ATTACHMENT N-3
ORDER NO. 10-392 IN DOCKET LC 50

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 50

In the Matter of IDAHO POWER COMPANY 2009 Integrated Resource Plan.	ORDER

DISPOSITION: PLAN ACKNOWLEDGED WITH REQUIREMENTS

I. INTRODUCTION

Idaho Power Company (Idaho Power or Company) seeks acknowledgement of its 2009 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 Idaho Power's 2009 IRP and its preferred portfolio as presenting the best combination of expected costs and associated risks and uncertainties for the Company and its customers, and as satisfying the procedural and substantive requirements of this Commission. At the same time, we recognize that the assumptions for several key factors remain uncertain. For this reason, we require that Idaho Power perform further analyses in its 2011 IRP consistent with our discussion below.[2]

A. Requirements for Integrated Resource Planning

The Commission requires regulated energy utilities to prepare integrated resource plans within two years of acknowledgment of the last plan. Utilities must involve the Commission and the public in their planning process prior to resource decision-making.

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 to select a portfolio of resources with the best combination of

[1] The Commission originally adopted least-cost planning in Docket No. UM 180, *See* Order No. 89-507 (Apr 20, 1989). The Commission updated the least-cost planning process in 2007 in Docket No. UM 1056. *See* Order No. 07-002 (Jan 8, 2007).
[2] The original due date for the filing of the Company's 2009 IRP was June 2009. That date was extended by Commission order to December 2009. The Company will file its 2011 IRP in June 2011.

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 state and federal energy policies.[3]

B. Effect of Acknowledgement of an IRP on Future Ratemaking Actions

The Commission's role in reviewing an IRP is to determine whether the IRP meets the substantive and procedural guidelines in Order Nos. 89-507 and 07-002. The Commission generally does not address the need for specific resources, but rather determines whether the utility has proposed a portfolio of resources to meet its energy demand that presents the best combination of cost and risk.[4] Commission acknowledgement of an IRP means only that the Commission finds that the utility's preferred portfolio is reasonable at the time of acknowledgement.[5]

In Order No. 89-507, the Commission described its role in reviewing and acknowledging a utility's least-cost plan:

> 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.
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> 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.[6]

This order does not constitute a determination on the ratemaking treatment of any resource acquisitions or other expenditures undertaken in accordance with Idaho Power's 2009 IRP. As a legal matter, the Commission must reserve judgment on all ratemaking issues. Notwithstanding these legal requirements, we consider the integrated resource planning process to complement the ratemaking process. In ratemaking proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions that are consistent with acknowledged integrated

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[3] *See* Order No. 07-002.
[4] *See id.* at 25.
[5] *See id.* at 16.
[6] *See* Order No. 89-507 at 6, 11. The Commission affirmed these principles in Docket UM 1056. *See* Order No. 07-002 at 24.

resource plans. A utility is also expected to explain actions they take that are inconsistent with Commission-acknowledged plans.

C. Idaho Power's 2009 IRP

The Commission's IRP Guidelines state that a utility must file its IRP two years from the date of acknowledgement of the previous plan. Idaho Power received acknowledgement of its 2006 IRP on September 12, 2007.[7] Due to substantial changes in economic conditions and permitting delays for the Boardman to Hemingway 500 kV transmission project (B2H Project or Boardman to Hemingway), the Company requested a delay in its September 12, 2009 filing deadline. On May 26, 2009, the Commission approved Idaho Power's motion to delay its filing of the 2009 IRP until December 2009.[8] On December 30, 2009, Idaho Power filed its 2009 IRP.

This is Idaho Power's first plan under the Commission's newly adopted Guidelines.[9] In developing its 2009 plan, Idaho Power worked with an IRP advisory group comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, Commission representatives, and others.

Idaho Power's 2009 IRP analyses the potential cost of carbon emissions in two ways: cap-and-trade and carbon tax adders. While Idaho Power modeled both a cap-and-trade system and carbon tax adders in future scenarios, the Company primarily focuses on cap-and trade as the most likely regulatory outcome. The Company's analysis uses the Waxman-Markey Bill[10] as the basis for its assumptions on emission targets and allowances.

