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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S 2013 INTEGRATED RESOURCE PLAN.	**CASE NO. IPC-E-13-15** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission comments as follows on Idaho Power Company's 2013 Integrated Resource Plan ("IRP").

BACKGROUND

On June 28, 2013, Idaho Power Company filed its 2013 IRP. The IRP explains how the Company intends to adequately and reliably serve its electric customers at the lowest system cost over the next 20 years. The Company files an IRP every two years as required by the Commission. *See* Order No. 22299.

The 2013 IRP addresses available supply-side and demand-side resource options, planning period load forecasts, potential resource portfolios, a risk analysis, and includes an action plan that details how the Company intends to implement the IRP. The IRP filing consists of four documents: (1) the 2013 IRP; (2) Appendix A – Sales and Load Forecast; (3) Appendix B – Demand-Side Management 2012 Annual Report; and (4) Appendix C – Technical Appendix.

The Company says it incorporated stakeholder and public input into its IRP by working with the Integrated Resource Plan Advisory Council ("IRPAC"). The IRPAC meetings were open to the public, and the Company says the IRPAC and members of the public significantly contributed to the IRP.

STAFF ANALYSIS

Staff actively participated in the IRPAC and believes the current IRP reflects the Company's continued improvement in incorporating the group's feedback. Idaho Power held 11 IRPAC meetings while preparing the IRP. Many of these were well-attended by non-IRPAC members. Both IRPAC members and non-members were involved in the discussions, several of which were categorized as "spirited." The Company's acceptance of input is evidenced by the IRP's inclusion of a resource portfolio proposed by the Idaho Conservation League and Boise State University that centers on early retirement of the Company's coal-fired facilities. While not all recommendations were incorporated, nor all of the conclusions universally supported, the Company's willingness to discuss sensitive issues represents progress toward developing a robust IRP.

Unlike the past two IRPs, in this IRP the Company analyzed the 20-year planning period in one segment as opposed to two, 10-year segments. Idaho Power previously stated that bifurcating the 20-year planning period prevented resource decisions for the first 10 years from being influenced by more speculative and unproven resource decisions from the second 10-years. 2009 IRP, p. 3. Staff has acknowledged the benefits and risks associated with modeling each period separately, and supports the Company's return to a single, 20-year planning period for this IRP. The IRPAC also endorsed the return to the 20-year planning period, and it is appropriate given Idaho Power's changing circumstances. The Company revisited the 20-year period for this IRP to account for long lead times for new resources and the IRP's role in PUPRA rate setting. 2013 IRP, p. 2. Also, it was unnecessary to divide the 20-year period because lower growth projections, the recent addition of Langley Gulch, and the presumed on-line date of the Boardman to Hemingway ("B2H") transmission line significantly reduce the Company's need for more supply-side resources in the near and long term.

The 2013 IRP's primary goals are to: (1) identify sufficient resources to reliably serve growing energy demands over the 20-year planning period; (2) ensure the selected resource portfolio balances cost, risk, and environmental concerns; (3) give equal and balanced treatment to supply-side resource and demand-side measures; and (4) involve the public in the planning process. 2013 IRP, p. 1. Despite specific issues addressed in these comments, Staff believes the

Company has effectively accomplished these goals while meeting Commission requirements set forth in Order No. 22299.

Load and Resource Balance

This IRP system peak and load forecasts are lower than those in the 2011 IRP. The Company cites several reasons for the declines. Notably, 133 average megawatts (aMW) of load from Hoku Materials and a proposed server farm (denoted as a "Special" customer) have been removed from the prior forecast. Lingering effects of the recession have shown that the 2011 IRP's recovery projections were overly optimistic. Finally, the 2013 IRP projects declining use per customer for the residential class. The result is a more conservative expectation of load growth in the Company's service territory. The Company continues to use 70th percentile water conditions and 70th percentile average load for energy planning, and 90th percentile water conditions and 95th percentile peak-hour load for capacity planning.

