IRP Resources	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(252)**	**(692)**	**(188)**	**(175)**	**0**	**0**	**0**
2009 IRP DSM	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	44	44	44	44	45	44	44	44	44	44	44	45
Total New DSM Peak Reduction	44	44	44	44	45	355	355	101	44	44	44	45
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(337)**	**(87)**	**(130)**	**0**	**0**	**0**
2009 IRP Resources	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	2	2	0	0	3	10	0	0	0	0	0	1
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)												
2022 Wind (100 MW)												
2024 Large Aero (2 X 100 MW)												
2025 Gateway West Transmission												
2026 Large Aero (2 X 100 MW)												
2027 Wind (2 X 200 MW)												
2028 Large Aero (4 X 100 MW)												
2029 Large Aero (5 X 100 MW)												
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Peak-Hour						2018													2019						
Load and Resource Balance	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**
Load Forecast (95th%)—w/EE DSM	(2,576)	(2,501)	(2,233)	(1,915)	(3,042)	(3,780)	(4,003)	(3,523)	(3,334)	(2,223)	(2,448)	(2,759)	(2,578)	(2,501)	(2,238)	(1,915)	(3,067)	(3,827)	(4,060)	(3,570)	(3,374)	(2,230)	(2,459)	(2,773)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,576)	(2,501)	(2,233)	(1,915)	(3,042)	(3,723)	(3,947)	(3,472)	(3,334)	(2,223)	(2,448)	(2,759)	(2,578)	(2,501)	(2,238)	(1,915)	(3,067)	(3,770)	(4,003)	(3,520)	(3,374)	(2,230)	(2,459)	(2,773)
Existing Resources																								
Coal (w/Curtailment)	980	980	586	376	525	936	977	977	671	470	908	977	977	977	486	237	405	916	977	977	671	314	775	977
Hydro (90th%)—HCC	1,113	845	585	585	1,175	1,041	1,005	945	1,080	780	510	870	1,114	845	700	585	1,173	1,039	1,005	945	1,035	760	600	1,187
Hydro (90th%)—Other	199	201	192	211	284	290	230	222	208	207	195	200	198	201	191	211	284	287	227	221	207	206	195	200
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,312	1,046	777	796	1,460	1,331	1,235	1,167	1,288	987	705	1,070	1,313	1,046	891	796	1,457	1,326	1,232	1,166	1,242	966	795	1,387
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements																								
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Firm Pacific NW Import Capability	218	426	406	166	363	206	54	179	256	161	525	439	222	432	300	335	355	193	48	174	249	189	520	312
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,993**	**2,934**	**2,254**	**1,848**	**2,908**	**3,041**	**2,838**	**2,887**	**2,756**	**2,131**	**2,627**	**2,971**	**2,995**	**2,937**	**2,162**	**1,878**	**2,777**	**3,003**	**2,830**	**2,881**	**2,703**	**1,982**	**2,579**	**3,161**
Monthly Surplus/Deficit	**0**	**0**	**0**	**(67)**	**(135)**	**(682)**	**(1,108)**	**(586)**	**(578)**	**(92)**	**0**	**0**	**0**	**0**	**(76)**	**(37)**	**(290)**	**(768)**	**(1,173)**	**(639)**	**(671)**	**(248)**	**0**	**0**
2006 IRP Resources	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(335)**	**(761)**	**(238)**	**(231)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(420)**	**(826)**	**(291)**	**(324)**	**0**	**0**	**0**
2009 IRP DSM	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	51	51	51	51	52	51	51	51	52	51	51	52	59	58	59	58	59	58	58	58	59	58	59	59
Total New DSM Peak Reduction	51	51	51	51	52	362	362	108	52	51	51	52	59	58	59	58	59	369	369	115	59	58	59	59
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(399)**	**(131)**	**(179)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(51)**	**(457)**	**(176)**	**(265)**	**0**	**0**	**0**
2009 IRP Resources	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	2	2	0	0	3	10	0	0	0	0	0	1	2	2	0	0	3	10	0	0	0	0	0	1
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)																								
2022 Wind (100 MW)																								
2024 Large Aero (2 X 100 MW)																								
2025 Gateway West Transmission																								
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(32)**	**0**	**0**	**0**	**0**	**0**

Peak-Hour	2020											