Idaho Power uses the AURORAxmp (AURORA) market model as the primary tool for determining future resource operations and to estimate the portfolio cost for the twenty-year IRP. Using the AURORA model, the Company performed a quantitative risk analysis of the following variables: third-party transmission subscription; renewable energy credit prices; natural gas prices; carbon emission costs; load growth; and conservation. Additionally, Idaho Power performed a qualitative risk analysis that looked at carbon regulation, technology, market risk, and resource siting.

For the first time, Idaho Power bifurcated the required twenty-year planning period into two ten-year planning periods—2010 through 2019 and 2020 through 2029. The Company believes that this approach prevents near-term decision making from being unduly influenced by resource decisions in the second ten-year planning period.

In the first ten-year planning period (2010 through 2019), Idaho Power examines four resource portfolios, classified as Solar, Gas Peaker, Gas Peaker and B2H,

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[7] *See* Order No. 07-394 (Docket No. LC 41).
[8] *See* Order No. 09-183 (Docket No. UM 1428).
[9] *See* Order No. 07-002.
[10] The Waxman-Markey Bill, named after its authors, Representatives Henry A. Waxman of California and Edward J. Markey of Massachusetts, was introduced as an energy bill in the 111th United States Congress. The bill was approved by the House of Representatives on June 26, 2009.

and B2H. The labeling of these portfolios defines the type of supply-side resource that would be used to meet Idaho Power's forecasted energy and capacity deficits. Originally evaluated in the Company's 2006 IRP, and common to all resource portfolios as "committed" resources, are (1) the Langley Gulch combined-cycle combustion turbine (CCCT), (2) up to 150 megawatts (MW) of wind generation, and (3) two 20 MW increments of geothermal energy coming on-line in 2012 and 2016.

In the second ten-year planning period (2020 through 2029), Idaho Power examines five resource portfolios. Idaho Power uses its preferred portfolio for the first ten-year planning period as the basis for designing the second period portfolios. The load forecast for the second planning period is relatively flat. The primary driver for new resources in the second period is carbon emission reductions due to coal curtailment, as identified in the Waxman-Markey Bill.

New energy efficiency programs included in the 2009 IRP are forecast to reduce annual load by 127 average MW (MWa) by the year 2029. This reduction represents a 53 percent increase over the measures included in the Company's 2006 IRP. New and expanded demand response programs are expected to reduce peak summer load by 323 MW by the year 2012, once the programs mature. This reduction represents significant growth over the 2006 IRP when demand response programs were estimated to provide only 78 MW of peak reduction by 2026. All estimated reductions in load due to energy efficiency and demand response programs are included in Idaho Power's 2009 load forecast.

Using an August 2009 load forecast, Idaho Power projects peak-hour load will grow at an average annual rate of 53 MW or 1.5 percent. Average system load is forecasted to grow by 13 MWa or 0.64 percent on an average annual basis over the twenty-year planning period. Idaho Power projects that its system will become short on capacity in 2013 and, on an energy basis, the system begins to experience a short position by 2014.[11]

Based on its analysis, Idaho Power selected "Portfolio 1-4 Boardman to Hemingway" as its preferred portfolio for the 2010-2019 planning period and "Portfolio 2-4 Wind and Peakers" as its preferred portfolio for the 2020-2029 planning period. The selection of these portfolios as the Preferred Portfolio for the twenty-year study is based on the Company's conclusion that the portfolios present the best combination of expected cost and associated risks.

The Company requests acknowledgement of an Action Plan to implement its Preferred Portfolio. The Action Plan includes the following items:

2010 Irrigation Peak Rewards program increases to 220 MW
FlexPeak Management program increases to 40 MW

[11] Idaho Power uses a 70th percentile water conditions and 70th percentile average load conditions for energy planning purposes. For peak-hour capacity planning, Idaho Power uses 90th percentile water conditions and 95th percentile peak-hour load.