The Company expects the population in its service territory will continue to grow, mainly due to net migration from other states. *Id* at p. 48. The IRP projects that the Company will serve 170,000 more customers over the 20-year planning horizon. Customer growth is partially offset by forecasts of declining residential use per customer over the timeframe, prior to any incremental energy efficiency savings. The Company says recent changes in lighting standards and customer response to higher retail prices drive the lower per-customer use for the residential class. The IRP also projects robust sales among the commercial and industrial sectors, and relatively flat load for the irrigation class. In total, average system load is projected to increase by 21 aMW (1.1%) each year through 2032. Peak demand is expected to grow at a compounded rate of 1.4% a year.

The following table reflects the average annual compound growth rates and selected peak loads for the last four IRPs. While the differences between growth rates appear relatively minor, the impact for peak-planning purposes is significant. Between the 2011 and 2013 IRPs, the Company's peak load expectations for 2018 declined by over 400 MW, nearly as much as the Danskin and Bennett Mountain gas peaking units combined. Staff believes the Company's forecasting methods and data are sound. The table illustrates the inherent uncertainty of electric load forecasting, even within the near-term.

Idaho Power Energy and Peak Forecasts By IRP				
IRP	Growth Rate (%)		Peak Load (MW)	
	Energy	Peak	2018	2025
2006	1.9	2.1	4,051	4,689
2009	0.7	1.5	4,003	4,341
2011	1.4	1.8	4,056	4,529
2013	1.1	1.4	3,651	4,033

The Company's use of the 70% planning criteria for energy and 90/95% for peak is consistent with IRPs since 2002. In that time, Staff has generally supported Idaho Power's conservative planning approach. Staff continues to support the 70th percentile load and water conditions for evaluating future energy needs. But Staff recommends that the Company investigate whether it should adjust its peak load planning criteria before the next IRP.

The change in planning criteria arose from the energy crisis of the early 2000's and relying on market transactions to meet peak deficits. Severe spikes in Mid-C prices were a function of a regionally under-built transmission system and market manipulation. In response, entities throughout the Pacific Northwest have taken steps to ensure customers are not exposed to such volatile energy costs. Over 75,000 miles of transmission build-out from 2001 to 2012[1], and enhanced protocols, have increased the grids connectivity and reliability within the Western Electricity Coordinating Council's ("WECC") footprint. From 2003 to 2012, over 11,500 MW of net generation[2] capacity has been added in the Pacific Northwest, primarily consisting of natural gas-fired facilities and wind. The Company's B2H transmission project will improve its access to low cost energy resources in the Northwest via the Mid-C market. As detailed below, the B2H project remains the preferred resource alternative under all the risk scenarios, implying that reliance on the market is less risky in today's environment.

Idaho Power relies less on hydroelectric generation now than in 2002 because it has added more gas-fired generation. While water conditions remain important in meeting customer demand, they are not the resource balance drivers they once were. Intuitively, moving to a less

[1] Source: WECC State of Interconnection 2012 Report.
[2] Net generation takes into consideration plant retirements. Source: Northwest Power and Conservation Council.

restrictive peak planning criteria would result in smaller deficits, and may potentially delay the building of a resource designed to meet a low-probability event. Less restrictive, yet still conservative planning criteria may include a specific planning reserve margin or more probabilistic water and load conditions (80% load and water for peak planning, as an example). Staff believes the Company's current resource position provides an opportunity for the Company to reassess its planning criteria for the upcoming IRP cycle without unduly jeopardizing its obligation to meet customer demands.

The Company has updated its facilities' operating characteristics to reflect additional constraints going forward. Streamflow and management practice trends in the Snake River Basin have been incorporated into the hydrologic modeling, resulting in a more realistic view of hydro availability throughout the planning horizon. The Company also considered the potential generation loss arising from the installation of pollution-control equipment on its coal-fired facilities. In Case No. IPC-E-13-16, Staff addressed the investment decisions regarding coal retrofits. For this IRP, Staff believes the Company has been consistent with the findings from its Coal Unit Environmental Investment Analysis, and that its coal generation is properly reflected in the resource balance for baseline purposes.

