BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 53

In the Matter of IDAHO POWER COMPANY 2011 Integrated Resource Plan	STAFF'S FINAL COMMENTS AND RECOMMENDATIONS

Following are Staff's final comments and recommendations related to the Idaho Power 2011 Integrated Resource Plan (IRP). In these final comments, Staff discusses its analyses and conclusions regarding the IRP, and addresses concerns raised in initial comments by the Citizens Utility Board (CUB), and the Renewable Northwest Project (RNP). In addition, Staff addresses issues raised by Idaho Power in its reply comments. Staff recognizes these comments do not address all of the concerns raised in this docket. In its draft proposed order, Staff provides a comprehensive discussion of the concerns raised by parties.

Staff recommends that the Commission acknowledge Idaho Power's 2011 IRP with revised Action Items as reflected below. Staff explains in the discussion below the reasons underlying these recommended revisions.

Near-Term Action Plan (2011-2020)

Demand-Side Resource Action Items

Action Item 1 - Current Portfolio Energy Efficiency - In 2015, the forecast reduction for 2011–2015 programs will be 69 aMW; by the year 2020, the reduction across all customer classes increases to 133 aMW. By the end of the IRP planning horizon in 2030, 191 aMW of reduction is forecast to come from the current energy efficiency portfolio, with 80 percent of that reduction coming from programs serving commercial and industrial customers.

Action Item 2 - New Portfolio Energy Efficiency - In 2015, the new and expanded energy efficiency programs will reduce average loads by 13 aMW; in 2020, average loads will be reduced by 25 aMW. The full 20-year capacity of the program additions and changes is 42 aMW of average demand reduction.

Action Item 3 - Demand Response - The levels of demand response determined for the 2011 IRP analysis is 330 MW for summer 2011, 310 MW in 2012 when the Langley Gulch plant comes on line, and 315 MW in 2013 and 2014. In 2015, the demand response level used in the IRP analysis is 321 MW and then 351 MW from 2016 through the end of the planning period.

Action Item 4 – Conservation Voltage Reduction - The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The Company will propose an action plan in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's supply-demand balance forecasts.

Supply-Side Resource Action Items (Preferred Portfolio)

Action Item 5 - Solar - Issue a request for proposal (RFP) before the end of 2011 to design and construct a 500-kW–1-MW solar PV resource to be located in Idaho Power's service area. Evaluate proposals by mid-2012, and if a successful bidder is identified, file a request with the IPUC for a CPCN. If approved, have the facility on line as early as the end of 2012.

This solar resource will satisfy the State of Oregon's Solar PV Pilot Program requirement to build a 500-kilovolt (kV) solar PV project. Continue working with the OPUC to determine if this facility would have to be built in Oregon, which may impact the structure of the RFP.

Action Item 6 - Power Purchase Agreements - Complete 83 MW in market purchase from the east side of Idaho Power's system. The purchase is necessary to cover a summer peak-hour deficit in 2015 that exists before the Boardman to Hemingway line becomes available in 2016.

Action Item 7 - Transmission – ACKNOWLEDGED WITH REQUIREMENT FOR ANALYSIS UPDATES. Continue to make progress on the Boardman to Hemingway transmission project between now and the completion of the 2013 IRP, and plan to begin work on permitting and initial designs shortly after the completion of the 2013 IRP.

As the Company proceeds with the B2H project, its project assumptions (for example, construction cost estimates, equity partnership estimates, third-party subscription estimates, and wheeling revenues) will be updated and analyzed in the 2013 IRP.

Supply-Side Resource Action Items (Alternative Portfolio)

Action Item 8 - Solar – NOT ACKNOWLEDGED AS PART OF THIS IRP ~~as described for the preferred portfolio.~~

Action Item 9 - Simple Cycle Combustion Turbine – NOT ACKNOWLEDGED AS PART OF THIS IRP ~~170 MW in 2015, 170 MW in 2017, and 94 MW in 2019. If the Boardman to Hemingway transmission project is delayed, begin the acquisition process for the 2015 SCCT as early as 2012.~~

Other Action Items

Action Item 10 - Renewable Energy Certificate Management - As detailed in the REC Management Plan, continue selling RECs in the near term until they are needed to meet a federal RES.

Action Item 11 - Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants

In its next IRP Update, Idaho Power will include an Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants. The Evaluation will investigate whether there is flexibility in the emerging environmental regulations that would allow the Company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives. The Company will also conduct further plant specific analysis to determine whether this tradeoff would be in the ratepayers' interest.

Long-Term Action Plan (2021-2030)

Action Item 12 – Long-Term Action Items – NOT ACKNOWLEDGED AS PART OF THIS IRP ~~as outlined in IRP Table 10.2~~

Final Comments

Staff has organized its final comments by subject, cross referencing the related IRP Action Item. Staff assigned action item titles and numbers to facilitate presentation.

Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants (Action Item 11)

Recommended Requirement

Staff recommends addition of the following action item:

Action Item 11 - Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants

In its next IRP Update, Idaho Power will include an Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants. The Evaluation will investigate whether there is flexibility in the emerging environmental regulations that would allow the Company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives. The Company will also conduct further plant specific analysis to determine whether this tradeoff would be in the ratepayers' interest.

Discussion

CUB and RNP recommend that the Commission require Idaho Power to analyze, in this IRP, the costs and risks of maintaining its coal plants, and how carbon costs and environmental regulations could alter their cost-competitiveness in the future. They continue by commenting on the importance that the analysis be performed before the utility commits to significant investments, and before the utility loses the flexibility of the best available retrofit technology (BART) regime to exchange interim investments for early closure.

Idaho Power replies that in its September 20, 2011, IRP presentation to the Commission, it presented, at a very high level, a range of costs that could potentially result if certain environmental regulations were implemented. That high level analysis demonstrated that even if the Company were required to spend the estimated amount to comply with potential federal environmental regulations, those costs would still be less expensive than constructing replacement natural gas generation resources. Idaho Power then states that until the scope and substance of these potential regulations is more certain, the Company can only speculate as to the extent the rules will apply to its coal plants. Correspondingly, any cost estimate prepared by Idaho Power to conduct the unit-by-unit cost impact analysis as requested by CUB would be highly speculative as well. The Company notes that speculation does not make for prudent utility planning.

Staff agrees with CUB and RNP that it is important to analyze the costs and risks of continuing operation of the Company's coal plants, and how carbon costs and environmental regulations could alter their cost-competitiveness in the future. In considering the issue of further coal plant analysis, Staff notes its conclusion in initial comments that Idaho Power's 2011 IRP, by virtue of its September 20, 2011 presentation to the Commission, provides an evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations.

Following initial comments, Staff received and evaluated the Company's responses to data request 42. The data request responses included a confidential spreadsheet presenting a breakdown of environmental compliance costs, by coal fired generation unit. The responses also included a confidential spreadsheet calculating the revenue requirement and resulting cost per megawatt-hour (MWhr) used in the evaluation presentation to the Commission. This second spreadsheet aggregates the costs for all the Company's coal fired generation resources. In its review of the data request confidential spreadsheets, Staff found that Idaho Power considered and analyzed the suite of environmental compliance cost elements that are known and reasonable to consider at this time. Staff observes that the coal fired generation resource evaluation presentation and responses to data requests support continued use of the existing coal resources.

Staff concludes that, for the present time, there is sufficient evidence supporting continued use of the Company's existing coal fired resources as part of a resource strategy with the best combination of cost and risk for Idaho Power and its ratepayers. As a result, Staff does not agree with CUB and RNP to not acknowledge the 2011 IRP pending the completion of further coal plant analysis. This conclusion that the information provided to date supports continued use of the existing coal resources forms the basis for considering other action items in Idaho Power's 2011 IRP in more detail.

Staff recommends that Idaho Power be required to further investigate whether there is flexibility in the emerging environmental regulations that would allow the Company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives. In addition, Staff recommends that Idaho Power conduct further unit specific analysis to determine whether this tradeoff would be in the ratepayers' interest. Staff recommends that the Company be required to provide this additional analysis in its 2011 IRP Update.

Boardman to Hemingway Transmission (Action Item 7)

Recommended Requirement

Staff recommends acknowledging the B2H transmission project with the requirement for Company analysis updates, as follows:

> Action Item 7 - Transmission – ACKNOWLEDGED WITH REQUIREMENT FOR ANALYSIS UPDATES. Continue to make progress on the Boardman to Hemingway transmission project between now and the completion of the 2013 IRP, and plan to begin work on permitting and initial designs shortly after the completion of the 2013 IRP.
>
> As the Company proceeds with the B2H project, its project assumptions (for example, construction cost estimates, equity partnership estimates, third-party subscription estimates, and wheeling revenues) will be updated and analyzed in the 2013 IRP.

Discussion

CUB argues in its comments that coal plant closures would free up transmission capacity. In evaluating this comment, Staff notes that the only coal fired resource in the vicinity of the B2H transmission project is Portland General Electric's Boardman plant, and that plant is assumed in this IRP to be shut down in 2020. As a result, in relation to the B2H project, there is no additional transmission capacity to be freed-up by coal plant retirements. Staff, therefore, does not recommend directing Idaho Power to delay the B2H project while completing the requested coal plant evaluation. Staff does recommend Idaho Power evaluate the B2H project in light of the findings of the coal plant evaluation to ensure optimal benefits and timing before moving forward with permitting and construction.

Staff generally agrees with the comments offered by RNP and CUB regarding the benefits the B2H transmission project brings. Staff typically conducts its analysis of transmission projects on the basis of quantifying the costs and benefits of the project. The B2H project, however, is proposed and justified as the primary resource in a portfolio representing the best combination of cost and risk for Idaho Power and its ratepayers. On that basis Staff evaluated the B2H project, as described below.

Idaho Power included the B2H project in its 2011 IRP Preferred Resource Portfolio.[1] The proposed B2H project involves constructing, operating, and maintaining a new single-circuit 500-kV transmission line of approximately 300 miles in length. The proposed route is between northeast Oregon and southwest Idaho.[2] The project's capital cost is estimated by the Company to be approximately $820 million.[3,4]

Double Counting of Allowance for Funds Used During Construction (AFUDC)

In Idaho Power's response to Staff data request 27,[5] the Company provided an estimated capital cost of approximately $820 million, inclusive of approximately $93 million in AFUDC. Assuming a 28 percent share, the Company estimated its portion of the project's capital costs at $229 million (28 percent of $820 million). However, in addition to the AFUDC included in the Company's estimated portion of $229 million, the Company also included $31 million of AFUDC to arrive at $260 million as calculated in Idaho Power's Attachment 1 to the Company's response to Staff data request 28.[6] Therefore, $31 million in AFUDC was double counted.