2011 Irrigation Peak Rewards program increases to 250 MW
FlexPeak Management program increases to 45 MW

2012 Wind project on-line 150 MW
Langley Gulch CCCT on-line 300 MW
Geothermal Project on-line 20 MW

2013 Boardman to Hemingway construction begins
Shoshone Falls Upgrade Project construction begins

2015 Shoshone Falls Upgrade Project on-line 49 MW
Boardman to Hemingway completed for market purchases of 250 MW

2016 Geothermal Project on-line 20 MW

2017 Boardman to Hemingway capacity for market purchases of 175 MW

Finally, Idaho Power believes that the flexibility to adjust to changes during the present period of uncertainty regarding carbon regulation is very important.

II. DISCUSSION

A. Load Forecast

1. Parties' Positions

During a public comment hearing in Ontario, Oregon, on April 20, 2010, many commentators argued that the load forecast in Idaho Power's 2009 IRP is too high. Some of the reasons cited for this conclusion are: (1) the Company should not have included new large load customers; (2) the Company did not consider more recent load information in its forecast; and (3) based on historical housing start data, a more protracted economic recovery will occur than assumed by Idaho Power. Commentators believe that the Company over-projected its short-term load growth, making the Boardman to Hemingway transmission line appear necessary when, in fact, it is not needed in the time period specified by the Company.

In its reply comments, Idaho Power refutes all of the commentators' claims regarding its load forecast. The Company states that its forecast contains the most recent information available at the time the filing was prepared and, compared to the Northwest Power and Conservation Council (NPCC) forecast, Idaho Power's forecast is conservatively low. According to Commission Staff's comments, the NPCC's Sixth Power Plan average load forecast grows at an annual average rate of 1.96 percent, while Idaho Power's forecast grows at 1.4 percent over the twenty-year planning period. For peak-hour load, the NPCC forecast grows at an annual average rate of 2.13 percent, while Idaho Power forecasts its peak-hour load to grow at 2.02 percent.

Regarding the inclusion of large load customers in its forecast, Idaho Power states that large loads are developed through direct input from each of the Company's large load customers. These forecasted customer loads reflect the recession and other operational impacts on future energy use.

In its final comments, Staff agrees with the Company. After reviewing Idaho Power's analyses, Staff believes that the Company has conservatively forecasted its average-energy and peak-hour load, taking into consideration the recent economic downturn. But Staff notes that for the 2019 through 2029 planning period, Idaho Power forecasts average energy to grow at a rate of only 0.1 percent per annum, and peak-hour load growth of only 0.9 percent per annum. Staff is concerned that these growth rates may be too low, especially when the rate of growth in demand-side management (DSM) is projected to slow over this time period.

The inclusion of a customer response to potential price increases due to proposed carbon legislation is a contributing factor to relatively flat growth rates in the second ten-year planning period. Staff finds the customer response to projected price increases associated with carbon regulation to be an interesting change in the Company's forecasting methodology. Staff recommends that the Company provide further description of this analysis in future IRP planning cycles, including the regression coefficients and estimated price responsiveness of each customer class. In its final comments, Idaho Power supports Staff's recommendation.

In its final comments, the Oregon Department of Energy (ODOE) supports Idaho Power's load forecast estimates in its 2009 IRP. ODOE also supports the Staff comments associated with Idaho Power's load forecast and reiterates Staff's concerns about the load growth forecast beyond 2019.

2. Resolution

We agree with Staff's conclusion that Idaho Power's first ten-year load forecast is reasonable. We agree with Staff and ODOE that the projected load growth for the second ten-year period seems low. We adopt Staff's recommendation and require Idaho Power to justify its load forecast for the second ten-year period in future IRPs.

We also adopt Staff's recommendation that Idaho Power provide estimates of the price sensitivity for each of its customer classes and document the analyses underpinning those estimates in its next IRP planning cycle.