Load and Resource Balance	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**
Load Forecast (95th%)—w/EE DSM	(2,586)	(2,494)	(2,246)	(1,918)	(3,092)	(3,876)	(4,118)	(3,621)	(3,417)	(2,239)	(2,470)	(2,786)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,586)	(2,494)	(2,246)	(1,918)	(3,092)	(3,819)	(4,061)	(3,570)	(3,417)	(2,239)	(2,470)	(2,786)
Existing Resources												
Coal (w/Curtailment)	977	977	513	237	575	977	977	977	671	314	802	977
Hydro (90th%)—HCC	925	965	700	585	1,181	1,035	1,005	945	1,035	505	600	785
Hydro (90th%)—Other	198	200	190	210	283	286	224	220	205	206	194	199
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,123	1,165	890	795	1,463	1,321	1,229	1,165	1,240	711	794	984
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	15	15	15	15	15	15
Firm Pacific NW Import Capability	452	287	309	339	375	191	41	159	244	481	522	436
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**3,034**	**2,911**	**2,197**	**1,881**	**2,973**	**3,057**	**2,820**	**2,864**	**2,697**	**2,019**	**2,607**	**2,883**
Monthly Surplus/Deficit	**0**	**0**	**(49)**	**(38)**	**(119)**	**(762)**	**(1,241)**	**(706)**	**(721)**	**(220)**	**0**	**0**
2006 IRP Resources	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(414)**	**(893)**	**(358)**	**(373)**	**0**	**0**	**0**
2009 IRP DSM	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	66	66	66	66	66	66	66	66	66	66	66	66
Total New DSM Peak Reduction	66	66	66	66	66	376	376	122	66	66	66	66
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(38)**	**(517)**	**(236)**	**(308)**	**0**	**0**	**0**
2009 IRP Resources	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	2	2	0	0	3	10	0	0	0	0	0	1
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)	100	100	100	100	100	100	100	100	100	100	100	100
2022 Wind (100 MW)												
2024 Large Aero (2 X 100 MW)												
2025 Gateway West Transmission												
2026 Large Aero (2 X 100 MW)												
2027 Wind (2 X 200 MW)												
2028 Large Aero (4 X 100 MW)												
2029 Large Aero (5 X 100 MW)												
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Peak-Hour	2021											
Load and Resource Balance	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**
Load Forecast (95th%)—w/EE DSM	(2,547)	(2,481)	(2,229)	(1,889)	(3,109)	(3,916)	(4,160)	(3,642)	(3,458)	(2,239)	(2,466)	(2,754)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,547)	(2,481)	(2,229)	(1,889)	(3,109)	(3,860)	(4,103)	(3,592)	(3,458)	(2,239)	(2,466)	(2,754)
Existing Resources												
Coal (w/Curtailment)	977	977	605	237	485	935	977	977	673	314	592	977
Hydro (90th%)—HCC	1,064	845	700	585	1,178	1,035	1,050	945	1,035	690	600	870
Hydro (90th%)—Other	197	200	190	210	282	282	222	219	204	205	193	198
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,261	1,045	890	795	1,461	1,317	1,272	1,164	1,239	895	793	1,068
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	15	15	15	15	15	15
Firm Pacific NW Import Capability	243	394	292	313	350	189	34	146	228	269	522	439
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,964**	**2,898**	**2,272**	**1,855**	**2,856**	**3,010**	**2,855**	**2,850**	**2,682**	**1,991**	**2,397**	**2,970**
Monthly Surplus/Deficit	**0**	**0**	**0**	**(35)**	**(253)**	**(850)**	**(1,248)**	**(742)**	**(776)**	**(247)**	**(69)**	**0**
2006 IRP Resources	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(503)**	**(900)**	**(394)**	**(429)**	**0**	**0**	**0**
2009 IRP DSM	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	73	73	73	73	74	73	73	73	73	73	73	73
Total New DSM Peak Reduction	73	73	73	73	74	383	383	129	73	73	73	73
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(119)**	**(517)**	**(265)**	**(356)**	**0**	**0**	**0**
2009 IRP Resources	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	2	2	0	0	3	10	0	0	0	0	0	1
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)	100	100	100	100	100	100	100	100	100	100	100	100
2022 Wind (100 MW)												
2024 Large Aero (2 X 100 MW)												
2025 Gateway West Transmission												