Staff addressed this double counting in Staff data request 48.[7] In Idaho Power's response, the Company represented that "[t]he Public Utility Commission of Oregon Staff is correct in that AFUDC was mistakenly included twice in the capital cost estimate for B2H in the IRP." In the same response to Staff data request 48, the Company updated the present value of revenue requirement (PVRR) of the B2H project to address the double counting, reducing it by $38 million from $316 million to $278 million.[8]

Commission Order No. 10-392, related to the Company's 2009 IRP, noted the small number of recent transmission projects and the case specific nature of any transmission project, make it difficult to vet key assumptions that will determine the cost to Idaho Power's retail customers of the B2H project. The Commission also noted its concern about this uncertainty was tempered by risk analyses showing that the "B2H portfolio" is the best portfolio for customers over a range of capital costs and third-party subscription levels. Accordingly, the Commission considered it reasonable to proceed with the B2H

[1] See Idaho Power's 2011 IRP, Chapter 1, "Summary," "Table 1.1," page 7.
[2] See Idaho Power's 2011 IRP, Chapter 5, "Supply-Side Resources," page 51.
[3] See Idaho Power's 2011 IRP, Chapter 5, "Supply-Side Resources," "Updated Cost Estimate," page 53.
[4] See Idaho Power's response to Staff Data Request 27.
[5] See Idaho Power's response to Staff Data Request 27.
[6] See Idaho Power's response to Staff Data Request 28.
[7] See Idaho Power's response to Staff Data Request 48.
[8] The reduction of approximately $38 million in PVRR is the equivalent of reducing $31 million of the project capital costs.

project based on the information available at that time. In that Order, the Commission also adopted Staff's recommendation that Idaho Power be required to update its B2H project assumptions (for example, construction cost estimates, equity partnership estimates, third-party subscription estimates, and wheeling revenues) in its 2011 IRP. At the Commission public meeting on September 7, 2010, the Company committed to continue to analyze and assess the B2H project as an uncommitted resource.

Staff has the same concerns with regard to the B2H transmission project in this 2011 IRP as it did in the 2009 IRP. As done by the Commission for the 2009 IRP, Staff tempers its concern with recognizing the project continues to be identified, through the 2011 IRP analysis, as the primary resource in the best portfolio for customers over a range of capital costs and third-party subscription levels. On this basis, Staff recommends the B2H project be acknowledged, but that as the Company proceeds with the B2H project, its project assumptions (for example, construction cost estimates, equity partnership estimates, third-party subscription estimates, and wheeling revenues) should be updated.

Conservation Voltage Reduction (Action Item 4)

Recommended Requirement

Staff recommends an additional action item to address acquisition of cost effective conservation voltage reduction (CVR) resources, as follows:

> Action Item 4 – Conservation Voltage Reduction - The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The Company will propose an action plan in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's supply-demand balance forecasts.

Discussion

The Company reply comments state that most of the savings realized by Idaho Power from CVR occurred in the years prior to the 2011 IRP planning horizon, and CVR impacts are indirectly integrated into the load forecast. Staff respectfully disagrees with the Company's statement that:

> CVR impacts are indirectly integrated into the load forecast by virtue of being embedded in the historical data that is used as part of preparing the load forecast. Mathematically, the impact is effectively being attributed to other variables such as codes, manufacturing standards, weather, economy, and trend or error.[9]

[9] Company Reply Comments of Nov. 8, 2011 at 11.

Staff sees this statement is logically incorrect. The Company agrees that there is an untapped CVR and that this resource is "very cost effective."[10] The Company indicates it is pursuing further reductions in load from continued implementation of CVR.[11] Mathematically, these future reductions in the need will affect the need for resource additions and are not included in the IRP.

Staff re-affirms its initial comments and proposes that the addition of a CVR action item be part of the Commission acknowledgement of the IRP in this docket.

Demand Response (Action Item 3)

Recommended Requirement

Staff recommends acknowledgement of Action Item 3, as the Company proposed.

> Action Item 3 - Demand Response - The levels of demand response determined for the 2011 IRP analysis is 330 MW for summer 2011, 310 MW in 2012 when the Langley Gulch plant comes on line, and 315 MW in 2013 and 2014. In 2015, the demand response level used in the IRP analysis is 321 MW and then 351 MW from 2016 through the end of the planning period.

Discussion

Based on Page 41 of the 2011 IRP, the goal of demand response programs at Idaho Power are to reduce summer peak load during periods of extremely high demand, and minimize or delay the need to build new supply-side resources. The Company indicates that in this IRP cycle the evaluation of demand response programs was switched from an "all cost-effective [demand side management] DSM" approach to a "need-based" approach. An analysis conducted as part of Idaho Power's 2011 IRP concluded that, for Idaho Power, there is a defined optimal amount of demand response for Idaho Power's system. In its analysis, the costs from an energy perspective for demand response were compared to the energy costs of owning and operating a simple cycle combustion turbine (SCCT). From Staff's perspective, the appropriate level of demand response should not be determined based on a comparison of the cost per hour of demand response to the hourly cost of energy produced by an SCCT. Staff contends that this type of analysis contradicts the Company's own statement regarding why demand response is needed, to offset the need for new capacity resources, and therefore such a comparison is inappropriate and potentially misleading. In its filing, the Company confirms that demand response is less expensive than an SCCT, from a capacity perspective, which is how Staff contends program cost-effectiveness is determined.

The Company reports the following historical and projected levels of peak hour load reduction due to demand response:

[10] Ibid at 12.
[11] Ibid.

Year	Megawatt of Demand Response peak hour load reduction (MW)[12]
2008	61
2009	218
2010	336
2011	330
2012	310
2013 and 2014	315
2015	321
2016 and beyond	351

Between 2008 and 2010 the Company increased the amount of demand response by more than a factor of five.

Growth in summertime peak-hour demand continues to drive the Company's need for additional resources. The avoided capacity resource for peak summer hours and for demand response programs is based on a 170 MW natural gas fired SCCT. The marginal resource the Company is trying to avoid with DSM efforts for summer on peak is an SCCT. The estimated levelized capacity cost of building a new SCCT is $94/kW over a 30-year expected life. For demand response, or direct load control, DSM programs operating during summer peak, the $94/kW becomes the cost threshold for program cost effectiveness. The Company indicates that in 2030, the projected 351 MW of demand response has a levelized cost of $48/kW.

Staff recommends that the Company pursue all cost effective demand response through existing programs (Irrigation Peak Rewards, A/C Cool Credit and FlexPeak Management) and consider new programs as applicable, including those using third-party program administrators and those that would extend into September when peak management is also an issue. In the long term planning horizon, the Company should continue to consider how demand response could offset need for new resources and how current seasonal limitations could be overcome through modified program design. The Company should pursue all the demand response it can in order to both offset need for supply side resources, and if properly designed, to offset the need for market purchases in peak periods.

In summary, Staff questions whether the Company needs to identify an optimum level of demand response, as it indicates the Company is now doing. The Company's first attempt to demonstrate this optimum level by comparing hourly energy costs of demand response to hourly energy costs of an SCCT is not convincing, and simply does not make sense. If there is an optimum, the Company has failed to convince Staff. Staff

[12] Based on Page 42 of Idaho Power 2011 Integrated Resource Plan

continues to believe demand response is the least cost, least risk resource, so it should be maximized.

Energy Efficiency (Action Items 1 and 2)

Recommended Requirement

Staff recommends acknowledgement of Action Items 1 and 2, as proposed.

Action Item 1 - Current Portfolio Energy Efficiency - In 2015, the forecast reduction for 2011–2015 programs will be 69 aMW; by the year 2020, the reduction across all customer classes increases to 133 aMW. By the end of the IRP planning horizon in 2030, 191 aMW of reduction is forecast to come from the current energy efficiency portfolio, with 80 percent of that reduction coming from programs serving commercial and industrial customers.

Action Item 2 - New Portfolio Energy Efficiency - In 2015, the new and expanded energy efficiency programs will reduce average loads by 13 aMW; in 2020, average loads will be reduced by 25 aMW. The full 20-year capacity of the program additions and changes is 42 aMW of average demand reduction.

Discussion

The Company's IRP pointed out that energy efficiency also results in peak load reduction. Currently, cost effectiveness of existing and new energy efficiency programs is high. Idaho Power is pursuing 42 average megawatts (aMW) of new energy efficiency load impact by 2030, at a total resource cost benefit cost ratio of 3.2, a total resource levelized cost of $0.051/kWh and utility levelized cost of $0.026/kWh.

Staff recommends the Company continue to pursue all cost effective energy efficiency as the lowest cost resource for customers.

Alternative Portfolio (Action Items 8 and 9)

Recommended Requirement

Staff recommends the alternative resource portfolio not be acknowledged as part of this IRP.

Action Item 8 - Solar – NOT ACKNOWLEDGED AS PART OF THIS IRP ~~as described for the preferred portfolio.~~

Action Item 9 - Simple Cycle Combustion Turbine – NOT ACKNOWLEDGED AS PART OF THIS IRP ~~170 MW in 2015, 170 MW in 2017, and 94 MW in 2019. If the Boardman to Hemingway transmission project is delayed, begin the acquisition process for the 2015 SCCT as early as 2012.~~

Discussion

Staff agrees with RNP, but for different reasons, that the alternative resource portfolio should not be acknowledged. Idaho Power proposes the alternative portfolio as its plan should the B2H transmission project be delayed. Staff finds there are mechanisms available within the existing IRP process to deal with unforeseen circumstances, such as a delay in acquisition of a major resource. The primary mechanisms are the IRP Updates and new IRPs on a two year cycle. Given existing mechanisms to deal with a delay in the B2H project, Staff does not recommend acknowledging the alternate resource portfolio.

Long-Term Action Items (Action Item 12)

Recommended Requirement

Staff recommends the long-term action items not be acknowledged as part of this IRP.

Action Item 12 – Long-Term Action Items – NOT ACKNOWLEDGED AS PART OF THIS IRP ~~as outlined in IRP Table 10.2~~

Discussion

Idaho Power's long-term action items occur in the 2021 through 2030 time period. Staff takes no issue, at this time, with the content of the long-term action items. Staff does find that IRP Guideline 4(n) calls for an action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources. Because of the desired focus in IRP Guideline 4(n) on actions over the next two to four years, Staff does not recommend acknowledging the long-term action items.

Load Forecast

Recommended Requirement

None

Discussion

Idaho Power admits in reply comments that the current national economic slowdown has an impact on its load forecasts. Notwithstanding, the Company seeks acknowledgement of its 2011 IRP based upon the best information available at the time the IRP was developed. Staff agrees with Idaho Power that, for IRP acknowledgement purposes, it is not appropriate to pick-and-choose selected items, such as load forecasts, and update only some items without updating all other aspects of the IRP. Staff also desires to evaluate the complete forecast process. Staff is concerned about basing its recommendations on a July 2010 forecast that has proven to be inaccurate.

The table below presents historical data of Idaho Power's performance in the state of Oregon (from 2010 Oregon Utility Statistics book):

	Energy Sold to Retail Customers	Average Number of Customers	Residential Average Number of Customers	Residential Average kWh per Customer
2001	626,014	17,379	12,933	14,331
2002	628,718	17,461	12,976	14,565
2003	628,952	17,689	13,015	14,468
2004	665,045	17,851	13,078	14,554
2005	676,230	17,953	13,119	14,578
2006	703,349	17,912	13,180	15,128
2007	693,458	18,265	13,292	15,044
2008	670,066	18,402	13,343	15,273
2009	673,062	18,450	13,385	15,380
2010	628,941	18,455	13,419	14,126
Compound Growth/Yr	0.05%	0.62%	0.38%	-0.14%

The table shows an actual annual load growth of 0.05 percent over the 2001 to 2010 time period. This is substantially less than the 1.4 percent average-energy growth forecast by Idaho Power for this IRP. Although the IRP analysis considers a range of load growth forecasts from 1 to 1.8 percent, the 0.05 percent actual annual load growth since 2001 is outside the range considered. However, the one percent load growth suggested by Staff is within range considered in the IRP.