B. Preferred Portfolio for the First Ten-Year Planning Period and the Boardman to Hemingway Transmission Project

1. Parties' Positions

Idaho Power selected Portfolio 1-4 (Boardman to Hemingway) as its preferred portfolio for the 2010-2019 planning period. In comments on the IRP, Staff and intervening parties primarily focus on the selection of Portfolio 1-4 as the preferred portfolio versus the other portfolios and, more specifically, the inclusion of the Boardman to Hemingway transmission project. In its analysis, Staff examined the portfolio assumptions associated with the B2H Project, such as capital cost assumptions and third-party subscriptions. Staff evaluated the Company's approach to these variables and their robustness under changing circumstances (for example, higher construction costs or lower third-party subscription rates).

Staff notes that very few interstate transmission projects have been constructed in the region over the last 30 years. It is only recently that utilities in the west have proposed and started to build these large transmission projects, such as Gateway West, the Southwest Intertie, and others. Due to the more recent interest by utilities and consortiums in building these projects, Staff was unable to obtain a reliable set of benchmark data to compare to Idaho Power's cost assumptions and subscription rates. In addition, Staff notes that the cost components of an interstate transmission project can vary widely depending on the type of terrain and right-of-way costs. Thus, rather than attempting to compare these components side-by-side to another project, Staff examined how much these assumptions would have to change in order to make the Portfolio 1-4 no longer the best combination of cost and risk. Idaho Power refers to this analysis as the "tipping point."

Staff discusses at length the Company's analysis of a break-even point, or tipping point, with Portfolio 1-2 (Gas Peaker)—the next best alternative to Portfolio 1-4—to understand the sensitivity of the change in cost within the first ten-year planning period. This analysis demonstrates that Portfolio 1-4 is so robust that capital cost could vary by up to 40 percent and subscription rates could change by 15 percent before the portfolio hits the break-even point with the next best alternative.

In support of its subscription rate assumptions, Idaho Power states that there is significant demand for transmission capacity on its Idaho-Northwest transmission path. Idaho Power states that it is aware of over 4,000 MW of transmission requests on the existing transmission path, with only 133 MW of those requests being granted through 2007 due to limited transmission capacity. The Company claims that it is currently reviewing active transmission requests for the B2H Project. The Company states in its reply comments that it has entered into an agreement with PacifiCorp to negotiate the joint ownership and development of the B2H Project.

Even with a change in cost, Staff states that the Company's analysis also includes additional quantitative and qualitative risk measures that must be taken into consideration. According to Staff, Portfolio 1-4 scored higher than all the alternative portfolios in the Company's risk analyses. The different types of risk modeled in Idaho Power's 2009 IRP are renewable energy credit prices, natural gas prices, carbon emission costs, load growth, and lower conservation. Additionally, Idaho Power performed a qualitative risk analysis that looked at carbon regulation, technology, market risk, and resource siting. Therefore, the Boardman to Hemingway capital costs and subscription estimates would have to vary by more than 40 percent and 15 percent respectively to change the selection of the Portfolio 1-4 as the preferred portfolio for the 2010 through 2019 planning period.

In conclusion, Staff recommends that the Company continue to evaluate the B2H Project in its 2011 IRP. This on-going analysis of the B2H Project should include updated estimates of construction costs, documentation of progress the Company has made towards securing equity partners, and quantitative estimates of third-party subscription on the Boardman to Hemingway transmission line and future wheeling revenues. Staff additionally recommends that the Commission require that Idaho Power provide third-party documentation in support of the Company's construction cost estimates.

Staff's recommendation for further analysis of third-party subscription and the associated wheeling revenues is based on a concern that the active transmission requests referred to by Idaho Power in its 2009 IRP may not materialize, leaving Idaho Power customers liable for paying for an unused transmission line. Given these concerns, Staff initially recommended that the Commission's acknowledgement of the Boardman to Hemingway action item be conditioned on Idaho Power providing further analysis of these issues in its annual IRP update and next IRP.

In their final comments, ODOE and Idaho Power support Staff's recommendation for further information and analyses on the B2H Project in future IRP planning cycles. Idaho Power also agreed with Staff that if there are significant deviations from the IRP assumptions on issues such as construction costs, equity ownership, and subscription rates, then the Company must explain these deviations in its 2011 IRP. But given that Staff found the Company's estimates to be reasonable at this time, Idaho Power argues that conditional acknowledgment is not necessary. The Company agreed to provide additional analyses of the B2H Project, as prescribed in the eight conditions of Staff's proposed final order.