The results of the load and resource balance show that the Company has no energy-related deficits throughout the planning period. The IRP shows a capacity deficit beginning in 2016, which steadily increases through the planning horizon. Without more resources, the peak-hour capacity shortfall grows from 126 MW in 2016 to 1,095 MW in 2032. Peak-hour deficits occur exclusively in the summer months when irrigation load coincides with residential and commercial air conditioning load.

Natural Gas and Coal Adder Forecasts

Prior IRPs used a weighted composite natural gas forecast based on several public and private sources. The 2013 IRP relies on the US Energy Information Administration ("EIA") forecast published in the *Annual Energy Outlook 2012* from June 2012. The EIA forecast was used for the Company's coal replacement study, and is the Commission-approved source for gas prices when updating the avoided-cost rates for PURPA projects. Staff supports the consistent use of the EIA forecast for planning purposes, though Staff recommends that the Company use the EIA nominal forecast instead of applying its own escalation factor to the 2010 constant dollar forecast. Staff uses EIA's nominal price forecast to calculate published avoided cost rates for

PURPA projects, and supports it in Case No. IPC-E-13-16 as a more transparent use of EIA's data. It is unclear if the Company applies its escalation factor to capture the effect of lower purchasing power in the future, or some belief that the forecast produces prices that are inherently lower than what can be expected in the future. Either way, Staff believes the EIA nominal forecast more transparently provides a fuel price that indicates what the fundamental forecast predicts prices will be at a given point in time. The difference between the EIA nominal forecast and the Company's escalated values can be as large as 30% or more, meaning the Company may be overstating the fuel cost associated with natural gas facilities. Staff continues to believe it is reasonable for Idaho Power to apply a standard 3% escalation rate to capital and general O&M expenses.

The Company applies a carbon adder to the generation from CO_2-emiting resources, as it has since the mid-90s. The base case scenario of $14.64 per ton beginning in 2018 and escalated at 3% comports with the value used in the Company's coal investment study. The IRPAC vetted and generally supported this carbon adder. Staff believes the range of carbon scenarios (a low of $0 per ton to $35 per ton in 2018 escalated at 9%) is reasonable given the uncertainty surrounding future carbon regulations.

Demand-Side Management

Before analyzing the load and resource balance, the Company adjusts the balance by including demand-side management ("DSM") resources. The Company relies on a Conservation Potential Study or Assessment ("CPA") by a third party consultant to set achievable savings for the IRP planning period. Energy savings from potential programs effectively reduce the resource deficit and alleviate the obligation to add additional supply-side resources.

Conservation Potential Study

Idaho Power commissioned EnerNOC to complete a 20-year CPA to forecast technical, economic and achievable energy efficiency savings. The CPA analyzed the Residential, Commercial, Industrial and Irrigation sectors to ascertain criteria like electric use, market characterization and potential savings. The Company previously completed a CPA in 2009. EnerNOC forecasted 234 aMW of total achievable savings by 2032. The Commercial sector provides the largest achievable potential savings through 2027. The Industrial sector provides the second largest source of savings until 2015, when Residential sector savings become the second largest source. The Irrigation sector provides the least amount of potential savings. Lighting in the Residential (59% of total residential savings) and Commercial (46%) sectors is forecast to provide the largest potential achievable savings by end use in 2017. Most of the Industrial savings are from motors (52%). The study forecasts scientific irrigation practices will comprise most of the Irrigation sector's savings (38%).

