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June 13, 2012

VIA HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
Boise, Idaho 83702

Re: Case No. IPC-E-12-14
Langley Gulch Rate Case – Idaho Power's Reply Comments

Dear Ms. Jewell:

Enclosed for filing please find an original and seven (7) copies of Idaho Power Company's Reply Comments in the above matter.

Very truly yours,

Lisa D. Nordstrom

Lisa D. Nordstrom

LDN:kkt
Enclosures

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND ITS RATE BASE TO RECOVER ITS INVESTMENT IN THE LANGLEY GULCH POWER PLANT.	)	CASE NO. IPC-E-12-14 IDAHO POWER COMPANY'S REPLY COMMENTS

Idaho Power Company ("Idaho Power" or "Company") respectfully submits the following Reply Comments in response to the Notice of Modified Procedure set forth in Order No. 32523 and Comments filed on May 30, 2012.

I. PROCEDURAL BACKGROUND

In August 2009, the Idaho Public Utilities Commission ("Commission") issued Order No. 30892 granting Idaho Power a Certificate of Public Convenience and Necessity ("CPCN") authorizing Idaho Power to construct and operate the Langley Gulch power plant ("Langley" or "project"). Certificate No. 486. The Order also provided the Company with "regulatory assurance" pursuant to *Idaho Code* § 61-541 that the Company would receive rate base treatment for its Langley investment "in the

amount of $396,618,473 at such time as the plant is placed in commercial operation." Order No. 30892 at 46.

On March 2, 2012, Idaho Power applied in this docket for authority to increase its rate base and rates upon completion of Langley, a 330 megawatt ("MW") natural gas-fired combined-cycle combustion turbine near New Plymouth, Idaho. Idaho Power proposed that $390,942,172 of rate base additions and a resulting overall rate increase of 7.18 percent become effective July 1, 2012.

On March 21, 2012, the Commission issued its Notice of Application and set a deadline for intervention. Order No. 32488. Petitions to intervene were filed by the Industrial Customers of Idaho Power ("ICIP"), Micron Technology, and the Idaho Irrigation Pumpers Association ("IIPA"). These petitions were subsequently granted in Order No. 32503. The Commission's Notice of Application directed the parties to meet informally to discuss the processing and scheduling of this case, which they did at an informal scheduling conference held on April 10, 2012. "The parties agreed that this case could be processed via Modified Procedure" and the proposed schedule was later approved by the Commission. Order No. 32523 at 1.

On May 30, 2012, Commission Staff ("Staff"), ICIP, IIPA, and the Snake River Alliance ("SRA") filed Comments regarding Idaho Power's Application. In the paragraphs that follow, Idaho Power will respond to a number of issues raised by these parties in their Comments.

II. DISCUSSION

A. The Company's Proposed Recovery of its Langley to Wagner Transmission Line Upgrade Is Reasonable.

The Staff recommends that the Commission disallow rate recovery in this proceeding on approximately $1,197,938 of incremental rate base related to specific

aspects of the construction configuration of the Langley to Wagner Tap 138 kilovolt ("kV") transmission line that was necessary to effectively and reliably integrate Langley into the Company's electrical system. The Staff contends that because the Company plans to operate the transmission line at 138 kV in the near-term, the incremental cost of constructing the Langley to Wagner Tap transmission line to 230 kV should be excluded from the current request and placed in the plant held for future use account. Staff Comments at 5, 10-11. The Company disagrees with the Staff's recommendation with regard to the regulatory treatment of this incremental investment. Idaho Power believes that its decision to construct the Langley to Wagner Tap transmission line to 230 kV specifications was the most economical construction configuration based upon a long-term view of the system operations. The Company believes that it is in the best interest of its customers to take a long-term view when making large capital investments, especially large transmission investments.

At its planned 138 kV operating capacity, the Langley to Wagner Tap transmission line will be fully utilized to integrate Langley into the Company's electric system. If the line would have been constructed to only 138 kV specifications, there would have been no additional capacity available on the line to accommodate additional generation resources or transmission interconnections located in the western portion of the Company's system. For this reason, the Company presented a 230 kV Langley to Wagner Tap line in the Western Treasure Valley Electrical Plan, which was supported by the Western Treasure Valley Electrical Plan Community Advisory Committee. Under a 138 kV scenario, any resource additions in that area of the system would require the Company to remove the 138 kV line and reconstruct a 230 kV line at a cost of

approximately 11 million in today's dollars. Even if one were to assume that the resource addition or transmission interconnection would not occur for 10 more years, the present value of the avoided construction cost would still be more than $4 million (using an 8 percent discount rate) or more than triple the incremental cost of the upgrade. Further, the Company would be required to request from the Bureau of Land Management ("BLM") siting authority to widen the BLM right-of-way and reconstruct a 230 kV line in the existing location, a process that is becoming increasingly more difficult and costly. The necessity to route the line across federal land and through Slickspot Peppergrass, a native plant species found only in southwest Idaho and listed by the United States Fish and Wildlife Service ("USFWS") as endangered under the Endangered Species Act, created considerable permitting and regulatory risk with both the BLM and USFWS. At the time of permitting, critical habitat for the species had not yet been designated by the USFWS, but was being developed.[1] Given the heightened conservation focus both federal agencies had on the species, and the potential significant risk the Company would encounter by disturbing more habitat in the future, especially if that habitat was determined to be critical habitat as defined by the Endangered Species Act, the Company determined that it would be prudent to construct the line at 230 kV. This permitting and regulatory issue presents an additional cost risk that was not included in the $11 million avoided cost estimate.