2026 Large Aero (2 X 100 MW)												
2027 Wind (2 X 200 MW)												
2028 Large Aero (4 X 100 MW)												
2029 Large Aero (5 X 100 MW)												
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Peak-Hour	2022												2023											
Load and Resource Balance	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**
Load Forecast (95th%)—w/EE DSM	(2,543)	(2,477)	(2,232)	(1,886)	(3,131)	(3,961)	(4,210)	(3,685)	(3,500)	(2,245)	(2,474)	(2,763)	(2,535)	(2,470)	(2,230)	(1,878)	(3,153)	(4,006)	(4,261)	(3,726)	(3,540)	(2,249)	(2,479)	(2,751)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,543)	(2,477)	(2,232)	(1,886)	(3,131)	(3,904)	(4,154)	(3,634)	(3,500)	(2,245)	(2,474)	(2,763)	(2,535)	(2,470)	(2,230)	(1,878)	(3,153)	(3,949)	(4,205)	(3,675)	(3,540)	(2,249)	(2,479)	(2,751)
Existing Resources																								
Coal (w/Curtailment)	977	977	605	0	417	935	977	977	673	314	592	977	977	977	430	0	417	935	977	977	493	314	555	977
Hydro (90th%)—HCC	1,056	815	700	585	1,177	1,035	1,040	945	1,035	750	600	785	1,048	815	785	585	1,104	1,035	1,005	945	1,035	700	600	785
Hydro (90th%)—Other	197	199	189	210	282	279	217	218	204	204	193	198	196	198	188	209	281	277	214	218	203	204	192	197
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,252	1,014	889	795	1,458	1,314	1,257	1,163	1,239	954	793	983	1,244	1,013	973	794	1,385	1,312	1,219	1,163	1,238	904	792	982
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements																								
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Firm Pacific NW Import Capability	248	445	296	311	345	185	28	142	222	216	522	439	248	433	210	303	341	176	23	142	217	270	521	439
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,960**	**2,917**	**2,275**	**1,615**	**2,781**	**3,003**	**2,835**	**2,845**	**2,675**	**1,997**	**2,395**	**2,885**	**2,952**	**2,905**	**2,098**	**1,607**	**2,702**	**2,992**	**2,791**	**2,845**	**2,489**	**2,001**	**2,357**	**2,883**
Monthly Surplus/Deficit	**0**	**0**	**0**	**(272)**	**(350)**	**(901)**	**(1,319)**	**(789)**	**(825)**	**(248)**	**(79)**	**0**	**0**	**0**	**(133)**	**(272)**	**(450)**	**(957)**	**(1,413)**	**(830)**	**(1,051)**	**(248)**	**(122)**	**0**
2006 IRP Resources	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**(2)**	**(554)**	**(972)**	**(441)**	**(477)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(103)**	**(610)**	**(1,066)**	**(483)**	**(704)**	**0**	**0**	**0**
2009 IRP DSM	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	81	80	80	80	81	80	80	80	80	80	80	80	88	87	87	88	88	88	87	88	88	88	88	88
Total New DSM Peak Reduction	81	80	80	80	81	391	390	137	80	80	80	80	88	87	87	88	88	398	398	144	88	88	88	88
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(163)**	**(581)**	**(305)**	**(397)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(15)**	**(212)**	**(668)**	**(339)**	**(616)**	**0**	**0**	**0**
2009 IRP Resources	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	2	2	0	0	3	10	0	0	0	0	0	1	2	2	0	0	3	10	0	0	0	0	0	1
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2022 Wind (100 MW)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
2024 Large Aero (2 X 100 MW)																								
2025 Gateway West Transmission																								
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(51)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(138)**	**0**	**(86)**	**0**	**0**	**0**

Peak-Hour	2024												2025											
Load and Resource Balance	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**
Load Forecast (95th%)—w/EE DSM	(2,467)	(2,454)	(2,193)	(1,830)	(3,164)	(4,039)	(4,290)	(3,728)	(3,580)	(2,244)	(2,461)	(2,688)	(2,471)	(2,430)	(2,201)	(1,835)	(3,186)	(4,084)	(4,341)	(3,776)	(3,622)	(2,251)	(2,471)	(2,710)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,467)	(2,454)	(2,193)	(1,830)	(3,164)	(3,983)	(4,234)	(3,678)	(3,580)	(2,244)	(2,461)	(2,688)	(2,471)	(2,430)	(2,201)	(1,835)	(3,186)	(4,027)	(4,284)	(3,726)	(3,622)	(2,251)	(2,471)	(2,710)