Recognizing the Company near-term action plan does not request acknowledgement of new supply side resource acquisition, but rather acknowledgement to continue to make progress on the B2H project, Staff does not recommend a change to the 2011 IRP based on an updated load forecast. Instead, Staff highlights the need for the 2011 IRP Update and the 2013 IRP to be based on an updated load forecast that, as accurately as possible, reflects current conditions.

As noted in Staff's initial comments, IRP page 8 discusses what Idaho Power calls "New Large Loads." The Company proposes adding 80 MW of peak hour load to its 2013 IRP load and resource balance to provide the ability to serve new loads. The Company states in the IRP that the inability to serve new large loads impacts Idaho's economy.

Related to the new large load issue introduced in its initial comments, Staff concludes, barring evidence to the contrary, it is appropriate to include an allowance for new large loads in the load forecast as an additional firm load category, but the new large load must be based on specific supporting documentation.

Risk Analysis

Recommended Requirement

None

Discussion

Staff finds two troubling aspects to Idaho Power's stochastic risk analyses – particularly as the Company's analyses are contrasted with the more conventional approaches used by other Oregon utilities:

1. Rather than ascribing standard normal or lognormal statistical distributions to the risk factors, the Company sets a year-by-year upper and lower limit to each of the factors.

2. The purpose of stochastic risk analysis is, in particular, to obtain estimates of upper limits (e.g., 90th percentile) to the multi-year revenue requirements associated with the various portfolios. Generally, this task is accomplished by randomly varying the risk factors on a year-by-year basis and calculating what the revenue requirement (or "sample value") would be each year given the values of those risk factors.

Idaho Power's approach is "totally" different. How a single revenue requirement "sample value" for a given year is obtained is described as follows:

a. While holding all other risk factors at their base values, the Company calculates the highest and lowest revenue requirement that would come forth after taking a particular risk factor's extreme upper and lower limits as described in 1., above.

b. The revenue requirement range just developed is divided into five equal-sized parts, with five "values" comprising the mid-points of those parts.

c. One "value" for the revenue requirement is chosen, with each of the five values from b. being given an equal chance of being chosen.

d. a. b. and c. are repeated for all the other risk factors, yielding a total of six "values" (where six is the number of different risk factors considered).

e. The "sample value" for the year is the average of those six individual "values."

The following is a simplified example contrasting the PacifiCorp and Idaho Power approaches to calculating a particular year's revenue requirement for a given portfolio:

1. Assume just two risk factors, gas prices and load growth.

2. A single “sample value” under the more standard approach described above might, for example, be what the revenue requirement would be if the gas price was “drawn” as a particular low value from a lognormal distribution, and the load was “drawn” as something above average from a normal distribution.

3. By contrast, Idaho Power’s comparable “sample value” would be the average of two revenue requirements, where one was “drawn” from the five equal-sized array of revenue requirements where only gas prices varied and the other was “drawn” from the similar array where only the load varied. So, what you will end up with is a revenue requirement that represents at once a likely deviant and the nominal value for each of the risk factors. A revenue requirement distribution thus derived is difficult to interpret compared to conventional revenue requirement distributions that are based on coherent combinations of risk factors.

Staff sees the basic problem with the approach used by Idaho Power (besides the uniform distribution assumptions) being that an adverse combination of two or more unfavorable risk factors will never be “sampled” because only one risk factor is allowed to depart from its base value for any one “draw.” Staff concludes that the stochastic risk analyses by Idaho Power likely do not provide reliable information in evaluating the risk dimension of the cost-risk analysis.

Staff recommends the next Idaho Power IRP should present risk analysis results based upon the more conventional approach described above. This recommendation does not preclude the Company from simultaneously presenting results based upon the methodology used in the current IRP. Specifically:

1. Rather than simply estimating upper and lower extreme values for the various risk factors, statistical distribution functions should be estimated. Also, when risk factor values are randomly drawn from those distributions, how the risk factors correlate with themselves on a year-by-year basis and, in a given year, with each other (if at all) should be taken into consideration – i.e., conditional distribution functions should be employed.

2. Calculate a sample year’s single revenue requirement for a particular portfolio by simultaneously employing all of the risk factor values that were randomly drawn for that year. That year’s value will combine with the single revenue requirement values for all the other subject years to yield a single net-present-value revenue requirement (NPVRR) for the subject (ten- or twenty-year) period. Repeating that process one hundred times will establish the distribution of NPVRRs for the given portfolio, and from that distribution can be obtained the median NPVRR and the upper-tail values.

In addition, Staff confirms its initial recommendation to include hydro generation variability as a risk variable/factor for the next IRP cycle. As stated in initial comments, Staff bases this recommendation on recognizing Idaho Power’s significant reliance on hydroelectric generation, and the IRP Guideline 1(b)1 listing hydroelectric generation as a source of risk and uncertainty that should be addressed.

Wind Integration Study

Recommended Requirement

None

Discussion

Staff agrees with RNP that Idaho Power should seek independent technical review of its wind integration study and meaningful opportunity for stakeholders to give feedback, before incorporating the study results into the next IRP.

Given that Idaho Power is in the process of preparing its wind integration study, Staff does not recommend, as suggested by RNP, redirecting that study to consider ways in which diversity and flexible balancing resources could lower its cost of integrating intermittent resources. Staff notes that wind integration studies to date have been designed to identify the cost of using existing resources to integrate intermittent resources. Staff sees the next generation of wind integration studies as the appropriate venue to explore and develop analytical techniques for identifying and evaluating methods for reducing the cost of integrating intermittent resources.

Staff recommends Idaho Power seek independent technical review of its wind integration study and meaningful opportunity for stakeholders to give feedback, before incorporating the study results into the next IRP. In addition, Staff recommends the Company's next wind integration study look for ways in which diversity and flexible balancing resources could lower its cost of integrating intermittent resources.

Other

Recommended Requirement

None

Discussion

Solar PV Resource

RNP encouraged Idaho Power, as it gains experience with solar PV through its demonstration project and Oregon solar capacity standard project, not to limit its evaluation only to the performance of single projects. RNP stated its belief that geographic dispersion of several solar projects could have a significant effect on smoothing the short-term variability of single projects. Staff notes and agrees with RNP's observations.

Capacity Planning Margin

Staff noted the process described on IRP pages 115 and 116 for back-calculation of a capacity planning reserve margin, effectively comparing the difference between the 50th and 70th percentile hydroelectric water conditions. Staff intended to explore whether this approach was still appropriate given the water issues described on IRP pages 15 and 16. Staff also noted the overlap between the capacity planning reserve margin and the capacity benefit margin used in the loss of load expectation analysis. Staff has no further comments or concerns related to this issue.

Firm Market Purchases

Staff noted IRP page 68 discusses transmission capacity limitations. In that discussion, Idaho Power stated that it does not typically rely on imports from the Intermountain Region for planning purposes. Staff stated its intent to investigate these limitations to consider whether Idaho Power's practice of not relying on these imports was still valid.

Idaho Power's response to Staff data request 52 presented a description of the limitations to relying on imports from the Intermountain Region, as discussed on IRP page 68. The Company stated:

> Idaho Power Company's transmission import capability from northern Nevada (262 megawatts ("MW")) only permits the import of Idaho Power's share of the Valmy Plant (262 MW). Therefore, additional power purchases on this path are substantially limited. Similarly, Idaho Power's share of the Bridger transmission system (711 MW) is full with the Company's share of the Jim Bridger Plant (711 MW). Idaho Power's market access from Montana is also limited (167 MW) and already fully subscribed with transmission service for network load customers and power purchases for native load service (167 MW).
>
> Transmission access from the Salt Lake City area has recently been upgraded with the addition of the Populus Substation and the two Populus-Terminal 345 kilovolt lines. However, the limiting factor as described in the 2011 IRP is the size of the summer peak load in the Salt Lake City area and the resources available to serve that load. The Utah area's summer peak load typically coincides with Idaho Power's summer peak. Compared to the summer peak generation capacity that is available in the Pacific Northwest, there is little surplus capacity in the Utah area for Idaho Power to reliably rely on to serve its summer peak loads.

Staff is satisfied the Company's response confirms the continuing applicability of its historical import limitation assumption.

Adherence of the Plan to Integrated Resource Planning Guidelines

Recommended Requirement

None

Discussion

Among parties to this docket there was unanimous agreement that Idaho Power's 2011 IRP, as filed on June 30, 2011, did not comply with Guidelines 4(g) and 1(c) because it failed to provide a comprehensive evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations. In response to this deficiency, Idaho Power, in its September 20, 2011 IRP presentation to the Commission, presented, at a very high-level, an evaluation of a range of costs that could potentially result if certain environmental regulations were implemented. That high level analysis demonstrated that, even if the Company were required to spend the estimated amount to comply with potential federal environmental regulations, the existing coal fired resources would still be less expensive than constructing replacement natural gas generation resources. By providing the information presented to the Commission on September 20, 2011, Staff believes the Idaho Power 2011 IRP reasonably complies with the IRP Guidelines.

Staff notes that Guideline 4(a), which requires an explanation of how the utility met each substantive and procedural requirement, was not provided. Attachment 1, prepared by Staff, is a table presentation of compliance by Guideline.

Staff notes that IRP Guideline 4(n) asks for an action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources. Idaho Power's 2011 IRP includes a chapter presenting its action plan, but that action plan presentation does not include demand side resource action items, and it does not include a concise presentation of the action items. As a result, Staff had to extract action items from the Demand-Side Resources chapter and the Action Plan chapter text, and assign a number to each for ease of reference. Staff recommends future IRPs include a concise listing of action items for all resources and resource related activities, with each action item numbered.

Dated at Salem, Oregon, this 6th day of December, 2011.

Erik Colville

Erik Colville
Senior Utility Analyst
Electric Rates & Planning

Attachment 1
Guideline Compliance Table

Idaho Power 2011 Integrated Resource Plan (IRP)

In considering whether to acknowledge an Integrated Resource Plan, the Public Utility Commission of Oregon reviews the Plan for adherence with its Guidelines for resource planning. The following table presents Staff's review of the IRP for adherence with Commission Guidelines, with each Guideline addressed separately. A complete copy of the Guidelines can be found in Commission Order No. 07-002 and Order No. 08-339.