Other risks and costs associated with rebuilding the line would include obtaining new county permits and obtaining wider easements, both of which would have negative

[1] Subsequent to the line being built, critical habitat has been designated by the USFWS. The line intersects one of four management units designated as critical habitat for the species. Any future project will have to show that it will not adversely affect critical habitat. A future rebuild of the line from 138 to 230 kV or the addition of a second line would likely adversely affect critical habitat.

impacts to customers whose property would be disrupted a second time, with the potential of a premium payment for the right-of-way. During the reconstruction period of approximately six months, the reliability of Langley would be reduced as the plant would only be connected to the Ontario-Caldwell 230 kV line. In addition, the Caldwell area reliability would be negatively impacted due to reduction in load serving 230 kV to 138 kV transformation capacity.

Idaho Power is sensitive to the impact that incremental investments can have on customer rates. However, the Company believes that its decision to incur the incremental cost of approximately $1.2 million to build the Langley to Wagner transmission line to 230 kV specifications will serve the best interests of customers in the long-term. The Commission's approval of this incremental amount would send a clear message that it is supportive of the Company's efforts to minimize costs for customers in the long-term through an effective and efficient transmission planning process.

This approach is gaining support in other jurisdictions. While Oregon Governor Kitzhaber's proposed 10-Year Energy Action Plan recognizes that current regulatory practices that allow utility cost recovery only for those facilities that will be deemed immediately "used and useful" to customers discourages efficient long-term resource planning, his draft Plan dated June 5, 2012, recommends the Public Utility Commission of Oregon revise its prudence standards to allow for recovery of costs for the upsizing of facilities that are intended to serve long-term growth in demand. Draft 10-Year Energy Action Plan at 27.[2] Such an approach is consistent with the 2012 Idaho Energy Plan's policy adopted by the Idaho Legislature "to encourage a stable, robust, reliable

[2] Found at http://oregon.gov/energy/AnalyticsReports/Ten_Year_Energy_Action_Plan.pdf.

transmission system in order to provide reliable low-cost energy to Idaho consumers and facilitate renewable generation." 2012 Idaho Energy Plan Policy No. 5 at 120.

B. Idaho Power's Request For Proposal ("RFP") Team Expenses Were A Necessary Business Investment That Should Be Recovered in Base Rates.

The Staff recommends that the Commission disallow rate recovery of $251,894 in employee payroll and benefits costs incorrectly identified as costs associated with the development of the Company's benchmark resource proposal. Staff Comments at 5, 10. Staff correctly identified the $251,894 as "RFP team expenses." *Id.* However, the Company believes there was a misunderstanding related to the categorization of the costs. The RFP team expenses were not associated with the development of the Company's benchmark resource proposal; the RFP team expenses were costs of the team that evaluated *all* RFP responses. All of the costs were labor and related expenses for the eight person evaluation team. The Commission should find that these costs are necessary costs incurred in the course of a project of this magnitude and therefore are appropriately included for recovery from customers.

C. IIPA's Proposed Power Supply Methodology Would Inaccurately Reflect Idaho Power's Actual Expenses.

IIPA poses the question: "Is Valmy used and useful?" IIPA Comments at 7. IIPA arrives at this question by presenting the results of an AURORA power supply expense modeling analysis that it requested be performed by the Company during the discovery phase of this case. The analysis presented by IIPA in its Comments was one of seven separate AURORA simulations that the Company prepared at the request of IIPA using several variations of gas prices and load inputs. The analysis results that IIPA uses to support its contention that the Valmy power plant ("Valmy") may not be