Existing Resources																								
Coal (w/Curtailment)	977	977	430	0	417	935	977	977	403	214	555	977	977	977	311	0	417	935	977	977	403	214	403	977
Hydro (90th%)—HCC	1,043	780	700	585	1,175	1,039	1,005	945	1,035	615	600	785	968	775	700	585	1,173	1,035	1,005	945	1,035	574	600	785
Hydro (90th%)—Other	195	198	188	209	281	275	212	217	202	204	191	197	195	197	187	208	280	266	211	216	201	203	190	196
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,238	978	888	794	1,455	1,314	1,217	1,162	1,237	819	791	982	1,162	972	887	793	1,454	1,301	1,216	1,161	1,236	777	790	981
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements																								
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Firm Pacific NW Import Capability	186	470	258	255	336	172	19	133	209	366	519	445	266	431	267	261	327	169	13	137	205	466	520	443
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,884**	**2,906**	**2,061**	**1,559**	**2,769**	**2,989**	**2,786**	**2,835**	**2,390**	**1,912**	**2,354**	**2,889**	**2,888**	**2,862**	**1,950**	**1,564**	**2,758**	**2,974**	**2,778**	**2,838**	**2,385**	**1,970**	**2,203**	**2,887**
Monthly Surplus/Deficit	**0**	**0**	**(133)**	**(271)**	**(395)**	**(994)**	**(1,448)**	**(843)**	**(1,189)**	**(332)**	**(106)**	**0**	**0**	**0**	**(251)**	**(271)**	**(428)**	**(1,053)**	**(1,506)**	**(888)**	**(1,237)**	**(280)**	**(268)**	**0**
2006 IRP Resources	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**(48)**	**(646)**	**(1,100)**	**(495)**	**(842)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(80)**	**(706)**	**(1,158)**	**(541)**	**(889)**	**0**	**0**	**0**
2009 IRP DSM	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	95	95	95	95	95	95	95	95	96	95	95	96	103	103	103	103	103	103	103	103	103	103	104	103
Total New DSM Peak Reduction	95	95	95	95	95	406	406	152	96	95	95	96	103	103	103	103	103	413	413	159	103	103	104	103
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(241)**	**(694)**	**(343)**	**(746)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(292)**	**(745)**	**(381)**	**(786)**	**0**	**0**	**0**
2009 IRP Resources	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	2	2	0	0	3	10	0	0	0	0	0	1	2	2	0	0	3	10	0	0	0	0	0	1
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2022 Wind (100 MW)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
2024 Large Aero (2 X 100 MW)	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
2025 Gateway West Transmission													100	100	100	100	100	100	100	100	100	100	100	100
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(16)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Peak-Hour	2026											
Load and Resource Balance	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**
Load Forecast (95th%)—w/EE DSM	(2,460)	(2,421)	(2,199)	(1,828)	(3,206)	(4,129)	(4,393)	(3,818)	(3,664)	(2,254)	(2,475)	(2,702)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,460)	(2,421)	(2,199)	(1,828)	(3,206)	(4,072)	(4,336)	(3,768)	(3,664)	(2,254)	(2,475)	(2,702)
Existing Resources												
Coal (w/Curtailment)	977	421	0	0	0	500	977	977	313	0	313	977
Hydro (90th%)—HCC	895	775	700	585	1,173	1,035	1,005	904	1,035	628	605	785
Hydro (90th%)—Other	194	196	186	208	280	261	208	214	201	202	190	195
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,089	971	886	793	1,452	1,296	1,213	1,119	1,236	830	795	980
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	15	15	15	15	15	15
Firm Pacific NW Import Capability	329	412	389	131	329	172	6	125	187	364	522	444
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,878**	**2,286**	**1,760**	**1,434**	**2,341**	**2,536**	**2,769**	**2,784**	**2,277**	**1,708**	**2,119**	**2,887**
Monthly Surplus/Deficit	**0**	**(135)**	**(439)**	**(394)**	**(864)**	**(1,536)**	**(1,567)**	**(984)**	**(1,387)**	**(546)**	**(356)**	**0**
2006 IRP Resources	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
Remaining Monthly Surplus/Deficit	**0**	**0**	**(92)**	**(47)**	**(517)**	**(1,188)**	**(1,220)**	**(636)**	**(1,040)**	**(199)**	**(9)**	**0**