The CPA illuminates the large disparity between achievable and economic potential savings in Idaho Power's service territory, which is largely a symptom of program participation rates. While achievable savings over the 20-year period are estimated at 234 aMW, the forecasted economic potential is 438 aMW. Staff recommends that the Company increase its efforts to improve customer participation rates to bridge the disparity between achievable and economic potential savings.

Staff believes the CPA is an appropriate venue to forecast future potential savings. As stated earlier, the Company will use the CPA's forecast and may refine the savings potential that is then incorporated into its IRP load and resource balance. Staff notes the CPA was not included in the IRP filing, and that the IRP failed to address how the Company will acquire the future savings.

Future Savings

The Company refined the CPA's 20-year energy potential savings from 234 aMW to 261 aMW. In the short term (2013 – 2017), the Company projects 69 aMW of achievable energy savings. The Company applies its forecasted future savings to the Load and Resource Balance section of the IRP. Staff has two concerns about the Company's treatment of DSM savings in the IRP. First, the load and resource balance calculation excludes new Residential energy efficiency savings in 2013 and 2014 with no explanation. Second, there is inadequate discussion of the Company's future energy efficiency acquisition plans. The Company includes forecasted energy savings in its load and resource balance, but fails to adequately describe *how* the savings are to be acquired. Considering that the DSM alternate costs for energy efficiency have decreased by almost 50% from the 2011 IRP, and the Company's total energy savings have decreased over the past two years, it is not clear in the IRP how the Company plans to acquire forecasted energy efficiency savings. Preliminary cost-effectiveness analysis from the September 18, 2013 Energy Efficiency Advisory Group ("EEAG") indicates that over half of the Residential energy efficiency programs are not cost-effective due to the 2013 alternate cost used in the cost-effectiveness calculation. The IRP Action Plan does not describe current problems or how they might be resolved to acquire the energy efficiency resources in the future.

Staff acknowledges that the EEAG is the Company's forum to discuss future DSM acquisition. But the IRP is the centralized document that matches future need with resources. As such, the IRP should discuss future energy efficiency acquisition. Staff recommends the Company provide greater detail of future energy efficiency acquisition in the IRP's Action Plan section.

Dynamic Pricing Programs

The Company does not consider expanded dynamic pricing programs in its IRP. Dynamic pricing can take many forms, including time of use and critical peak pricing. Though dynamic pricing is not DSM in the traditional sense, Staff believes that large scale dynamic pricing programs can significantly impact the Company's peak loads. Idaho Power currently has mandatory time of use rates for large industrial customers (Schedule 19). But it has not conducted an impact evaluation of the rate design since 2007 (the rate design went into effect in 2004). The Company also has a voluntary time of use program for residential customers that has provided inconclusive results regarding peak load shaving capability. Staff recommends that the Company investigate dynamic pricing options, enrollment strategies, and potential savings for inclusion in its the next IRP. The findings would inform the Company and IRPAC as to whether pricing structures can potentially reduce future peak loads.

Resource Alternatives Analysis

In response to comments from the IRPAC, the Company analyzed initial resource alternatives before developing its portfolio. The goal of this approach was to isolate the impacts of a particular resource addition rather than the combination of resources developed in the Company's portfolios. Eight resources were chosen for the analysis, and scaled to meet 200 MW of on-peak capacity at a 90% exceedance value (200 MW 9 times out of 10). The eight resources and the associated costs are included as Attachment A to Staff's comments. Aside from the upfront capital cost, particular resources, such as solar, compare unfavorably due to the additional nameplate capacity needed to achieve the 200 MW evaluation criteria.

As the Company points out, the treatment of distributed solar Photovoltaics ("PV") was a divisive point of discussion throughout the IRP planning process. For both utility scale and distributed PV, the Company relied on cost and operating characteristics from the February 2012 *Cost and Performance Data for Power Generation Report* published by the National Renewable Energy Laboratory ("NREL"). The NREL report served as the foundation for all supply-side resource inputs. Unlike other generation resources, solar was modeled with a slight decrease in capital cost over the planning period. Solar costs have been on a downward trend for a number of years, and it is thought that technological breakthroughs and increased production could halve the price of installations in the next 15 years.[3] The Company's price assumptions are more modest, and may not account for potential efficiency gains from new PV technologies.