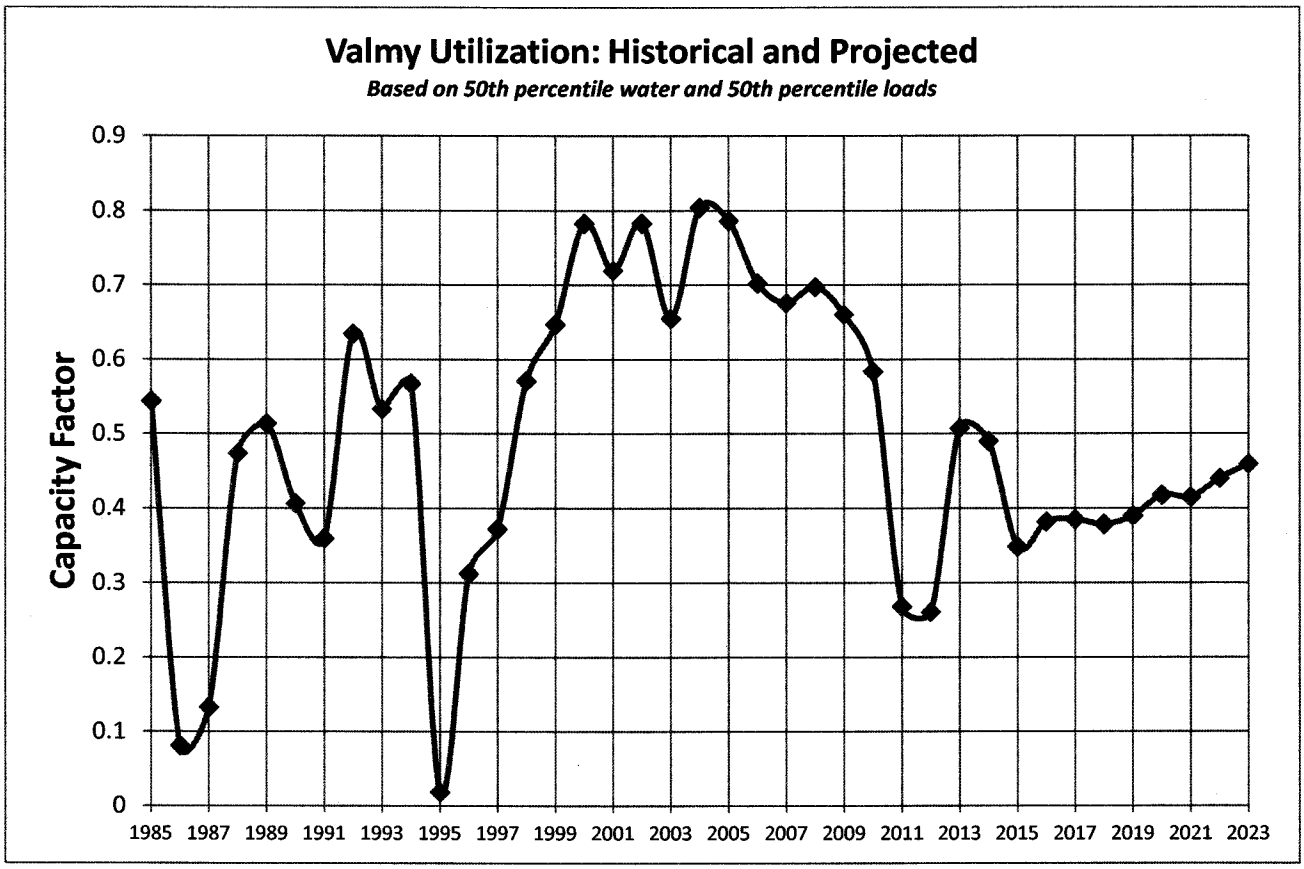
used and useful are based on a modeling scenario that replaced the current Commission-approved gas price inputs with "today's gas prices," while holding all other modeling inputs consistent with the Company's study used to produce the net power supply expenses ("NPSE") filed in this case. Not surprisingly, changing the fuel cost for only one generation resource type (gas) changed the economic dispatch of the Company's generation resource fleet.

IIPA presents the results of the modified analysis first to identify what it believes to be an "absurd[ity]" about the Company's proposal, which is to modify the Company's currently approved NPSE to include the additional generation of Langley. *Id.* at 5. However, IIPA then goes on to utilize the results of the study that it earlier characterized as an "absurdity" to conclude that Valmy is not used and useful by comparing the currently approved NPSE to actual Valmy output from April 2011 through March 2012. IIPA Comments at 5. This conclusion was drawn after the IIPA acknowledged that there are "other changes since 2010 that are well recognized, but not addressed in this model . . . ." *Id.* at 7. While the Company agrees that the IIPA-requested AURORA analysis that replaced the current Commission-approved gas price inputs with "today's gas prices" is flawed considering the lack of comprehensive inputs, Idaho Power does not agree that a separate investigation into the need for Valmy is justified by the analysis results.

The integrated resource planning process is the proper forum to address resource need. The Company's Integrated Resource Plan ("IRP") process includes a comprehensive analysis that looks at future resource needs and examines the economics of Idaho Power's existing resources and potential new resources to develop

a least cost and least risk portfolio of resources to meet future loads. Aside from the problems associated with updating a single fuel input in the NPSE modeling process, IIPA incorrectly draws conclusions regarding resource need based upon an analysis that applied normalized water and weather conditions. The Company's approach to resource planning, which has been accepted by the Commission in past IRP cycles, is to determine resource need based upon lower than normal stream flows and higher than normal load conditions represented by 70th percentile water and 70th percentile load conditions for average monthly load/energy (average megawatts) and 90th percentile for water and 95th percentile for load for peak-hour capacity (MW). This approach ensures that Idaho Power has adequate generation resources to serve loads in the majority of water and load conditions. IIPA is basing its conclusions regarding need on a scenario that applies average conditions. In other words, IIPA has proposed an analytical framework that would determine resource need based upon the assumption that Idaho Power should plan for the ability to serve its customer loads during approximately half of the range of possible conditions.

While the Company does not believe that it is prudent to determine resource need based upon normal water and load conditions, Idaho Power has prepared an analysis that demonstrates that, even under 50th percentile water and 50th percentile loads, Valmy is expected to continue to be used and useful into the future. The following chart presents the historical annual capacity factor of Valmy and the expected capacity factor of the plant as measured in average capacity factor based on 50th percentile water and 50th percentile loads:



As can be seen from the chart, the annual utilization of Valmy into the future under a 50th percentile water and 50th percentile load scenario is not expected to differ dramatically from its past operations. The future plant capacity factor results presented in the chart are based on an AURORA modeling scenario that applied updated coal and gas price inputs (the Northwest Power and Conservation Council's current gas forecast), the Company's current load forecast, and an updated Public Utility Regulatory Policies Act of 1978 ("PURPA") generation forecast under IIPA's normalized scenario. While the Company is not proposing this method be used for resource planning, it represents a more reasonable analysis for assessing the need for Valmy into the future as compared to that presented by IIPA. Valmy's capacity factor is even higher when the IRP 70th percentile water and 70th percentile load criteria is used.