2009 IRP DSM	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	111	111	111	111	112	111	111	111	111	110	112	111
Total New DSM Peak Reduction	111	111	111	111	112	421	421	167	111	110	112	111
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**(405)**	**(767)**	**(798)**	**(469)**	**(929)**	**(88)**	**0**	**0**
2009 IRP Resources	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	2	2	0	0	3	10	0	0	0	0	0	1
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)	100	100	100	100	100	100	100	100	100	100	100	100
2022 Wind (100 MW)	5	5	5	5	5	5	5	5	5	5	5	5
2024 Large Aero (2 X 100 MW)	200	200	200	200	200	200	200	200	200	200	200	200
2025 Gateway West Transmission	100	100	100	100	100	100	100	100	100	100	100	100
2026 Large Aero (2 X 100 MW)	200	200	200	200	200	200	200	200	200	200	200	200
2027 Wind (2 X 200 MW)												
2028 Large Aero (4 X 100 MW)												
2029 Large Aero (5 X 100 MW)												
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Peak-Hour	2027											
Load and Resource Balance	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**Oct-27**	**Nov-27**	**Dec-27**
Load Forecast (95th%)—w/EE DSM	(2,393)	(2,382)	(2,168)	(1,783)	(3,216)	(4,163)	(4,424)	(3,825)	(3,703)	(2,247)	(2,460)	(2,639)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,393)	(2,382)	(2,168)	(1,783)	(3,216)	(4,106)	(4,367)	(3,774)	(3,703)	(2,247)	(2,460)	(2,639)
Existing Resources												
Coal (w/Curtailment)	311	0	0	0	0	500	977	977	34	0	0	846
Hydro (90th%)—HCC	965	690	755	585	1,123	1,035	1,005	945	1,035	632	600	785
Hydro (90th%)—Other	193	196	186	208	280	241	208	213	200	202	189	195
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,158	886	941	793	1,402	1,276	1,213	1,158	1,235	834	789	980
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	15	15	15	15	15	15
Firm Pacific NW Import Capability	193	504	180	210	327	165	2	126	183	343	523	449
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,145**	**1,871**	**1,606**	**1,513**	**2,289**	**2,509**	**2,765**	**2,825**	**1,994**	**1,690**	**1,801**	**2,760**
Monthly Surplus/Deficit	**(248)**	**(511)**	**(562)**	**(270)**	**(927)**	**(1,598)**	**(1,603)**	**(950)**	**(1,709)**	**(557)**	**(659)**	**0**
2006 IRP Resources	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**Oct-27**	**Nov-27**	**Dec-27**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
Remaining Monthly Surplus/Deficit	**0**	**(163)**	**(215)**	**0**	**(579)**	**(1,250)**	**(1,255)**	**(602)**	**(1,361)**	**(209)**	**(311)**	**0**
2009 IRP DSM	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**Oct-27**	**Nov-27**	**Dec-27**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	119	119	118	118	120	119	119	119	119	119	119	119
Total New DSM Peak Reduction	119	119	118	118	120	429	429	175	119	119	119	119
Remaining Monthly Surplus/Deficit	**0**	**(44)**	**(96)**	**0**	**(459)**	**(821)**	**(826)**	**(427)**	**(1,242)**	**(90)**	**(192)**	**0**
2009 IRP Resources	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**Oct-27**	**Nov-27**	**Dec-27**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	2	2	0	0	3	10	0	0	0	0	0	1
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)	100	100	100	100	100	100	100	100	100	100	100	100
2022 Wind (100 MW)	5	5	5	5	5	5	5	5	5	5	5	5
2024 Large Aero (2 X 100 MW)	200	200	200	200	200	200	200	200	200	200	200	200
2025 Gateway West Transmission	100	100	100	100	100	100	100	100	100	100	100	100
2026 Large Aero (2 X 100 MW)	200	200	200	200	200	200	200	200	200	200	200	200
2027 Wind (2 X 200 MW)	20	20	20	20	20	20	20	20	20	20	20	20
2028 Large Aero (4 X 100 MW)												
2029 Large Aero (5 X 100 MW)												
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(192)**	**0**	**0**	**0**

Peak-Hour						2028													2029					
Load and Resource Balance	Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28	Jan-29	Feb-29	Mar-29	Apr-29	May-29	Jun-29	Jul-29	Aug-29	Sep-29	Oct-29	Nov-29	Dec-29