At the Commission public meeting on September 7, 2010, Staff revised its original recommendation for conditional acknowledgement and agreed with Idaho Power that, with the Company's commitment to continue to analyze and assess the B2H Project as an uncommitted resource, acknowledgement with requirements is a reasonable recommendation that meets the goals of Staff's proposed final order.

Finally, Staff discussed the future ratemaking treatment of the B2H Project. Staff reaffirmed that the Company will be required to compare its actual results with its IRP estimates. If the comparison shows significant deviations from its IRP assumptions, then the Company must provide an adequate explanation for why this project was the right resource as compared to an alternative.

In its opening comments, Renewable Northwest Project (RNP) urges the Commission to acknowledge Portfolio 1-3 (Gas Peaker and B2H) as the preferred portfolio for the first ten-year planning period. RNP states that it believes that the Company's commitment to 150 MW of wind energy and 40 MW of geothermal, coupled with the Boardman to Hemingway transmission line, will foster the growth of new renewable energy resources in the Northwest. Staff agrees with the latter half of RNP's statement, but points out that Idaho Power's preferred portfolio, Portfolio 1-4, also includes the Company's commitment to 150 MW of wind energy and 40 MW of geothermal. Therefore, Staff believes that Portfolio 1-4 meets RNP's goals.

In reply comments, RNP supported Staff's conclusions associated with Portfolio 1-3, and agreed with Staff that the Company's Portfolio 1-4 will also foster the growth of new renewable resources in the Northwest.

Commentators at the April 20, 2010 public comment hearing focused on the need for the B2H Project. Specifically, commentators believe that building a natural gas plant and additional purchased power are preferable to the Boardman to Hemingway transmission line, and that the line should not be built to accommodate third-party wheeling requests.

Idaho Power refutes each of these claims. First, Idaho Power notes the robustness of Portfolio 1-4 as compared to the other portfolios. Second, Idaho Power refutes the possibility of additional purchased power due to its limited transmission capacity during peaking time on existing transmission paths. Third, Idaho Power states that all wheeling requests on the proposed B2H Project will offset costs associated with building the project, which in turn will reduce its customers' rates. In addition, Idaho Power states that it is bound by federal law to provide wheeling services on a non-discriminatory basis, which requires the Company to construct a transmission system that will ensure reliable and economic service to transmission customers.

2. Resolution

As Staff notes, the dearth of recent transmission development 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. But our concern about this uncertainty is tempered by risk analyses showing that the "B2H portfolio" (Portfolio 1-4) is the best portfolio for customers over a range of capital costs and third-party subscription levels. Accordingly, we consider it reasonable to proceed with the B2H Project based on the information available now and acknowledge it as part of the Company's 2009 IRP.

We also adopt 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. We always expect utilities to update their assessments of previously acknowledged projects that are still in the planning or development stages at the time of an IRP acknowledgement. We make this updating requirement explicit for the B2H Project because of current uncertainty about underlying assumptions. We expect the Company to provide a thorough update of its B2H Project assumptions and its risk analysis in the 2011 IRP, with the understanding that the Commission's acknowledgment of the 2011 IRP will depend on the outcome of that updated analysis.

Finally, we reiterate that at the time of ratemaking any utility is required to show that its investment was a prudent decision. Given the inherent risk associated with a transmission facility and the possibility of escalating costs and delays in permitting, the Company will need to address any significant changes in construction cost, equity partnership, or expected third-party subscription and how these factors influenced the Company's decision to continue with the project.

C. Preferred Portfolio for the Second Ten-Year Planning Period and the Consolidated Preferred Portfolio

1. Parties' Positions

Idaho Power chose Portfolio 2-4 (Wind and Peakers) for the second ten-year planning period. Portfolio 2-4 consists of five single cycle combustion turbine (SCCT) gas resources with a combined capacity of 1,400 MW, two wind facilities with a combined capacity of 200 MW, and 100 MW of market purchases on PacifiCorp's proposed Gateway West transmission project. Idaho Power states that these resources represent a strategy of adding wind resources sufficient to provide energy and renewable energy credits (REC) along with simple-cycle natural gas plants to provide peaking capacity and operating reserves necessary to integrate wind generation.