While the annual capacity factor of each of the Company's plants is important to determine how much energy each plant will generate, it is critical to note that Idaho Power's customer demands require the collective summertime peak capacity that each of its plants provides. The planning criteria for peak-hour load conditions is a 90th percentile water and 95th percentile load scenario. The peak-hour analysis is coupled with Idaho Power's ability to import additional energy on its transmission system, which is typically limited during peak load periods. Because of the more stringent load planning criteria, Idaho Power's 2011 IRP assumes that Valmy is available and at full capacity during the peak summer months regardless of how much energy the plant produces on an annual basis.

The method proposed in the Company's Application for determining the impact that Langley is expected to have on NPSE is the most appropriate method for ratemaking purposes. The Commission Staff in its Comments likewise agrees that the Company correctly determined the change in NPSE associated with the addition of Langley. Staff Comments at 14. The Company chose to update its currently approved NPSE to reflect the annual generation for Langley in order to avoid unduly expanding the issues in this case beyond the issue of Langley. The Commission has already examined and approved all of the inputs to determine the current base level NPSE and the Company does not believe it is appropriate to ask the Commission to reexamine those inputs as part of this case.

D. Idaho Power Exercised Proper Managerial Oversight of the Langley Project.

1. No "Regulatory Preapproval Failure" Exists.

Public convenience and necessity required the construction of Langley. In Case No. IPC-E-09-03, the Commission found that "Idaho Power has satisfied the statutory

requirements of *Idaho Code* § 61-541 and has regulatory assurance by the Commission of receiving rate base treatment of the Company's capital investment in Langley Gulch Power Plant and related facilities in the amount of $396,618,473 at such time as the plant is placed in commercial operation." Order No. 30892 at 46. The Commission recognized that the Company's Commitment Estimate was comprised of signed contracts and estimated costs and were persuaded by Staff's "soft-cap" approach of separating those amounts that were known with greater certainty and competitively procured from amounts based on uncertain estimates and contingencies as the basis for the development of the preapproved $396,618,473. This preapproval amount, however, was not an absolute "not to exceed" amount or hard cap. It is *this* proceeding that provides the Company the opportunity to justify any costs above the Commitment Estimate as prudent and present the reasonableness of additional costs:

> Recognizing that the Company's Commitment Estimate is comprised of signed contracts and estimated costs, we are persuaded that Staff's approach to separating costs that are known with greater certainty and competitively procured from amounts that are based on more uncertain estimates and contingencies to be a reasonable method to follow in considering applications under *Idaho Code* § 61-541. Adopting Staff's methodology we find it reasonable to provide the Company with assurance and preapproval under *Idaho Code* § 61-541 for the amount of $396,618,473. Staff Revised Confidential Exhibit 109. The Commission declines to adopt the Staff's recommendation to establish an absolute "not to exceed" amount or hard cap.
>
> *Id.* at 39.

ICIP's Comments are particularly critical of the Commission's commitment in Case No. IPC-E-09-03 to provide rate base treatment for the Company's capital investment in Langley and related facilities in the amount of $396,618,473 at such time

as the plant is placed in commercial operation. *Id.* at 46. ICIP believes that "Idaho Power had no incentive to actively and continuously assess the prudence and timing of this plant because it was virtually guaranteed rate base treatment of the preapproved amount." ICIP Comments at 4. ICIP is mistaken in this belief.

The preapproved rate base treatment was necessary to facilitate the financing of Langley, which could not be internally generated given the state of the capital markets in 2009 and the additional $220 to $295 million of annual infrastructure investments Idaho Power anticipated between 2009 and 2011. Smith, Tr. at 678 and 681, Case No. IPC-E-09-03. The Commission's ratemaking assurances did not absolve Idaho Power of exercising managerial oversight over the project. To the contrary, the Commission made clear that Idaho Power must actively manage construction as a condition of receiving the right to build Langley with ratemaking assurance:

> In consideration of the ratemaking assurance granted pursuant to *Idaho Code* § 61-541, IT IS FURTHER ORDERED as a condition of Certificate No. 486 (*Idaho Code* § 61-528) and the Company (or owner's representative) is hereby directed to submit quarterly progress reports to the Commission describing the status of the Langley Gulch Power Plant in reasonable detail, which shall include information showing actual progress against the Project schedule, estimates of cost to complete and changes to its construction schedule and any other notations of importance to Commission understanding of deviations or adjustments to the project schedule initiated between quarterly reports. The monthly reports shall include a budget update showing total amount expended and billed to date and remaining contract dollars.
>
> Order No. 30892 at 46-47.

As described in greater detail in the sections that follow, Langley is still needed to serve load, promote system reliability, and take advantage of low gas prices to generate off-

system sales to offset power supply expenses. Despite ICIP's claims to the contrary, no "regulatory pre-approval failure" exists. ICIP Comments at 2-4.

2. Exceptional Management Oversight Led to Costs Below the Original Project Estimate.

Historically, the Company has had a good track record of bringing projects in at or below cost estimates. The Langley project is no different. Although preapproval of $396,618,473 of investment in rate base was received in the Company's request in Case No. IPC-E-09-03, the prudency and reasonableness of additional project costs, as requested in this case, are best determined when reviewed with entire project costs. Staff agreed, noting:

> First, because the pre-approved Commitment Estimate is for the cost of the entire project, any review of budget-to-actual expenditures required an analysis of the total project costs. The Company has projected that the total project investment will be $401,416,574, thereby exceeding the Commission-approved Commitment Estimate by approximately $4.8 million. Staff reviewed the Company's budget spending performance and the prudency of expenditures for the total project, not just the amount the Company is seeking in this case. Secondly, Staff reviewed estimates for spending through the end of the project. This was to ensure that the total project expenses were accurate and that evaluation of budget performance was reasonable and realistic. Third, Staff reviewed the certainty of estimates used to project total spending through June 30, 2012. This was done to ensure that the amount of capital expenditure sought in this case would be accurate so that ratepayers would not be compensating the Company for expenses not realized during the test period.
>
> Staff Comments at 4.