Load Forecast (95th%)—w/EE DSM	(2,354)	(2,345)	(2,152)	(1,756)	(3,231)	(4,199)	(4,460)	(3,846)	(3,743)	(2,245)	(2,454)	(2,595)	(2,248)	(2,296)	(2,100)	(1,687)	(3,234)	(4,225)	(4,475)	(3,828)	(3,780)	(2,234)	(2,424)	(2,493)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,354)	(2,345)	(2,152)	(1,756)	(3,231)	(4,143)	(4,403)	(3,795)	(3,743)	(2,245)	(2,454)	(2,595)	(2,248)	(2,296)	(2,100)	(1,687)	(3,234)	(4,169)	(4,419)	(3,778)	(3,780)	(2,234)	(2,424)	(2,493)
Existing Resources																								
Coal (w/Curtailment)	563	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro (90th%)—HCC	962	775	700	575	1,171	1,035	1,005	860	1,035	571	600	785	893	775	700	575	1,170	1,035	1,005	945	1,035	625	600	785
Hydro (90th%)—Other	193	195	185	207	279	239	206	211	200	201	189	194	197	199	184	207	279	237	206	210	199	201	188	193
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,155	970	885	782	1,450	1,274	1,211	1,071	1,235	772	789	979	1,090	974	884	782	1,449	1,272	1,211	1,155	1,234	826	788	978
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements																								
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Firm Pacific NW Import Capability	157	333	220	195	324	163	0	120	176	462	518	454	117	280	169	135	321	159	0	129	170	333	526	463
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,358**	**1,785**	**1,590**	**1,487**	**2,334**	**2,006**	**1,784**	**1,754**	**1,951**	**1,748**	**1,796**	**1,919**	**1,690**	**1,736**	**1,538**	**1,427**	**2,330**	**2,000**	**1,783**	**1,847**	**1,946**	**1,672**	**1,803**	**1,927**
Monthly Surplus/Deficit	**0**	**(561)**	**(562)**	**(269)**	**(897)**	**(2,137)**	**(2,619)**	**(2,041)**	**(1,791)**	**(497)**	**(658)**	**(676)**	**(558)**	**(560)**	**(562)**	**(261)**	**(904)**	**(2,169)**	**(2,636)**	**(1,931)**	**(1,835)**	**(561)**	**(621)**	**(566)**
2006 IRP Resources	Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28	Jan-29	Feb-29	Mar-29	Apr-29	May-29	Jun-29	Jul-29	Aug-29	Sep-29	Oct-29	Nov-29	Dec-29
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Remaining Monthly Surplus/Deficit	**0**	**(213)**	**(214)**	**0**	**(550)**	**(1,789)**	**(2,272)**	**(1,694)**	**(1,444)**	**(150)**	**(310)**	**(329)**	**(210)**	**(213)**	**(214)**	**0**	**(557)**	**(1,821)**	**(2,288)**	**(1,583)**	**(1,487)**	**(214)**	**(273)**	**(218)**
2009 IRP DSM	Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28	Jan-29	Feb-29	Mar-29	Apr-29	May-29	Jun-29	Jul-29	Aug-29	Sep-29	Oct-29	Nov-29	Dec-29
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	128	127	127	127	128	127	127	127	127	127	127	128	127	127	127	127	128	127	127	127	128	127	127	128
Total New DSM Peak Reduction	128	127	127	127	128	438	438	184	127	127	127	128	127	127	127	127	128	438	438	184	128	127	127	128
Remaining Monthly Surplus/Deficit	**0**	**(86)**	**(88)**	**0**	**(422)**	**(1,351)**	**(1,834)**	**(1,510)**	**(1,316)**	**(23)**	**(183)**	**(201)**	**(83)**	**(86)**	**(88)**	**0**	**(429)**	**(1,383)**	**(1,851)**	**(1,400)**	**(1,359)**	**(87)**	**(146)**	**(91)**
2009 IRP Resources	Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28	Jan-29	Feb-29	Mar-29	Apr-29	May-29	Jun-29	Jul-29	Aug-29	Sep-29	Oct-29	Nov-29	Dec-29
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	2	2	0	0	3	10	0	0	0	0	0	1	2	2	0	0	3	10	0	0	0	0	0	1
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2022 Wind (100 MW)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
2024 Large Aero (2 X 100 MW)	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
2025 Gateway West Transmission	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2026 Large Aero (2 X 100 MW)	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
2027 Wind (2 X 200 MW)	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
2028 Large Aero (4 X 100 MW)	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
2029 Large Aero (5 X 100 MW)													500	500	500	500	500	500	500	500	500	500	500	500
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(384)**	**(60)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**