Guideline		**Description**	**Location Where Addressed in IRP**
1	Substantive Requirements	Under Guideline 1, an electric utility should: a. Evaluate all resources on a consistent and comparable basis; b. Consider risk and uncertainty; c. Select a portfolio with the best combination of expected costs and associated risks and uncertainty for the utility and its customers; and, d. Be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	Chapters 1 and 9 present the method, modeling analysis, and results.
2	Procedural Requirements	Guideline 2 is a description of procedural requirements that require a utility to include the public as well as other utilities in the IRP planning process.	Chapter 1 discusses the IRP process, and specifies public involvement.
3	Plan Filing, Review, and Updates	Guideline 3 states that a utility must file its IRP two years from the date of acknowledgement of the previous plan.	Chapter 1 discusses the filing requirement. The 2009 IRP was acknowledged October 11, 2010 while the 2011 IRP was filed June 30, 2011.
4	Plan Components	Guideline 4 requires a utility to include 14 components in its IRP evaluation.	The 2011 IRP substantially included each guideline component. Inclusion of components (a) and (n) was inadequate and in need of improvement.
5	Transmission	Guideline 5 requires the Company to consider transmission as a resource option, taking into	Chapter 5 discusses transmission as a resource, and Chapter 7 discusses transmission

Guideline		Description	Location Where Addressed in IRP
		consideration its value for making additional purchases and sales, accessing less costly resources in remote locations, and improving reliability.	planning.
6	Conservation	Guideline 6 requires a utility to perform a conservation potential study periodically for its entire service territory. In addition, the Company should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	Chapter 4 and Appendix B discuss and present demand side, including conservation. Demand side resource actions were missing from the Chapter 10 Action Plan.
7	Demand Response	Guideline 7 states that a utility should evaluate demand response resources; including voluntary rate programs on par with other options for meeting energy, capacity, and transmission needs.	Chapter 4 and Appendix B discuss and present demand side, including conservation. Demand side resource actions were missing from the Chapter 10 Action Plan.
8	Environmental Costs	Guideline 8, as modified by Order No. 08-339, contains four requirements: a base case scenario, alternative portfolios against the base case scenarios, a trigger point analysis, and an Oregon compliance portfolio. The first requirement directs the Company to model what it considers to be the most likely regulatory compliance future for greenhouse gas emissions, as well as other possible credible scenarios. The second requirement discusses the treatment of these scenarios in its risk-analysis, PVRR cost and risk measures, and end-effect considerations. The third requirement directs the utility to identify a carbon dioxide compliance scenario that would lead to the selection of a portfolio that is substantially different from the preferred portfolio. The final requirement discusses the need for a separate portfolio, consistent with Oregon energy policies, if none of the previous portfolios achieves that consistency.	Chapter 6 discusses the range of carbon dioxide costs analyzed, the emission cost adders included in the analysis, and portfolios with zero emissions for analysis, and all analyzed portfolios were designed to comply with an assumed federal renewable energy standard. Chapter 9 presents modeling and results for carbon dioxide risk and renewable energy credit cost risk.

Guideline		Description	Location Where Addressed in IRP
9	Direct Access Load	Under Guideline 9 an electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	Chapter discusses and presents the load forecast, and Chapter 8 discusses and presents the load and resource balance.
10	Multi-state Utilities	Guideline 10 requires multi-state utilities to plan its generation and transmission systems on an integrated system basis that achieves a best cost/risk portfolio for its retail customers.	Chapter 1 discusses the multi-state status of Idaho Power.
11	Reliability	Under Guideline 11, an electric utility should: a. Analyze reliability within the risk modeling of the actual portfolios being considered b. Determine loss of load probability (LOLP), expected planning reserve margin, and expected and worst-case unserved energy by year, and c. Demonstrate that the selected portfolio achieves the utility's stated reliability, risk and cost objectives	Chapter 9 discusses the capacity planning reserve margin and the loss of load expectation (potential).
12	Distributed Generation	Guideline 12 recommends that utilities should evaluate distributed generation technologies on par with other supply-side resources.	Chapter 5 discusses distributed generation as a resource. Chapter 8 presents and analyzes a distributed generation portfolio.
13	Resource Acquisition	Guideline 13 establishes requirements for acquiring resources in the utility's action plan.	Chapter 10 presents the resource acquisition plan. As noted above in the descriptions for Guidelines 4, 6 and 7, the action plan was incomplete and could be improved.

ORDER NO.

ENTERED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 53

In the Matter of	)	
	)	PROPOSED ORDER
IDAHO POWER COMPANY	)	
	)	
2011 Integrated Resource Plan.		

DISPOSITION: PLAN ACKNOWLEDGED WITH EXCEPTIONS AND REQUIREMENTS FOR NEXT IRP UPDATE.

I. INTRODUCTION

Idaho Power Company (Idaho Power or the Company) seeks acknowledgement of its 2011 Integrated Resource Plan (IRP). This filing is in accordance with Public Utility Commission of Oregon (Commission) Order No. 07-002, as corrected by Order No. 07-047[1], which requires all regulated energy utilities operating in Oregon to engage in integrated resource planning. We acknowledge the plan with certain exceptions and requirements for the next IRP update that are discussed below.

The Commission requires regulated energy utilities to prepare integrated resource plans within two years of acknowledgment of the last plan. Prior to resource decision-making, utilities must involve the Commission and the public in their planning process. Substantively, the Commission requires that energy utilities: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) make the primary goal of the process selecting a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create a plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies. See Order No. 07-002.

The Commission "acknowledges" resource plans that satisfy the procedural and substantive requirements, and that seem reasonable at the time acknowledgment is given.

[1] The Commission originally adopted least-cost planning in Order No. 89-507 (Docket UM 180). The Commission updated the utility planning process in Docket UM 1056.

II. PROCEDURAL HISTORY

Idaho Power filed its 2011 IRP on June 30, 2011. A prehearing conference was held July 29, 2011, and a schedule adopted. Petitions to intervene were granted on behalf of Renewable Northwest Project (RNP), Portland General Electric Company, Oregon Department of Energy (ODOE), Move Idaho Power, and Stop Idaho Power. The Citizens' Utility Board (CUB) intervened by right.

On September 20, 2011, Idaho Power presented its IRP to the Commission at a Public Meeting. A technical workshop was held for parties in the docket on September 20, 2011. Staff and intervener initial comments were filed October 18, 2011. Company reply comments were filed November 8, 2011. Staff final comments and this draft order were filed December 6, 2011.

III. DISCUSSION

The primary issues in this IRP are discussed below, with the most significant discussed first. Each issue is also correlated with its corresponding Action Item in Idaho Power's IRP.

A. Issues

1. Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants (Action Item 11)

a. Parties' Positions

Initial Comments:

In CUB's initial comments it recognized Idaho Power does not wholly own or operate any coal plants, but that the Company does have a significant ownership interest in three large plants (Boardman, North Valmy, and Jim Bridger). These plants, CUB stated, provided 41 percent of its total 2010 generation. CUB pointed out these three plants will face increasing costs to comply with clean air regulations in the coming years. CUB stated that without an analysis of the investment in clean air retrofits to the coal plants that provide energy to Idaho Power, its position is that the Commission does not have adequate information to acknowledge any part of the clean air investment either explicitly or implicitly. CUB also concluded that it is difficult to identify items in the proposed Action Plan that would not be affected by a change in the fleet of coal units that provide energy for the Company.

CUB suggested that Idaho Power be required to conduct a unit-by-unit evaluation of its clean air investment costs, similar to that conducted by PGE for its Boardman plant, before the provisions relating to coal plant investment contained in its IRP are considered for acknowledgment. CUB also noted that Idaho Power has conducted a number of tipping point analyses in this IRP process. CUB respectfully requested that the Commission require the Company to conduct an additional tipping point analysis on the price of continuing to purchase energy from existing coal resources versus a number of replacement base load resources, such as combined cycle combustion turbines (CCCT) and renewables. CUB stated that, while such a study would not be as revelatory as a full AURORA model run, it could be compared to various estimates of potential clean air compliance costs to assess Idaho Power's level of compliance risk.

In conclusion, CUB recommended that the Commission not acknowledge any elements of the 2011 IRP until the Company submits its underlying analysis of the coal investment, and Staff and other parties have a chance to review and comment on that analysis. CUB eagerly awaits Idaho Power's additional unit-by-unit analysis and encourages the Commission to provide ample scheduling accommodation to the Company to ensure that its analysis is done properly and is not rushed, and to ensure that interveners have adequate time to review and comment upon that analysis.

RNP recommended that the Commission require Idaho Power to analyze, in this IRP, the costs and risks of maintaining its coal plants and how carbon costs and environmental regulations could alter their cost-competitiveness in the future. It stated the importance of an analyses of the type described in the comments of the Citizens' Utility Board be performed before the utility commits to significant investments, and before the utility loses the flexibility of the best available retrofit technology (BART) regime to exchange interim investments for early closure.

Staff's initial comments noted that IRP Guideline 4(g) requires the utility to identify key assumptions about the future, including assumptions about future environmental compliance costs. Idaho Power's 2011 IRP, by virtue of its September 20, 2011 presentation to the Commission, provides an evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations. Staff commented it requested and will evaluate a breakdown of the environmental compliance costs, by coal fired generation unit, used in its evaluation.

In its reply comments, Idaho Power noted that in its September 20, 2011, IRP presentation to the Commission, the Company presented at a very high level a range of costs that could potentially result if certain environmental regulations were implemented. Importantly, and as indicated in the slide presentation on September 20, the high-level estimates of forecast environmental costs were derived solely for purposes of providing a resource "tipping point" analysis to the Commission and interested parties; those forecast costs were not intended to serve as estimates of potential environmental compliance costs. That high level analysis demonstrated that even if the Company were required to spend the estimated amount to comply with potential federal environmental regulations, those costs would still be less expensive than constructing replacement natural gas generation resources. As indicated above, the forecast costs contained in the tipping point analysis were not included as part of the Company's 2011 IRP process because the costs are too speculative at this time.

Idaho Power stated that until the scope and substance of these potential regulations is more certain, the Company can only speculate as to the extent the rules will apply to its coal plants. Correspondingly, any cost estimate prepared by Idaho Power to conduct the unit-by-unit cost impact analysis as requested by CUB would be highly speculative as well. Speculation does not make for prudent utility planning.

The Company concluded by stating, it would not be appropriate for the Commission to refuse to "acknowledge any IRP that includes plans for future coal plant investments." Instead, the Commission should acknowledge the Company's 2011 IRP including the Company's preferred portfolio and, as part of that acknowledgement, require the Company to conduct the environmental compliance costs analysis requested by CUB as part of its 2013 IRP. This approach allows time for the proposed environmental regulations to become finalized so the Company can conduct more accurate environmental compliance cost analyses as well as afford CUB the opportunity to participate in the public process of preparing the Company's 2013 IRP during meetings with the IRP Advisory Council.

Staff Final Comments:

Revised Action Item

Staff recommends addition of the following action item:

Action Item 11 - Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants

In its next IRP Update, Idaho Power will include an Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants. The Evaluation will investigate whether there is flexibility in the emerging environmental regulations that would allow the Company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives. The Company will also conduct further plant specific analysis to determine whether this tradeoff would be in the ratepayers' interest.

Staff concluded in its initial comments that Idaho Power's 2011 IRP, by virtue of its September 20, 2011 presentation to the Commission, provides an evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations. Following initial comments, Staff received and evaluated the Company's responses to data request 42. The data request responses included a confidential spreadsheet presenting a breakdown of environmental compliance costs, by coal fired generation unit. The responses also included a confidential spreadsheet calculating the revenue requirement and resulting cost per megawatt-hour (MWhr) used in the evaluation presentation to the Commission. This spreadsheet aggregates the costs for all the Company's coal fired generation resources. In its review of the data request confidential spreadsheets, Staff found that Idaho Power considered and analyzed the suite of environmental compliance cost elements that are known and reasonable to consider at this time. Staff observes that the coal fired generation resource evaluation presentation and responses to data requests support continued use of the existing coal resources. Staff concludes that, for the present time, there is sufficient evidence supporting continued use of the Company's existing coal fired resources as part of a resource strategy with the best combination of cost and risk for Idaho Power and its ratepayers. This conclusion forms the basis for considering other action items in Idaho Power's 2011 IRP in more detail.