The IRP includes the full cost of distributed PV, including customer costs. Several IRPAC members argued that as a utility planning document, the IRP should only concern itself with utility costs, thereby representing distributed PV as virtually costless. Staff concurs that the IRP should analyze only utility costs. That said, arguments that customer-owned PV should be modeled as costless ignore all entry barriers, and result in spurious conclusions.[4] Even with the cost of distributed PV installations becoming more competitive, Staff believes distributed PV cannot be considered a plausible resource alternative until some consensus can be reached on appropriate pricing assumptions that balance the Company and customers' perspectives. Staff recommends that the Company investigate whether incentive programs could realistically generate enough interest in expanding distributed PV installations in sufficient capacity (10 MW and above) to warrant including distributed PV as an alternative resource. The analysis would provide a good foundation for discussion in the next IRP cycle, and would result in a representative price in alternative analysis.

The Company conducted further risk analysis on the eight resources to test for sensitivities to changes in natural gas prices, carbon adders and water conditions. The rank order of the resources did not change under any of the risk scenarios. After reviewing the table in Attachment A, it is not surprising that the ranking remained unchanged under the various risk scenarios. The primary driver in total cost differences between the resources is the capital, or fixed costs, which would be unchanged under the different risk scenarios. The change in total cost is attributed to changes in variable cost, which are calculated for the existing resources plus

[3] Source: Distributed Generation System Characteristics and Costs in the Buildings Sector, EIA, August 2013.
[4] By that logic, the Company should spend no resources and acquire all distributed solar it can. It currently does so through the net metering tariff, which accounts for approximately 3 MW of generation.

the additional resource being analyzed. The magnitude of the change in system variable cost for each resource alternative is not significant enough to overcome the disparity in fixed costs.

Portfolio Design and Selection

The results of the alternative resource analysis served as the basis for designing resource portfolios to meet the Company's forecasted deficits over the next 20 years. Nine resource portfolios were analyzed, and generally fell into three main categories:

1. B2H resource portfolios (2), designed around an on-line date of 2018;
2. Alternative to B2H portfolios (3), which exclude B2H as a resource; and
3. Coal alternative portfolios (4), which explore the partial or full retirement of the Company's coal-fired facilities.

Each portfolio was designed to meet the Company's peak-hour needs accounting for existing and committed resources and energy efficiency. The net present value ("NPV") of each portfolio was used as a preliminary ranking method. The results are included as Attachment B to Staff's comments. The Company then performed a stochastic analysis to test the robustness of each portfolio under varying load, gas, carbon and hydrologic scenarios.

Generally speaking, the portfolios that contain B2H and ongoing coal-fired operations performed better than portfolios without B2H or retired coal facilities. The two lowest cost portfolios, both with B2H and one with demand response (Portfolio 2) and one with demand response and a Simple Cycle Combustion Turbine ("SCCT") addition in 2029 (Portfolio 1), significantly outperformed the alternatives from a least cost and least risk standpoint. The NPVs for these two portfolios are nearly identical; Portfolio 2 is less than 1% cheaper than Portfolio 1 under planning conditions. The primary difference between the two is the fixed cost, which tempers Staff's concern regarding the Company's adjustment to the EIA natural gas price forecast. Staff also notes that these portfolios are identical until 2029, confirming that the demand response/B2H combination is the preferred near- and mid-term option.

Though the portfolios that assess early retirement of coal plants perform poorly in terms of NPV, Staff believes it is beneficial to include them in this analysis. The use of carbon adders is an appropriate method for capturing the additional cost of environmental regulations. But it does not effectively convey the impact that stringent regulation may have if the plants are forced to shut down entirely. The analysis shows that early retirement of coal-fired facilities could expose ratepayers to increases 35% greater than the preferred alternative over the next 20 years.