"As is expected in a project of this magnitude," the actual costs for the Langley project were higher than expected in some individual cost categories and lower than estimated in other cost categories. Staff Comments at 4. The Company's total project

investment projection of $401,416,574 is approximately $4.8 million, or 1.2 percent, above the preapproved amount (the soft cap). However, the total project investment is $26 million, or 6.1 percent, less than the Company's originally filed Commitment Estimate and approximately $120 million, or 23.2 percent, less than that of the next closest combined-cycle project identified through the RFP process. Idaho Power's exceptional management oversight of Langley's construction results in an under budget project that will be commercially operational in time to reliably meet Idaho Power customers' summer peak needs.

E. <u>Active Reassessment of the Need for Langley</u>.

After the Commission approved the issuance of Certificate No. 486 in Order No. 30892, Idaho Power continued to actively assess and reassess the need for Langley as it was being constructed. Company management regularly reviewed updated load and economic forecasts, created both internally and externally. Although management could not know with accuracy when loads would recover, most economic forecasts indicated that the economic downturn was not permanent and this long-lead generation resource would be needed to serve load on a transmission-constrained system. Considerable uncertainty remained about the timing and ability to construct Boardman to Hemingway and Gateway West transmission. Although PURPA developers were seeking contracts to sell energy to Idaho Power, the Company did not know when the developers would ask for contracts, if the PURPA projects would come online timely, and how much power those largely intermittent resources would generate at times of peak load. Other uncertainties informed Idaho Power's decision to continue Langley's construction, including the potential for: (1) large commercial/industrial requests for

service; (2) transmission constraints and restrictions on firm import capability; (3) integration capability for intermittent generation; (4) $C0_2$ carbon legislation; (5) Snake River flow realignment and loss of summer hydro generation due to biological needs of fish on a federally regulated Columbia River system; (6) operating reserve margins; (7) operational limitations of the Company's natural gas-fired peaker plants; (8) lack of hydro generation capacity during persistent below average-water conditions such as experienced for all but one year during the 2000-2010 period; and (9) market volatility.

1. A Review of the Project's Financial Forecast.

Idaho Power was also cognizant that the bulk of the Commission-preapproved $396 million was irrevocably incurred into the project shortly after Order No. 30892 was issued on September 1, 2009. By December 31, 2010, Idaho Power had invested or was contractually obligated to spend approximately $188 million for the steam turbine, gas turbine, heat recovery steam generator, and land and water rights. The Engineering and Procurement Contract also called for a cancellation charge to be paid in the amount of work completed plus a 15 percent markup. Because the costs of these long-lead items are front-loaded, the economic cost of cancelling the Langley project would have left customers with significant expense and only a partially built resource in an uncertain economic and system planning landscape. The Company's actions were and are continually informed by its statutory obligation to provide and maintain adequate, reliable, and efficient electric service. *Idaho Code* § 61-302. Simply put, the asymmetrical risks of delaying a needed resource far exceeded the financial consequences of potentially bringing a plant online early.

2. An Evaluation of Projected Loads.

ICIP criticizes Idaho Power's continued decision to move forward with Langley due to declining loads. ICIP asserts that since Order No. 30892 was issued authorizing rate base treatment for Langley and its associated facilities, Idaho Power's general business loads "have declined by 810,000 MWh or by 5.6 percent." ICIP Comments at 4. ICIP continues by alleging that the Order was signed with the assumption of "robust load growth" which provided Idaho Power with no incentive to assess the prudence of Langley. *Id.* ICIP misstates Idaho Power's general business loads, the Company's load forecast assumptions at the time, and the internal forecasts that led management to continue with the project.