Staff recommends that Idaho Power be required to further investigate whether there is flexibility in the emerging environmental regulations that would allow the Company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives. In addition, Staff recommends that Idaho Power conduct further plant specific analysis to determine whether this tradeoff would be in the ratepayers' interest. Staff recommends that the Company be required to provide this additional analysis in their 2011 IRP Update.

b. Resolution

We agree with Staff that the September 20, 2011 coal fired generation resource evaluation presentation made by the Company advances the economic analysis of coal plant replacement. However, we view this evaluation as a proof-of-concept analysis. We do not find that the evaluation has been fully vetted, and agree with Staff that there should be further review of the modeling, and further investigation and analysis of the potential for flexibility in the emerging environmental regulations.

All of our acknowledgement decisions in this IRP are influenced by the uncertainty surrounding Idaho Power's coal fleet. We precede with the remaining acknowledgment decisions in this case, relying on the preliminary result from the coal fired generation resource evaluation presentation, because we expect Idaho Power to complete additional evaluation and file it with the upcoming IRP Update in 2012. If the results of the additional evaluation in the IRP Update are significantly different from the preliminary results, then the Company can ask us to consider these acknowledgment decisions again at that time. The following action item is added:

> Action Item 11 - Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants
>
> In its next IRP Update, Idaho Power will include an Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants. The Evaluation will investigate whether there is flexibility in the emerging environmental regulations that would allow the Company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives. The Company will also conduct further plant specific analysis to determine whether this tradeoff would be in the ratepayers' interest.

2. Boardman to Hemingway Transmission Project (Action Item 7)

a. Parties' Positions

Initial Comments:

RNP commented it generally supports acknowledgment of the primary resource in Idaho Power's near-term 10-year portfolio: improved access to markets through development of the Boardman to Hemingway transmission line (B2H). RNP goes on to state that meeting summertime peak capacity needs with market purchases from the winter-peaking west appears to be a solid plan for the utility, and B2H also brings strong reliability benefits. B2H, RNP believes, can also position Idaho Power to acquire more energy from renewable resources, and lower the cost of integrating renewables by enabling access to within-hour flexibility now developing in the broader market.

CUB commented that things would change if some of Idaho Power's coal units were phased out; noting the preferred Action Plan assumes the addition of the Boardman to Hemingway transmission line. CUB points out, if one or more of the coal units were to close, some transmission lines would have open capacity. Thus, the design and location of new transmission could change with the closure of one or more coal plants.

In initial comments Staff noted it continues to review this project for consistency between the Capital Costs represented in the Company's 2011 IRP and in responses to Staff data requests. Furthermore, Staff continues to review the assumptions used in determining the economic net benefits and non-economic benefits of the B2H Project.

In general, Idaho Power concurred with the RNP's initial comments as they relate to the B2H transmission project. As for capital costs, the Company noted and appreciated Staff's review and verification of the anticipated costs and assumptions associated with the B2H project. As the project developer, Idaho Power continues to review its assumptions and costs on a regular basis to ensure the project complies with the Company's goals and objectives and continues to represent the best cost/risk resource.

In response to CUB's argument that coal plant closures would free up transmission capacity, Idaho Power noted that determining which existing transmission lines on its system could have additional free capacity as the result of a potential future shut-down of one of the Company's coal plants is highly speculative and inconsistent with prudent utility planning practices. As noted above, the Company stated it is premature in this IRP for the Company to conduct the detailed environmental compliance cost analyses requested by CUB. Moreover, once those analyses are complete, it is wholly unknown whether the results of those analyses will suggest early decommissioning and shut-down of the Company's coal plants is the least cost alternative. Accordingly, the Commission should not delay the B2H project to conduct the environmental compliance cost analyses called for in CUB's comments. Idaho Power suggested the Commission should acknowledge B2H as the Company's preferred portfolio resource as the Company has demonstrated in its 2011 IRP that is the most cost-effective way to meet the resource needs of the Company and its customers.

Staff Final Comments:

Revised Action Item

Staff recommends acknowledging the B2H transmission project with the requirement for Company analysis updates, as follows:

> Action Item 7 - Transmission – ACKNOWLEDGED WITH REQUIREMENT FOR ANALYSIS UPDATES. Continue to make progress on the Boardman to Hemingway transmission project between now and the completion of the 2013 IRP, and plan to begin work on permitting and initial designs shortly after the completion of the 2013 IRP.
>
> As the Company proceeds with the B2H project, its project assumptions (for example, construction cost estimates, equity partnership estimates, third-party subscription estimates, and wheeling revenues) will be updated and analyzed in the 2013 IRP.

In regard to CUB's comment that the design and location of new transmission could change with the closure of one or more coal plants, Staff notes that the only coal fired resource in the vicinity of the B2H transmission project is Portland General Electric's Boardman plant, and that plant is assumed in this IRP to be shut down in 2020. As a result, in relation to the B2H project, there is no additional transmission capacity to be freed-up by coal plant retirements. Staff therefore does not recommend directing Idaho Power to delay the B2H project while completing the requested coal plant evaluation. Staff does recommend Idaho Power evaluate the B2H project in light of the findings of the coal plant evaluation to ensure optimal benefits and timing before moving forward with permitting and construction.

Staff generally agrees with the comments offered by RNP and CUB regarding the benefits the B2H transmission project brings. Staff typically conducts its analysis of transmission projects on the basis of quantifying the costs and benefits of the project. The B2H project, however, is proposed and justified as the primary resource in a portfolio representing the best combination of cost and risk for Idaho Power and its ratepayers. On that basis Staff evaluated the B2H project, as described below.

Idaho Power included the B2H project in its 2011 IRP Preferred Resource Portfolio.[2] The proposed B2H project involves constructing, operating, and maintaining a new single-circuit 500-kV transmission line of approximately 300 miles in length. The

[2] See Idaho Power's 2011 IRP, Chapter 1, "Summary," "Table 1.1," page 7.

proposed route is between northeast Oregon and southwest Idaho.[3] The project's capital cost is estimated by the Company to be approximately $820 million.[4,5]

Double Counting of Allowance for Funds Used During Construction (AFUDC)

In Idaho Power's response to Staff data request 27,[6] the Company provided an estimated capital cost of approximately $820 million, inclusive of approximately $93 million in AFUDC. Assuming a 28 percent share, the Company estimated its portion of the project's capital costs at $229 million (28 percent of $820 million). However, in addition to the AFUDC included in the Company's estimated portion of $229 million, the Company also included $31 million of AFUDC to arrive at $260 million as calculated in Idaho Power's Attachment 1 to the Company's response to Staff Data Request 28.[7] Therefore, $31 million in AFUDC was double counted.

Staff addressed this double counting in Staff data request 48.[8] In Idaho Power's response, the Company represented that "[t]he Public Utility Commission of Oregon Staff is correct in that AFUDC was mistakenly included twice in the capital cost estimate for B2H in the IRP." In the same response to Staff data request 48, the Company updated the present value of revenue requirement (PVRR) of the B2H project to address the double counting, reducing it by $38 million from $316 million to $278 million.[9]

Conclusion

Commission Order No. 10-392, related to the Company's 2009 IRP, noted the small number of recent transmission projects and the case specific nature of any transmission project, make it difficult to vet key assumptions that will determine the cost to Idaho Power's retail customers of the B2H project. The Commission also noted its concern about this uncertainty was tempered by risk analyses showing that the "B2H portfolio" is the best portfolio for customers over a range of capital costs and third-party subscription levels. Accordingly, the Commission considered it reasonable to proceed with the B2H project based on the information available at that time. In that Order, the Commission also adopted Staff's recommendation that Idaho Power be required to update its B2H project assumptions (for example, construction cost estimates, equity partnership estimates, third-party subscription estimates, and wheeling revenues) in its 2011 IRP. At the Commission public meeting on September 7, 2010, the Company committed to continue to analyze and assess the B2H project as an uncommitted resource.

Staff has the same concerns with regard to the B2H transmission project in this 2011 IRP as it did in the 2009 IRP. As done by the Commission for the 2009 IRP, Staff

[3] See Idaho Power's 2011 IRP, Chapter 5, "Supply-Side Resources," page 51.
[4] See Idaho Power's 2011 IRP, Chapter 5, "Supply-Side Resources," "Updated Cost Estimate," page 53.
[5] See Idaho Power's response to Staff Data Request 27.
[6] See Idaho Power's response to Staff Data Request 27.
[7] See Idaho Power's response to Staff Data Request 28.
[8] See Idaho Power's response to Staff Data Request 48.
[9] The reduction of approximately $38 million in PVRR is the equivalent of reducing $31 million of the project capital costs.

tempers its concern with recognizing the project continues to be identified, through the 2011 IRP analysis, as the primary resource in the best portfolio for customers over a range of capital costs and third-party subscription levels. On this basis, Staff recommends the B2H project be acknowledged, but that as the Company proceeds with the B2H project, its project assumptions (for example, construction cost estimates, equity partnership estimates, third-party subscription estimates, and wheeling revenues) should be updated.

b. Resolution

We share the concerns noted by Staff related to confirming the cost of the B2H project to customers. However, we consider it reasonable to proceed with the B2H project based on the information available now. As a result, we acknowledge B2H with the requirement for Company analysis updates. Action Item 7 is revised as follows:

> Action Item 7 - Transmission – <u>ACKNOWLEDGED WITH REQUIREMENT FOR ANALYSIS UPDATES</u>. Continue to make progress on the Boardman to Hemingway (B2H) transmission project between now and the completion of the 2013 IRP, and plan to begin work on permitting and initial designs shortly after the completion of the 2013 IRP.
>
> <u>As the Company proceeds with the B2H project, its project assumptions (for example, construction cost estimates, equity partnership estimates, third-party subscription estimates, and wheeling revenues) will be updated and analyzed in the 2013 IRP.</u>

3. Conservation Voltage Reduction (Action Item 4)

a. Parties' Positions

Initial Comments:

Staff reported in its initial comments that in the response to Staff data request 45 Idaho Power stated:

> The Idaho Power results from this [Northwest Energy Efficiency Alliance 2007 Distribution Efficiency Initiative] study show that a voltage reduction of approximately 3 percent results in energy savings of approximately 1.5 percent to 2.5 percent and approximately 1.8 percent to 2.6 percent on peak, 80 percent to 90 percent of this savings are on the customer side of the meter.

In its response the Company also noted that:

> CVR [conservation voltage reduction] was implemented on 30 circuits in 2009. Estimated annual savings for these circuits is 5,665 megawatt-hours

("MWh") and 0.78 megawatts ("MW") during peak load periods. For 6 of the 9 circuits scheduled for implementation by the spring of 2012, the estimated annual savings is 4,110 MWh and 0.82 MW on peak load periods.