Staff expects the Company to continue to include a similar type of analysis in future IRPs as emissions costs and regulations evolve in the coming years.

Staff noted in its previous IRP comments that the Company's analysis fails to quantify the risk associated with transmission siting and escalating capital cost. IPC-E-11-11, Staff Comments, p. 13. Staff is concerned that all portfolios containing B2H assumed a specific in-service date, and no analysis was conducted to address the potential delay in the projected completion. The conclusion of the environmental review and routing process are mostly beyond the Company's control. The Company's demand response programs may be able to meet peak deficiencies for 2018 and 2019. But after that, deficits grow in duration beyond what current demand response programs can handle. Staff recommends the Company provide an alternative action plan that would result from a 2 to 5 year delay in the construction of B2H as part of its next IRP update.

Preferred Resource Portfolio and Action Plan

Based on the Company's analysis, the preferred portfolio comprised of demand response and B2H in 2018 (Portfolio 2) performed best in terms of least-cost and least-risk. Under virtually all scenarios, Portfolio 2 proved to be less costly than alternatives that did not include B2H. Staff believes this result is well-supported, with the reservation that the B2H timeline is not certain. Additionally, Staff notes that none of the analysis made any assumptions about the completion or impact of the Gateway transmission expansion of which the Company is a part. Staff recommends that the Company include a broader discussion and analysis of the Gateway transmission project in its IRP update.

The Company's Action Plan is shown below. The specified actions are representative of the IRP analysis and, besides the lack of detail on additional energy efficiency acquisition, provide an adequate blueprint given the information at this time. Although the IRP Action Plan is not intended to bind Company decisions, Staff expects the Company to keep the Commission well-informed on the progress made toward achieving the identified goals.

Table 10.1 Portfolio 2 action plan

Year	Resource	Action
2013–2018	Boardman to Hemingway	Ongoing permitting, planning studies, and regulatory filings.
2013–	Gateway West	Ongoing permitting, planning studies, and regulatory filings.
2013	North Valmy Unit 1	Commit to the installation of dry sorbent injection emission-control technology.
2013	Jim Bridger Units 3 and 4	Commit to the installation of selective catalytic reduction emission-control technology.
2016–2017	Demand response	Have demand response capacity available to satisfy deficiencies up to approximately 150 MW.
2018	Boardman to Hemingway	Transmission line complete and in service.
2019	Shoshone Falls	Shoshone Falls upgrade complete and in service.
2019	Jim Bridger Unit 2	Commit to the installation of selective catalytic reduction emission-control technology.
2020	Jim Bridger Unit 1	Commit to the installation of selective catalytic reduction emission-control technology.
2020	Boardman	Coal-fired operations at the Boardman plant are scheduled to end by year-end 2020.
2024–2032	Demand response	Have demand response capacity available to satisfy deficiencies in 50-MW increments up to approximately 370 MW in 2031.

STAFF RECOMMENDATIONS

After reviewing Idaho Power Company's 2013 IRP, Staff believes that the Company performed extensive analyses, gave reasonably equal consideration of supply- and demand-side resources, and provided acceptable opportunities for public input, resulting in an IRP that satisfies the requirements set forth in Commission Order Nos. 25260 and 22299. Staff, therefore, recommends that the Commission acknowledge the Company's 2013 IRP.

Respectfully submitted this 5th day of November 2013.