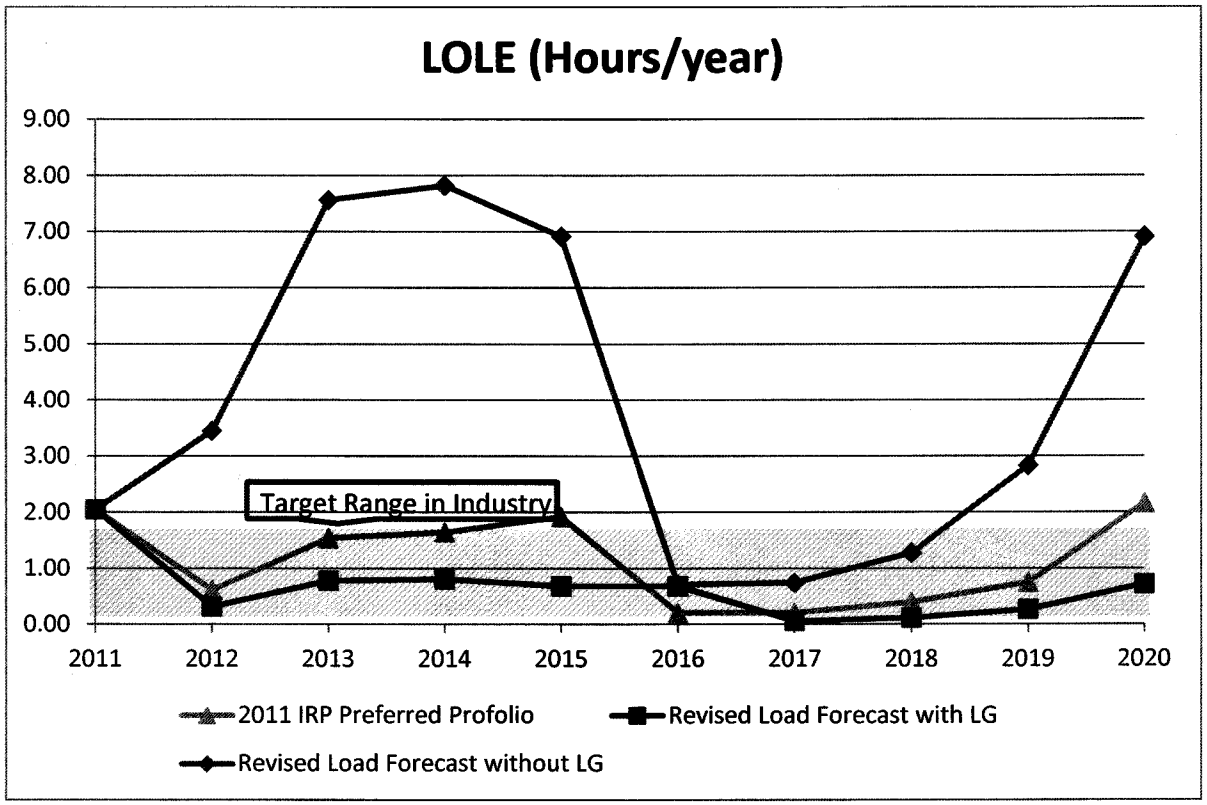
Order No. 30892 authorizing rate base treatment for the Company's capital investment in Langley and associated facilities was issued on September 1, 2009. In 2009, general business sales were 13,948,000 MWh and in 2011 general business sales were 13,734,000 MWh, for a decline of 214,000 MWh or 1.5 percent. ICIP's numbers can only be reached by comparing the 2008 sales with the 2011 sales, which fails to account for the May 2009 load forecast that was used to reassess the need for Langley. Further, the arguments regarding reduced load forecast were brought before and evaluated by the Commission when it granted the CPCN. The Commission explicitly addressed this, "we find that it [the Company] has, in fact, recognized load diminishment and incorporated this into its adjustments to forecasts in December 2008 and May 2009." Order No. 30892 at 23. The Commission's decision recognizes that, in spite of relatively short-term declining loads, the projection of future need, and the long-lead time of the project justified moving forward with Langley. *Id.* at 10, 23. A review of

2012 loads through April shows loads approximately 93 percent of comparable 2008 loads (January through April) and over 97 percent of comparable 2009 loads (January through April).

Idaho Power's forecasts updated after September 2009 continued to demonstrate the necessity and usefulness of Langley. Company Witness Lisa Grow's testimony in this docket states that the 2011 IRP load and resource balance includes the latest load forecasts and takes into account load reductions due to Hoku Materials, Inc. and increased PURPA generation. Grow Direct Testimony at 16. Without Langley, the updated peak-hour load and resource balance shows July deficits of 28 MW in 2012, 169 MW in 2013, and 224 MW in 2014. When Langley is not necessary to meet load, funds generated from surplus sales will flow back to the customer through the annual Power Cost Adjustment filing.

In addition to serving load, management also evaluated Idaho Power's ability to serve load in an emergency without Langley. Idaho Power filed a Loss of Load Expectation ("LOLE") study with its 2011 IRP, which with the inclusion of Langley, shows that Idaho Power would stay within or below the target range for the industry. However, when Langley is removed, the LOLE increases rapidly. The following chart shows the 2011 IRP preferred alternative forecast, the preferred alternative revised forecast (which includes Langley and other planned future resources such as Boardman to Hemingway), and the preferred alternative revised forecast with Langley removed. The typical metric used in the utility industry to assess probability-based resource reliability is a LOLE of 1 day in 10 years. Idaho Power has instead calculated the LOLE on an hourly basis to evaluate the reliability at a more granular level. The 1-day-in-10-

years metric is roughly equivalent to 0.5-1.0 hours per year. The results of the sensitivity analysis are shown below.[3]



The sharp decline between 2015 and 2016 reflects the anticipated impact of the Boardman to Hemingway transmission line; yet the forecast again climbs out of the target range beginning in 2019. As described in the next section, Langley will and

[3] The LOLE analysis is performed on a monthly basis to permit capacity de-rates for maintenance or lack of fuel (water). The assessment assumes critical water conditions at the existing hydroelectric facilities. As mentioned in the 2011 IRP, Idaho Power uses a capacity benefit margin ("CBM") of 330 MW in transmission planning to provide the necessary reserves for unit contingencies. The CBM is reserved in the transmission system and is sold on a non-firm basis until forced unit outages require use of the transmission capacity. The 2011 IRP analysis assumes CBM transmission capacity is available to meet deficits due to forced outages. The model uses the IRP-forecasted hourly load profile, generator/purchase outage rates (EFORd), and generation and transmission capacities to compute a LOLE for each hour of the first 10 years of the IRP planning period. Demand response programs were modeled as a reduction in the hourly load during the mid-week peak hours rather than as a dispatchable resource due to the limited energy of the demand response programs.

already has operated to minimize or prevent losses of load when the system was under duress.