Staff went on to comment that, despite these promising beginnings for CVR measures, neither Idaho Power's IRP nor its Appendix B on Demand-Side Management mentions further plans for CVR. Nor are the savings from potential CVR measures incorporated in its supply-demand balance for energy or peak demand. As a result, Staff was considering an additional action item to address acquisition of cost effective CVR resources.

Idaho Power stated in its reply comments that it had thoroughly considered both the potential and cost effectiveness of CVR. Accordingly, there was no need for the Commission to issue an additional action item addressing the acquisition of cost effective CVR.

The Company also stated most of the savings realized by Idaho Power from CVR occurred in the years prior to the 2011 IRP planning horizon and subsequently the savings were not considered a new resource. As stated in response to Staff's data request 43 in this proceeding, CVR impacts are indirectly integrated into the load forecast by virtue of being embedded in the historical data that is used as part of preparing the load forecast. Mathematically, the impact is effectively being attributed to other variables such as codes, manufacturing standards, weather, economy, and trend or error.

Lastly, as for cost effectiveness, Idaho Power commented it had done some preliminary analysis that showed the projects the Company had completed to be very cost-effective as there was little or no cost. As Idaho Power explores further circuits that require more investment to enable CVR to be effective, the cost-effectiveness will have to be more closely examined.

Staff Final Comments:

Revised Action Item

For the reasons reported in its initial comments, Staff recommends an additional action item to address acquisition of cost effective CVR resources, as follows:

Action Item 4 – Conservation Voltage Reduction - The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The Company will propose an action plan in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's supply-demand balance forecasts.

Staff respectfully disagrees with the Company's statement that:

> CVR impacts are indirectly integrated into the load forecast by virtue of being embedded in the historical data that is used as part of preparing the load forecast. Mathematically, the impact is effectively being attributed to other variables such as codes, manufacturing standards, weather, economy, and trend or error.[10]

Staff sees this statement is logically incorrect. The Company agrees that there is an untapped CVR and that this resource is "very cost effective."[11] The Company indicates it is pursuing further reductions in load from continued implementation of CVR.[12] Mathematically, these future reductions in the need will affect the need for resource additions and are not included in the IRP.

Conclusion

Staff re-affirms its initial comments and proposes that the addition of a CVR action item be part of the Commission acknowledgement of the IRP in this docket.

b. Resolution

We are moved by Staff's comment that, despite these promising beginnings for CVR measures, neither Idaho Power's IRP nor its Appendix B on Demand-Side Management mentions further plans for CVR. Nor are the savings from potential CVR measures incorporated in its supply-demand balance for energy or peak demand. We are convinced, as was Staff and Idaho Power, that there is an untapped CVR resource and that this resource is "very cost effective."As a result, we direct the addition of a CVR action item as follows:

> Action Item 4 – Conservation Voltage Reduction - The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The Company will propose an action plan in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's supply-demand balance forecasts.

4. Demand Response (Action Item 3)

a. Parties' Positions

Initial Comments:

Staff's initial comments noted that in both the September 20, 2011 presentation made to the Commission and the workshop held that afternoon, the Company presented

10 Company Reply Comments of Nov. 8, 2011 at 11.
11 Ibid at 12.
12 Ibid.

an analysis comparing the cost per megawatt-hour for the various demand response (DR) programs with that for a simple cycle combustion turbine (SCCT). Staff does not necessarily question the underlying analysis or results. Staff saw the basis for DR programs being that the cost of not using capacity is substantially less than the cost of generating capacity. On that basis, if the cost of DR programs was more than the cost of an SCCT, Staff would believe the DR program implementation may need revision. Staff reported it would continue to investigate this concern.

Staff Final Comments:

Based on Page 41 of 2011 IRP the goal of demand response programs at Idaho Power is to reduce summer peak load during periods of extremely high demand and minimize or delay the need to build new supply-side resources. The Company indicates that in this IRP cycle the evaluation of demand response programs was switched from an "all cost-effective DSM" approach to a "need-based" approach. An analysis conducted as part of Idaho Power's 2011 IRP concluded that for Idaho Power there is a defined optimal amount of demand response for Idaho Power's system. In its analysis the costs from an energy perspective for demand response were compared to the energy costs of owning and operating an SCCT. The appropriate level of demand response should not be determined based on a comparison of the cost per hour of demand response to the hourly cost of energy produced in a simple cycle combustion turbine. Staff contends that this type of analysis contradicts the Company's own statement regarding why demand response is needed, to offset the need for new capacity resources, and therefore such a comparison is inappropriate and potentially misleading. In its filing, the Company confirms that demand response is less expensive than a SCCT from a capacity perspective, which is how program cost-effectiveness is determined.

In Staff's final comments it presents a table reporting the Company's historical and projected levels of peak hour load reduction due to demand response. Between 2008 and 2010 the Company increased the amount of demand response by more than a factor of five.

Growth in summertime peak-hour demand continues to drive the Company's need for additional resources. The avoided capacity resource for peak summer hours and for demand response programs is based on a 170 MW natural gas fired, simple-cycle combustion turbine. The marginal resource the Company is trying to avoid with DSM efforts for summer on peak is a SCCT. The estimated levelized capacity cost of building a new SCCT is $94/kW over 30-year expected life. For DR or direct load control, DSM programs operating during summer peak, the $94/kW becomes the cost threshold for program cost effectiveness. The Company indicates that in 2030, the projected 351 MW of demand response has a levelized cost of $48/kW.

Conclusion

Staff recommends that the Company pursue all cost effective demand response through existing programs (Irrigation Peak Rewards, A/C Cool Credit and FlexPeak

Management) and consider new programs as applicable, including those using third-party program administrators and those that would extend into September when peak management is also an issue. In the long term planning horizon, the Company should continue to consider how demand response could offset need for new resources and how current seasonal limitations could be overcome through modified program design. The Company should pursue all the demand response it can in order to both offset need for supply side resources, and if properly designed, to offset the need for market purchases in peak periods.

Staff questions whether or not the Company needs to identify an optimum level of demand response as it indicates the Company is now doing. The Company's first attempt to demonstrate this optimum level by comparing hourly energy costs of demand response to hourly energy costs of an SCCT is not convincing and simply does not make sense. If there is an optimum, the Company has failed to convince Staff. Staff continues to believe Demand Response is the least cost, least risk resource, so it should be maximized.

b. Resolution

We agree with Staff that the Company pursue all cost effective demand response through existing programs and consider new programs as applicable, including those using third-party program administrators and those that would extend into September when peak management is also an issue. No revision to Action Item 3 is ordered.

> Action Item 3 - Demand Response - The levels of demand response determined for the 2011 IRP analysis is 330 MW for summer 2011, 310 MW in 2012 when the Langley Gulch plant comes on line, and 315 MW in 2013 and 2014. In 2015, the demand response level used in the IRP analysis is 321 MW and then 351 MW from 2016 through the end of the planning period.

5. Energy Efficiency (Action Items 1 and 2)

a. Parties' Positions

Initial Comments:

Staff's initially commented it was evaluating whether Idaho Power's approach and effort captures, and will continue to capture, all cost effective energy efficiency.

Staff Final Comments:

The Company's IRP pointed out that energy efficiency also results in peak reduction. Currently, cost effectiveness of existing and new energy efficiency programs is high. Idaho Power is pursuing 42 aMW of new energy efficiency load impact by 2030, at a total resource cost benefit cost ratio of 3.2, a total resource levelized cost of $0.051/kWh and utility levelized cost of $0.026/kWh.

Conclusion

Staff recommends the Company continue to pursue all cost effective demand side management as the lowest cost resource for customers.

b. Resolution

We agree with Staff that Idaho Power should continue to pursue all cost effective demand side management. No revision to Action Items 1 and 2 are ordered.

> Action Item 1 - Current Portfolio Energy Efficiency - In 2015, the forecast reduction for 2011–2015 programs will be 69 aMW; by the year 2020, the reduction across all customer classes increases to 133 aMW. By the end of the IRP planning horizon in 2030, 191 aMW of reduction is forecast to come from the current energy efficiency portfolio, with 80 percent of that reduction coming from programs serving commercial and industrial customers.
>
> Action Item 2 - New Portfolio Energy Efficiency - In 2015, the new and expanded energy efficiency programs will reduce average loads by 13 aMW; in 2020, average loads will be reduced by 25 aMW. The full 20-year capacity of the program additions and changes is 42 aMW of average demand reduction.

6. Alternative Portfolio (Action Items 8 and 9)

a. Parties' Positions

Initial Comments:

RNP encouraged the Commission to seriously consider alternatives to acknowledging Idaho Power's alternative resource portfolio (1-4 SCCT), which is comprised solely of single cycle combustion turbine plants. Before acknowledging an all-gas alternative, RNP recommends the Commission give demand side management ("DSM") alternatives and solar photovoltaic ("solar PV") resources as much time as possible to ripen, because pursuing those alternatives to lowering peak needs could provide greater long-term benefits to the utility and its customers.

Staff Final Comments:

<u>Revised Action Item</u>

Staff recommends the alternative resource portfolio not be acknowledged as part of this IRP.

Action Item 8 - Solar – NOT ACKNOWLEDGED AS PART OF THIS IRP ~~as described for the preferred portfolio.~~

Action Item 9 - Simple Cycle Combustion Turbine – NOT ACKNOWLEDGED AS PART OF THIS IRP ~~170 MW in 2015, 170 MW in 2017, and 94 MW in 2019. If the Boardman to Hemingway transmission project is delayed, begin the acquisition process for the 2015 SCCT as early as 2012.~~

Conclusion

Staff agrees with RNP, but for different reasons, that the alternative resource portfolio should not be acknowledged. Idaho Power proposes the alternative portfolio as its plan should the Boardman to Hemingway transmission project be delayed. Staff finds there are mechanisms available within the existing IRP process to deal with unforeseen circumstances, such as a delay in acquisition of a major resource. The primary mechanisms are the IRP Updates and new IRPs on a two year cycle. Given existing mechanisms to deal with a delay in the B2H project, Staff does not recommend acknowledging the alternate resource portfolio.

b. Resolution

We agree with Staff that there are existing mechanisms in the IRP process to address unforeseen circumstances, and therefore do not find a need to acknowledge an alternate resource portfolio. As a result, the associated action items are revised as follows:

Action Item 8 - Solar – NOT ACKNOWLEDGED AS PART OF THIS IRP ~~as described for the preferred portfolio.~~

Action Item 9 - Simple Cycle Combustion Turbine – NOT ACKNOWLEDGED AS PART OF THIS IRP ~~170 MW in 2015, 170 MW in 2017, and 94 MW in 2019. If the Boardman to Hemingway transmission project is delayed, begin the acquisition process for the 2015 SCCT as early as 2012.~~

7. Long-Term Action Items (Action Item 12)

a. Parties' Positions

Staff Final Comments:

Revised Action Item

Staff recommends the long-term action items not be acknowledged as part of this IRP.

Action Item 12 – Long-Term Action Items – NOT ACKNOWLEDGED AS PART OF THIS IRP ~~as outlined in IRP Table 10.2~~

Idaho Power's long-term action items cover actions in the 2021 through 2030 time period. Staff takes no issue, at this time, with the content of the long-term action items. Staff does find that IRP Guideline 4(n) calls for an action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources.