Karl T. Klein
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Table 7.1 Resource alternatives to achieve 200 MW of peak-hour contribution in 2018 (NPV years 2013–2022, 2013 dollars, 000s)

Resource Alternative	Peak-Hour Capacity (90% exceedance)	2018 Peak-Hour Deficit Target (MW)	Installed Nameplate Needed to Meet 200 MW Peak	Variable Costs (Aurora)	RECs Sold (reflected in variable costs)	Fixed Costs (plant, transmission, fixed O&M, & rate of return)	New Natural Gas Pipeline Capacity Charge	Total	Lowest Cost Rank	Lowest Cost Relative Difference
1—Northwest transmission	100%	(200)	200	$2,674,610	N/A	$33,039	–	$2,707,650	1	$0
2—SCCT	95%	(200)	211	$2,677,067	N/A	$79,331	$7,152	$2,763,549	2	$55,900
3—CCCT	95%	(200)	211	$2,646,794	N/A	$134,786	$38,377	$2,819,957	3	$112,308
4—CHP	95%	(200)	211	$2,644,909	$5,964	$192,212	$34,461	$2,871,582	4	$163,932
5—Pumped storage fueled by LL wind	100%	(200)	200	$2,677,703	$10,332	$311,842	–	$2,989,545	5	$281,895
6—Canal drop hydroelectric	67%	(200)	299	$2,513,007	$21,104	$603,920	–	$3,116,927	6	$409,277
7—Utility solar PV	32%	(200)	625	$2,514,873	$17,589	$882,286	–	$3,397,159	7	$689,510
8—Distributed solar PV	39%	(200)	513	$2,542,702	$14,550	$1,338,597	–	$3,881,298	8	$1,173,649

Note: Variable costs reflect the existing system plus the resource alternative. Fixed costs are representative of the resource alternative only.

Source: 2013 IRP, p. 98

Table 9.2 2013 IRP portfolios, NPV years 2013–2032 (2013 dollars, 000s)

	Variable Costs	Fixed Costs				Summary		
Portfolio (1)	Operating[1] (Aurora) (2)	New Resources[2] (3)	New Natural Gas Pipeline Capacity Charge (4)	Demand Response (5)	Total (6) (3)+(4)+(5)	Total Portfolio Costs (7) (2)+(6)	Lowest Cost Rank (8)	Lowest Cost Relative Difference (9)
2—Boardman to Hemingway plus Demand Response	$4,987,003	$185,028	$0	$48,547	$233,575	$5,220,578	1	$0
1—Boardman to Hemingway plus Demand Response and an SCCT	$4,987,143	$221,699	$2,300	$34,818	$258,817	$5,245,960	2	$25,382
3—Demand Response plus a CCCT and an SCCT	$4,940,835	$351,762	$80,973	$105,933	$538,668	$5,479,503	3	$258,925
4—Demand Response plus Two CCCTs	$4,872,870	$638,016	$166,043	$52,744	$856,803	$5,729,673	4	$509,095
8—North Valmy Closure, replaced with Demand Response, Boardman to Hemingway, and a CCCT	$5,056,695	$598,447	$38,902	$73,927	$711,276	$5,767,971	5	$547,394
5—Demand Response plus Two Consecutive CCCTs	$4,843,988	$796,666	$211,320	$35,067	$1,043,052	$5,887,040	6	$666,463
9—North Valmy Closure, Boardman to Hemingway Alternative	$4,991,277	$744,041	$139,722	$127,677	$1,011,439	$6,002,716	7	$782,138
6—ICL–BSU	$5,688,123	$650,693	$336,164	$57,771	$1,044,628	$6,732,751	8	$1,512,173
7—Coal to Natural Gas Conversion plus Boardman to Hemingway and Demand Response	$5,789,525	$654,534	$516,133	$45,965	$1,216,632	$7,006,156	9	$1,785,578

[1] Variable operating costs reflect the existing system with coal plant shutdowns (when applicable) plus the new portfolio resources, REC sales, and carbon adder.

[2] New plant capital, new plant transmission, stranded asset value, environmental compliance upgrade (when applicable), accelerated recovery of existing coal plant investment, and decommissioning coal asset.

Source: 2013 IRP, p. 98

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 5TH DAY OF NOVEMBER 2013, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-13-15, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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