F. Langley Will Provide System Reliability Benefits.

Langley will assist in maintaining the balance of resources to load during periods when the transmission system is impaired. For example, in July 2010, a fire erupted in the hills north of Glenns Ferry, Idaho, burning nearly 4,000 acres. It damaged three transmission lines, dividing the Company's system in half. To stabilize the eastern system, Valmy was dispatched. It took crews almost a week to repair the lines and get them back in service. Langley will likewise provide stabilization during system emergencies and has already done so. When a strong storm with high winds rolled through southern Idaho on Monday, June 4, 2012, it knocked down hundreds of power poles and power lines, and heavily damaged electric facilities in the McCall to Garden Valley, Boise to Idaho City, and the Twin Falls areas. Valmy was dispatched as allowed under the emergency provisions of its Operation Agreement to supply energy to the eastern side of the system, limiting the flows on the impaired transmission facilities that split the system in two. Langley energy helped maintain load balances on the western side of the system, as the plant was running for testing purposes at the time the generation need arose. These resources are critical to Idaho Power's ability to maintain the system during periods when the system is constrained due to transmission facility outages and during peak loading periods. The reliability of Idaho Power's system depends on having a diverse portfolio of dispatchable resources with different fuel types and geographic areas to maintain load balance across our system; Valmy and Langley provide that diversity.

Langley will provide increased reliability benefits to Idaho Power's customers as a base load plant upon commercial operation. The generation output from the plant for load service will mitigate reliance upon non-firm transmission used to import energy purchased from the market into Idaho Power's service territory, particularly during summer months with high peak loads. For example, during system load peaks occurring in July and August 2011, Idaho Power was relying on imports of up to 132 MW over non-firm transmission from the Pacific Northwest. Langley's capacity is expected to alleviate reliance on non-firm transmission during peak demand periods like those experienced during the summer of 2011. Even greater benefits will exist during years having lower Snake River Basin streamflows as compared to 2011's extraordinarily high water year.

Additional reliability will be gained with increased regulating margin necessary for the challenges of integrating variable renewable generating resources. While precise operating parameters for Langley will be determined through actual commercial operation, it is anticipated that Langley within a one-hour time frame will be able to move its power output between the 60 percent and 100 percent loading level. This amount of flexibility will provide the power system with approximately 100 MW of much-needed intra-hour dynamic capacity critical to the successful integration of intermittent resources currently connecting to the Idaho Power system. When Langley is in operation, it will be able to assist by ramping down output when variable generation increases, and ramping up output when the variable generation falls off.

There are three additional areas of electrical power system performance where Langley provides measureable reliability benefits: post-disturbance loading and

voltage, reactive margin, and system stability. They all are measurements of the system performance following an electrical system disturbance, such as the outage of a transmission line. This entails the analysis of the power system reliability performance through power flow and stability simulation. When conducting the studies, system load and generation conditions are set to model an hour such as the peak summer load. Facility voltages and electric current flows are calculated following the simulation of facility outages (post-disturbance) and evaluated against specified performance criteria of the North American Electric Reliability Council and Western Electricity Coordinating Council. The studies determine the maximum reliable power transfer capability based on the post-disturbance substation voltages, facility overloads, reactive margin (the margin that exists from the point where voltage collapse may occur), and stability of the system.

The summer loading condition that stresses the reliability of Idaho Power's western transmission system occurs when power transfers from the Pacific Northwest add to the generation from the Hells Canyon Complex and cross the transmission lines to serve the Treasure Valley peak load hours. Idaho Power analyzed this system condition prior to the addition of Langley and again with Langley included to determine the reliability benefits gained. The study results demonstrate improved reliability as described below.

A 9 percent reduction in post-disturbance loading level is achieved with Langley included in the simulation. More specifically, the Oxbow-Lolo 230 kV line post-disturbance loading is reduced from 109 percent to 100 percent of the short-term emergency rating when an outage of the Brownlee-Hells Canyon 230 kV line occurs.

Additionally, following the Brownlee-Boise Bench #3 and the Brownlee-Horse Flat 230 kV double line outage, the Oxbow 230 kV to 138 kV transformer post-disturbance loading is reduced from 111 percent to 102 percent. Similarly, post-transient voltage deviations for the limiting outages are also improved when Langley is included.

Reactive margin was calculated at transmission substation locations for both the critical single facility and double facility outages described above. A significantly larger margin, increasing from 250 MVAR[4] to 650 MVAR, is demonstrated when Langley is included in the analysis. As a point of comparison, Idaho Power's reliability criteria require a minimum reactive margin of 250 MVARs for single element outage and 200 MVARs for double element outages. Additionally, when including Langley in the simulation, the system transient performance clearly improves following the double line outage of the Brownlee-Boise Bench #3 and the Brownlee-Horse Flat 230 kV lines. In short, Langley will make Idaho Power's system more reliable by improving system performance following electrical system disturbances.

G. <u>Ric Gale's Testimony Is Taken Out Of Context and Misapplied By ICIP</u>.

Page 6 of ICIP's Comments and page 4 of IIPA's Comments refer to a segment of Ric Gale's oral testimony from the technical hearing in Case No. IPC-E-09-03, Idaho Power's request for a CPCN for Langley, which was quoted on page 31 of Commission Order No. 30892. In the referenced segment of testimony, Ric Gale was responding to a question regarding the potential rate impact of Langley.