Conclusion

Because of the desired focus in IRP Guideline 4(n) on actions over the next two to four years, Staff does not recommend acknowledging the long-term action items.

b. Resolution

We agree with Staff that the desired focus in IRP Guideline 4(n) is on actions over the next two to four years. As a result, we do not find a need to acknowledge the long-term action items. The long-term action items are not acknowledged, as reflected in the following action item revision.

Action Item 12 – Long-Term Action Items – NOT ACKNOWLEDGED AS PART OF THIS IRP ~~as outlined in IRP Table 10.2~~

8. Load Forecast

a. Parties' Positions

Initial Comments:

Staff's initial comments reported concern that Idaho Power's assumption of 1.4 percent average-energy growth and 1.8 percent peak-hour load growth were too high. Staff based its initial concerns on the lingering economic recession, plus a shift occurring in the demand/supply balance: a demand-side shift from increased conservation success; and a supply-side shift by increasingly stringent environmental regulation. Staff would consider as reasonable a growth rate nearer the Energy Information Administration (EIA) expectation that electricity demand will grow at one percent (or less) through 2035. In addition, Staff was concerned the Idaho Power average-energy and peak-hour forecast deficit is premature by approximately two years. Staff would expect a peak-hour monthly deficit (with existing DSM and resources) near 2017 and an average-energy monthly deficit (with existing DSM and resources) near 2018.

As another component of the load forecast review, Staff commented that it looks forward to the upcoming Load Update (at the end of October, 2011). Staff was especially interested in the current status of the Hoku Materials load, the status of the contract with the new large Oregon customer (60-80 aMW), and the irrigation sector modeling. Finally, Staff commented it would continue to evaluate the load forecast in the context of the range presented in the IRP.

In reply comments the Company stated it was important to note that, for IRP planning purposes, Idaho Power must pick a point in time and, based upon the best information available at that time, the Company must develop assumptions to be used in the IRP. In the case of the 2011 IRP, Idaho Power used all information available as of July 2010 to develop its load forecast. Idaho Power admitted that the current national economic slowdown was having an impact on its load forecasts. Notwithstanding, the Company sought acknowledgement of its 2011 IRP based upon the best information available at the time the IRP was developed. In addition, Idaho Power disagreed with Staff that using broad, industry-wide, national data, such as the EIA load forecast, was appropriate for the Company's IRP planning process. Idaho Power conducted detailed, service area-specific analyses based on historic and forward looking data to develop its load forecast. Accordingly, the Company suggested the Commission should rely on the Company's load forecast data in acknowledging the Company's 2011 IRP.

Staff also noted that IRP page 8 discusses what Idaho Power calls "New Large Loads." Staff commented it was evaluating this issue in the context of whether it is appropriate, from a cost and ratemaking perspective, to include potential new large loads in IRP load forecasting. Staff's initial thinking was that, if it is appropriate, allowance for new large loads could be included in the additional firm load category, as was proposed for the Special Customer (IRP page 63-64). Staff will continue to evaluate and consider this issue.

Staff Final Comments:

Staff agrees with Idaho Power that, for IRP acknowledgement purposes, it is not appropriate to pick-and-choose selected items. Staff also desires to evaluate the complete forecast process. Idaho Power acknowledges that the current national economic slowdown is having an impact on its load forecast (Page 9 of the Company Reply Comments). Staff is concerned about basing its recommendations on a July 2010 forecast that has proven to be inaccurate. Staff final comments present a table showing the historical picture of Idaho Power's performance in the state of Oregon (from 2010 Oregon Statistics Book). The table shows an actual load growth of 0.05 percent over the 2001 to 2010 time period. This is substantially less than the 1.4 percent average-energy growth forecast by Idaho Power for this IRP. Although the IRP analysis considers a range of load growth forecasts from 1 to 1.8 percent, the 0.05 percent actual load growth since 2001 is outside the range considered. However, the one percent load growth suggested by Staff is within range considered in the IRP.

Conclusion

Recognizing the Company near-term action plan does not request acknowledgement of new supply side resource acquisition, but rather acknowledgement to continue to make progress on the B2H project, Staff does not recommend a change to the 2011 IRP based on an updated load forecast. Instead, Staff highlights the need for the

2011 IRP Update and the 2013 IRP to be based on an updated load forecast that, as accurately as possible, reflects current conditions.

Related to the new large load issue introduced in its initial comments, Staff concludes it is appropriate to include an allowance for new large loads in the load forecast as an additional firm load category, but the new large load must be based on specific supporting documentation.

b. Resolution

We agree with Staff that the 2011 IRP Update and the 2013 IRP need to be based on an updated load forecast that, as accurately as possible, reflects current conditions. We also concur that it is appropriate to include an allowance for new large loads in the load forecast as an additional firm load category based on specific supporting documentation.

9. Risk Analysis

a. Parties' Positions

Initial Comments:

Staff noted its concern whether the approach Idaho Power used, whereby it sampled from a uniform distribution of incremental costs associated with each risk variable, resulted in a meaningful risk analysis.

Staff also reported considering a recommendation to include hydro generation variability as a risk variable/factor for the next IRP cycle. Staff based this recommendation on recognizing Idaho Power's significant reliance on hydroelectric generation, and the IRP Guideline 1(b)1 listing hydroelectric generation as a source of risk and uncertainty that should be addressed.

Staff Final Comments:

Staff finds two troubling aspects to Idaho Power's stochastic risk analyses – particularly as the Company's analyses are contrasted with the more conventional approaches used by other Oregon utilities:

1. Rather than ascribing standard normal or lognormal statistical distributions to the risk factors, the Company sets a year-by-year upper and lower limit to each of the factors.

2. The purpose of stochastic risk analysis is, in particular, to obtain estimates of upper limits (e.g., 90th percentile) to the multi-year revenue requirements associated with the various portfolios. Generally, this task is accomplished by randomly varying the risk factors on a year-by-year basis and calculating what the

revenue requirement (or "sample value") would be each year given the values of those risk factors.

Idaho Power's approach is "totally" different. How a single revenue requirement "sample value" for a given year is obtained is described as follows:

a. While holding all other risk factors at their base values, the Company calculates the highest and lowest revenue requirement that would come forth after taking a particular risk factor's extreme upper and lower limits as described in 1., above.

b. The revenue requirement range just developed is divided into five equal-sized parts, with five "values" comprising the mid-points of those parts.

c. One "value" for the revenue requirement is chosen, with each of the five values from b. being given an equal chance of being chosen.

d. a. b. and c. are repeated for all the other risk factors, yielding a total of six "values" (where six is the number of different risk factors considered).

e. The "sample value" for the year is the average of those six individual "values."

The following consists of a simplified example contrasting the PacifiCorp and Idaho Power approaches to calculating a particular year's revenue requirement for a given portfolio:

1. Assume just two risk factors, gas prices and load growth.

2. A single "sample value" under the more standard approach described above might, for example, be what the revenue requirement would be if the gas price was "drawn" as a particular low value from a lognormal distribution, and the load was "drawn" as something above average from a normal distribution.

3. By contrast, Idaho Power's comparable "sample value" would be the average of two revenue requirements, where one was "drawn" from the five equal-sized array of revenue requirements where only gas prices varied and the other was "drawn" from the similar array where only the load varied. So, what you will end up with is a revenue requirement that represents at once a likely deviant and the nominal value for each of the risk factors. A revenue requirement distribution thus derived is difficult to interpret compared to conventional revenue requirement distributions that are based on coherent combinations of risk factors.

Staff sees the basic problem with the approach used by Idaho Power (besides the uniform distribution assumptions) is that an adverse combination of two or more unfavorable risk factors will never be "sampled" because only one risk factor is allowed to depart from its base value for any one “draw.” Staff concludes that the stochastic risk analyses of Idaho Power do not provide reliable information in evaluating the risk dimension of the cost-risk analysis.

Staff also confirms its recommendation to include hydro generation variability as a risk variable/factor for the next IRP cycle. As stated in initial comments, Staff bases this recommendation on recognizing Idaho Power’s significant reliance on hydroelectric generation, and the IRP Guideline 1(b)1 listing hydroelectric generation as a source of risk and uncertainty that should be addressed.

Conclusion

Staff recommends the next Idaho Power IRP should present risk analysis results based upon the more conventional approach described above. This recommendation does not preclude the Company from simultaneously presenting results based upon the methodology used in the current IRP. Specifically:

1. Rather than simply estimating upper and lower extreme values for the various risk factors, statistical distribution functions should be estimated. Also, when risk factor values are randomly drawn from those distributions, how the risk factors correlate with themselves on a year-by-year basis and, in a given year, with each other (if at all) should be taken into consideration – i.e., conditional distribution functions should be employed.

2. Calculate a sample year’s single revenue requirement for a particular portfolio by simultaneously employing all of the risk factor values that were randomly drawn for that year. That year’s value will combine with the single revenue requirement values for all the other subject years to yield a single net-present-value revenue requirement (NPVRR) for the subject (ten- or twenty-year) period. Repeating that process one hundred times will establish the distribution of NPVRRs for the given portfolio, and from that distribution can be obtained the median NPVRR and the upper-tail values.

In addition, Staff recommends including hydro generation variability as a risk variable/factor for the next IRP cycle.

b. Resolution

We are convinced by Staff’s comments that the next Idaho Power IRP should present risk analysis results based upon the more conventional approach Staff describes above. We also note this recommendation does not preclude the Company from simultaneously presenting results based upon the methodology used in its 2011 IRP. Lastly, we agree with Staff that Idaho Power include hydro generation variability as a risk variable/factor for the next IRP cycle.

10. Wind Integration Study

a. Parties' Positions

Initial Comments:

RNP stated its understanding that Idaho Power was conducting a wind integration study internally. It encouraged Idaho Power to look for ways in which diversity and flexible balancing resources could lower its cost of integrating what has been recognized as a low cost energy resource (see 2011 IRP, p. 83). RNP also encouraged Idaho Power to seek both independent technical review of its study and to provide meaningful opportunity for stakeholders to give, and the utility to respond to, feedback on the study's methodology and results before those results are folded into the next IRP analysis.

Staff noted that Idaho Power was in the early stages of its wind integration study.

Staff Final Comments:

Staff agrees with RNP that Idaho Power's should seek independent technical review of its wind integration study and meaningful opportunity for stakeholders to give feedback, before incorporating the study results into the next IRP.

Given that Idaho Power is in the process of preparing its wind integration study, Staff does not recommend redirecting that study to, as suggested by RNP, consider ways in which diversity and flexible balancing resources could lower its cost of integrating intermittent resources. Staff notes that wind integration studies to date have been designed to identify the cost of using existing resources to integrate intermittent resources. Staff sees the next generation of wind integration studies as the appropriate venue to explore and develop analytical techniques for identifying and evaluating methods for reducing the cost of integrating intermittent resources.

Conclusion

Staff recommends Idaho Power seek independent technical review of its wind integration study and meaningful opportunity for stakeholders to give feedback, before incorporating the study results into the next IRP. In addition, Staff recommends the Company's next wind integration study look for ways in which diversity and flexible balancing resources could lower its cost of integrating intermittent resources.

b. Resolution

We appreciate RNP's devotion to improving studies and processes for integration of intermittent resources. After considering the points made by RNP and Staff, we are persuaded it is a reasonable path forward to direct that Idaho Power seek independent technical review of its wind integration study and meaningful opportunity for stakeholders to give feedback, before incorporating the study results into the next IRP. In addition, the Company's next wind integration study should look for ways in which diversity and flexible balancing resources could lower its cost of integrating intermittent resources.