> [I]f you just simply lay that rate base and depreciation and such onto our current rates, you get a number close to . . . six or seven percent. If you play it forward into 2012 and escalate the revenue and evaluate it against other alternatives, its diminished, I think, close to three or four

[4] MVAR, an abbreviation of Mega Volt Amperes Reactive, is a measurement of reactive power.

> percent, and then in comparison to alternatives, maybe nothing at all, because you can't just view the rate impact in isolation. There's going to be a set of costs under which you're operating at that point in time.
>
> Case No. IPC-E-09-03, Tr. at 220.

ICIP and IIPA suggest that the Commission's decision to issue a CPCN for Langley was influenced by the hypothetical rate impact scenario described by Mr. Gale. The Company disagrees with ICIP's and IIPA's interpretation of Mr. Gale's response. Mr. Gale's response to this inquiry correctly pointed out that rate impact, measured in terms of the percentage change, is a fluid estimate that is dependent upon the Company's revenues and revenue requirements at a point in time. The percentage increase metric is the ratio of revenue deficiencies to total revenue. In the referenced testimony, Mr. Gale explained that under a scenario where the Company experiences revenue growth, the resulting percentage increase of adding Langley to rate base is naturally reduced. This is simply a function of the denominator in the percentage change calculation growing while the numerator remains the same. Mr. Gale goes on to point out that absent the generation from Langley, the Company would have to incur "alternative" costs to serve loads and the rate impact of Langley compared to the rate impact of the "alternative" may result in no difference at all. Mr. Gale's response covers a fundamental principle of utility revenue requirements and general ratemaking and the same response would be true of any future investments. While the percentage change metric is quite helpful in communicating the bill impact of a specific current rate action, it provides little to no value regarding the technical and economic viability of a resource.

ICIP and IIPA misapply Mr. Gale's response to the rate impact question to suggest that Commission was led to believe that the Company would not file a single-

issue rate request regarding Langley. Nothing in Mr. Gale's referenced testimony discussed the Company's plans with regard to the type of revenue requirement proceeding that it envisioned for Langley. Mr. Gale's response simply pointed out that there could be a range of possible rate impact scenarios that could exist under certain assumptions regarding the relationship between future revenues and revenue requirements.

H. <u>SRA's Mischaracterization of Construction Work in Progress ("CWIP")</u>.

Idaho Power does not fully understand the portion of SRA's comments entitled, "Customer Burden for an Unfinished Asset." However, the Company notes that it has not requested or received approval of Langley related CWIP in rate base. CWIP is the accumulation of costs associated with the construction of an asset, including the cost of financing the construction expenditures. The Company contends that including CWIP in rate base is a beneficial financing tool for constructing new generation, especially any multi-year large project, and is an accounting tool used for all investments, not just Langley. The Commission stated they were open to considering CWIP as construction progressed, but found the record in Case No. IPC-E-09-03 to be insufficient to award CWIP at that time. Order No. 30892 at 40. When CWIP is not included in rate base, as is the case with Langley related CWIP, *Idaho Code* § 61-502A states "the Commission is required to "allow a just, fair and reasonable allowance for funds used during construction [AFUDC] or similar account to be accumulated, computed in accordance with generally accepted accounting principles." Order No. 30892 at 33. Generally, AFUDC is recovered over the life of an asset when it is included in rate base. The Commission allowed the accrual of AFUDC "based on the actual amounts, timing and

borrowing rate for funds needed to construct the plant." Order No. 30892 at 40. Ratemaking assurances like those granted in Order No. 30892 pursuant to *Idaho Code* § 61-541 are not analogous to a "CWIP-like regulatory regime for new asset cost recovery." SRA Comments at 2.

The SRA continues with its mischaracterization of the Company's request in this proceeding, stating that "[w]hile this application is not a case of CWIP, it has some CWIP-like components, including the request for cost recovery before the asset is operating." SRA Comments at 2. However, Langley is currently operating in test mode and, although Idaho Power does not have a precise commercial operation date for Langley yet, it will be in commercial operation prior to rates becoming effective on July 1, 2012. Idaho Power will advise the Commission in writing as soon as commercial operation occurs.

III. CONCLUSION

The Langley Gulch power plant will provide low-cost energy to Idaho Power customers and capacity to integrate PURPA generation. Langley will increase system reliability and provide flexibility for integration of intermittent resources. After receiving Commission approval to move forward in September 2009, Idaho Power actively assessed the need for Langley, kept the Commission apprised of its progress, and continued to verify its importance through load forecasts.

The costs of the RFP Team are appropriately included in the Company's recovered investment. The Langley to Wagner Tap transmission line should also be included because future permitting, demolition, and reconstruction costs and risks were significant obstacles to building a 138 kV line and rebuilding a 230 kV line at a later date.

Valmy is not appropriately addressed in this proceeding and the AURORA runs put forth by IIPA are not valuable or useful considering the inputs. The Commission should use the method set forth in the Application for NPSE where the base-level inputs have already been examined and approved by the Commission.

Therefore, as set forward in its previously filed Application and testimony, Idaho Power respectfully requests the Commission issue its Order approving the Company's request to increase its annual revenue by $59,869,823 to recover its $390,942,172 of rate base investment in Langley, to be effective July 1, 2012.

DATED at Boise, Idaho, this 13th day of June 2012.

Lisa D. Nordstrom

LISA D. NORDSTROM
Attorney for Idaho Power Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 13th day of June 2012 I served a true and correct copy of IDAHO POWER COMPANY'S REPLY COMMENTS upon the following named parties by the method indicated below, and addressed to the following:

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