11. Other

a. Parties' Positions

Initial Comments:

Solar PV Resource

RNP encouraged Idaho Power, as it gains experience with solar PV through its demonstration project and Oregon solar capacity standard project, not to limit its evaluation only to the performance of single projects. RNP stated its belief that geographic dispersion of several solar projects could have a significant effect on smoothing the short-term variability of single projects.

Capacity Planning Margin

Staff noted the process described on IRP pages 115 and 116 for back-calculation of a capacity planning reserve margin, effectively comparing the difference between the 50^{th} and 70^{th} percentile hydroelectric water conditions. Staff intended to explore whether this approach was still appropriate given the water issues described on IRP pages 15 and 16. Staff also noted the overlap between the capacity planning reserve margin and the capacity benefit margin used in the loss of load expectation analysis.

Firm Market Purchases

Staff noted IRP page 68 discusses transmission capacity limitations. In that discussion, Idaho Power stated that it does not typically rely on imports from the Intermountain Region for planning purposes. Staff stated its intent to investigate these limitations to consider whether Idaho Power's practice of not relying on these imports was still valid.

Staff Final Comments:

Solar PV Resource

Staff notes and agrees with RNP's observations.

Capacity Planning Margin

Staff has no further comments or concerns related to this issue.

Firm Market Purchases

Idaho Power's response to Staff data request 52 presented a description of the limitations to relying on imports from the Intermountain Region, as discussed on IRP page 68. The Company stated:

> Idaho Power Company's transmission import capability from northern Nevada (262 megawatts ("MW")) only permits the import of Idaho Power's share of the Valmy Plant (262 MW). Therefore, additional power purchases on this path are substantially limited. Similarly, Idaho Power's share of the Bridger transmission system (711 MW) is full with the Company's share of the Jim Bridger Plant (711 MW). Idaho Power's market access from Montana is also limited (167 MW) and already fully subscribed with transmission service for network load customers and power purchases for native load service (167 MW).
>
> Transmission access from the Salt Lake City area has recently been upgraded with the addition of the Populus Substation and the two Populus-Terminal 345 kilovolt lines. However, the limiting factor as described in the 2011 IRP is the size of the summer peak load in the Salt Lake City area and the resources available to serve that load. The Utah area's summer peak load typically coincides with Idaho Power's summer peak. Compared to the summer peak generation capacity that is available in the Pacific Northwest, there is little surplus capacity in the Utah area for Idaho Power to reliably rely on to serve its summer peak loads.

Staff is satisfied the Company's response confirms the continuing applicability of its historical import limitation.

b. Resolution

We note Staff's final comments.

12. Adherence of the Plan to Integrated Resource Planning Guidelines

a. Parties' Positions

Initial Comments:

Among parties to this docket there was unanimous agreement that Idaho Power's 2011 IRP, as filed on June 30, 2011, did not comply with Guidelines 4(g) and 1(c) because it failed to provide a comprehensive evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations. IRP Guideline 4(g) requires the utility to identify key assumptions about the future, including assumptions about future environmental compliance costs. IRP Guideline 1(c) sets the primary goal of the IRP to be the selection of a portfolio of resources with the best combination of cost and risk for the utility and ratepayers. Without a comprehensive evaluation of these environmental compliance costs, parties commented it was not possible to determine whether any of the candidate resource portfolios meet this standard.

In response to this deficiency, Idaho Power, in its September 20, 2011 IRP presentation to the Commission, presented, at a very high-level, an evaluation of a range of costs that could potentially result if certain environmental regulations were implemented. That high level analysis demonstrated that, even if the Company were required to spend the estimated amount to comply with potential federal environmental regulations, the existing coal fired resources would still be less expensive than constructing replacement natural gas generation resources.

Staff Final Comments:

By providing the information presented to the Commission on September 20, 2011, Staff believes the Idaho Power 2011 IRP reasonably complies with the IRP Guidelines. Staff notes that Guideline 4a, which requires an explanation of how the utility met each substantive and procedural requirement, was not provided. Refer to Staff Final Comments Attachment 1, prepared by Staff, for a table presentation of compliance by Guideline.

Staff notes that IRP Guideline 4(n) asks for an action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources. Idaho Power's 2011 IRP includes a chapter presenting its action plan, but that action plan presentation does not include demand side resource action items, and it does not include a concise presentation of the action items. As a result, Staff had to extract action items from the Demand-Side Resources chapter and the Action Plan chapter text, and assign a number to each for ease of reference. Staff recommends future IRPs include a concise listing of action items for all resources and resource related activities, with each action item numbered.

b. Resolution

We agree with Staff that future Idaho Power IRPs should include a concise listing of action items for all resources and resource related activities, with each action item numbered.

In considering whether to acknowledge a resource plan, this Commission reviews the Plan for adherence to our Guidelines for resource planning. By providing the high-level environmental compliance cost analysis for its existing coal fired resources, we conclude that Idaho Power's 2011 IRP reasonably meets the Integrated Resource Planning Guidelines.

B. CONCLUSION

Jurisdiction

Idaho Power Company is a public utility in Oregon that provides electric service to the public as defined by ORS 757.005.

Idaho Power Company is a public utility subject to the jurisdiction of the Commission.

Idaho Power's 2011 Integrated Resource Plan, as modified in this order, reasonably adheres to the principles of resource planning set forth in Order No. 07-002 and should be acknowledged with the following requirements:

Requirement:

The 2011 IRP Action Items are ordered to be revised as follows:

Near-Term Action Plan (2011-2020)

Demand-Side Resource Action Items

Action Item 1 - Current Portfolio Energy Efficiency - In 2015, the forecast reduction for 2011–2015 programs will be 69 aMW; by the year 2020, the reduction across all customer classes increases to 133 aMW. By the end of the IRP planning horizon in 2030, 191 aMW of reduction is forecast to come from the current energy efficiency portfolio, with 80 percent of that reduction coming from programs serving commercial and industrial customers.

Action Item 2 - New Portfolio Energy Efficiency - In 2015, the new and expanded energy efficiency programs will reduce average loads by 13 aMW; in 2020, average loads will be reduced by 25 aMW. The full 20-year capacity of the program additions and changes is 42 aMW of average demand reduction.

Action Item 3 - Demand Response - The levels of demand response determined for the 2011 IRP analysis is 330 MW for summer 2011, 310 MW in 2012 when the Langley Gulch plant comes on line, and 315 MW in 2013 and 2014. In 2015, the demand response level used in the IRP analysis is 321 MW and then 351 MW from 2016 through the end of the planning period.

Action Item 4 – Conservation Voltage Reduction - The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The Company will propose an action plan in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's supply-demand balance forecasts.

Supply-Side Resource Action Items (Preferred Portfolio)

Action Item 5 - Solar - Issue a request for proposal (RFP) before the end of 2011 to design and construct a 500-kW–1-MW solar PV resource to be located in Idaho Power's service area. Evaluate proposals by mid-2012, and if a successful bidder is identified, file a request with the IPUC for a CPCN. If approved, have the facility on line as early as the end of 2012.

This solar resource will satisfy the State of Oregon's Solar PV Pilot Program requirement to build a 500-kilovolt (kV) solar PV project. Continue working with the OPUC to determine if this facility would have to be built in Oregon, which may impact the structure of the RFP.

Action Item 6 - Power Purchase Agreements - Complete 83 MW in market purchase from the east side of Idaho Power's system. The purchase is necessary to cover a summer peak-hour deficit in 2015 that exists before the Boardman to Hemingway line becomes available in 2016.

Action Item 7 - Transmission – ACKNOWLEDGED WITH REQUIREMENT FOR ANALYSIS UPDATES. Continue to make progress on the Boardman to Hemingway transmission project between now and the completion of the 2013 IRP, and plan to begin work on permitting and initial designs shortly after the completion of the 2013 IRP.

As the Company proceeds with the B2H project, its project assumptions (for example, construction cost estimates, equity partnership estimates, third-party subscription estimates, and wheeling revenues) will be updated and analyzed in the 2013 IRP.

Supply-Side Resource Action Items (Alternative Portfolio)

Action Item 8 - Solar – NOT ACKNOWLEDGED AS PART OF THIS IRP ~~as described for the preferred portfolio.~~

Action Item 9 - Simple Cycle Combustion Turbine – NOT ACKNOWLEDGED AS PART OF THIS IRP ~~170 MW in 2015, 170 MW in 2017, and 94 MW in 2019. If the Boardman to Hemingway transmission project is delayed, begin the acquisition process for the 2015 SCCT as early as 2012.~~

Other Action Items

Action Item 10 - Renewable Energy Certificate Management - As detailed in the REC Management Plan, continue selling RECs in the near term until they are needed to meet a federal RES.

Action Item 11 - Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants

In its next IRP Update, Idaho Power will include an Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants. The Evaluation will investigate whether there is flexibility in the emerging environmental regulations that would allow the Company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives. The Company will also conduct further plant specific analysis to determine whether this tradeoff would be in the ratepayers' interest.

Long-Term Action Plan (2021-2030)

Action Item 12 – Long-Term Action Items – NOT ACKNOWLEDGED AS PART OF THIS IRP ~~as outlined in IRP Table 10.2~~

Effect of the Plan on Future Rate-making Actions

Order No. 89-507 set forth the Commission's role in reviewing and acknowledging a utility's least-cost plan as follows:

> The establishment of least-cost planning in Oregon is not intended to alter the basic roles of the Commission and the utility in the regulatory process. The Commission does not intend to usurp the role of utility decision-maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission….
>
> Acknowledgment of a plan means only that the plan seems reasonable to the Commission at the time the acknowledgment is given. As is noted elsewhere in this order, favorable rate-making treatment is not guaranteed by acknowledgment of a plan. *See* Order No. 89-507 at 6 and 11.

The Commission affirmed these principles in Docket UM 1056.[13]

This order does not constitute a determination on the rate-making treatment of any resource acquisitions or other expenditures undertaken pursuant to PacifiCorp's 2008 IRP. As a legal matter, the Commission must reserve judgment on all rate-making issues. Notwithstanding these legal requirements, we consider the integrated resource planning process to complement the rate-making process. In rate-making proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions which are consistent with acknowledged integrated resource plans. Utilities will also be expected to explain actions they take which may be inconsistent with Commission-acknowledged plans.

[13] *See* Order No. 07-002 at 24.

IV. ORDER

IT IS ORDERED that the 2011 Integrated Resource Plan filed by Idaho Power on June 30, 2011, is acknowledged in accordance with the terms of this order, and Order No. 07-002 as corrected by Order No. 07-047.

Made, entered, and effective ______________________________.

Susan Ackerman Commissioner	**John Savage** Commissioner
Stephen Bloom Commissioner	

LC 53
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CERTIFICATE OF SERVICE

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I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 6th day of December, 2011 at Salem, Oregon.

Kay Barnes

Kay Barnes
Public Utility Commission
Regulatory Operations
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