In its final comments, Staff noted that the load forecast for the second ten-year planning period is relatively flat. The Company stated that the primary driver for new resources in the second period is the carbon emission reductions, due to coal curtailment, identified in the Waxman-Markey Bill. In its comments, RNP lauded Idaho Power for developing a resource portfolio that allows for considerable curtailment of the Company's coal-fired generation. RNP believes that Idaho Power's IRP strategy appropriately accounts for the costs, risks, and environmental concerns associated with future limits on greenhouse gas emissions.

Staff agrees with RNP and believes that Idaho Power complied with Guideline 8 of the Commission's IRP guidelines by modeling the carbon emission future that it believed was most likely to occur. But Staff cites the need for additional analysis, including the end-effects and costs of the retirement of a coal facility. Staff recommends that the Commission require that Idaho Power examine coal curtailment and the costs associated with coal plant retirement.

In its opening comments, RNP expressed concern that the portfolios rely too heavily on natural gas-fired resources. Staff agrees that Portfolio 2-4 relies too heavily on gas in the second ten-year planning period. Staff's primary concern, however, was not the concentration of gas in the second planning period, but the type of gas resource modeled. Because the primary reason for additional resources in the second ten-year planning period was due to modeled coal curtailment, Staff believes it is unreasonable for the Company to choose multiple SCCTs versus one or two CCCTs.

Staff and RNP believe that the Company needs to consider expanding the number of portfolios it considers in the second ten-year planning period. Staff notes that an IRP is designed to take into consideration a broad array of portfolio options. For the second ten-year planning period and the consolidated Preferred Portfolio, Staff discussed the design of Idaho Power's five alternative portfolios. Staff notes that the Company designed the five portfolios for the second ten-year planning period based on the selection of Portfolio 1-4 for the first ten-year planning period, which limits the resource options considered by Idaho Power.

Staff believes that building portfolios is a learning process examining multiple futures, and this learning process should not be overlooked. Staff believes that more than five portfolios should be developed for the second ten-year planning period. Staff therefore recommends that the Commission require Idaho Power to develop significantly more portfolios for the second ten-year planning period for its next IRP. In addition, Staff recommends that Idaho Power be required to provide a review of the benefits of a CCCT versus a SCCT, looking at variables such as cost effectiveness, operation and maintenance costs, and overall system benefit. In its final comments, Idaho Power supported Staff's recommendation.

In its final comments, ODOE also recognized the need for Idaho Power to develop more portfolios and suggested that the Company should consider uncertainty in its future analyses.

As part of the carbon cost evaluation, Staff recommends that Idaho Power be required to look at the likelihood of Environmental Protection Agency (EPA) regulations on air quality, fly ash, and water for all of its generation facilities. Staff believes the Company needs to include the operational impacts of these possible regulations for future consideration. In its final comments, Idaho Power supported Staff's recommendation.

2. Resolution

We support Idaho Power's selection of Portfolio 2-4 for the second ten-year planning period and the overall selection of the Preferred Portfolio. While we recognize the speculative nature of the second half of the planning period, we agree with Staff's conclusion that much can be learned from analyzing more portfolios and resource options. We therefore adopt Staff's recommendation and direct the Company to consider more portfolios, including those needed to evaluate the benefits of a CCCT versus a SCCT, in its next IRP cycle. We also direct the Company to include an analysis of potential EPA or other federal and state environmental policies that may affect Idaho Power's generation portfolio.

D. Demand-Side Management and Energy Efficiency Programs.

1. Parties' Positions

Several commentators at the April 20, 2010 public comment hearing argued that Idaho Power has been deficient in seeking energy savings. Commentators suggested that Idaho Power's energy efficiency efforts lag behind the regional goals established by the NPCC's Sixth Power Plan. They further asserted that the Company could supplant the need for the Boardman to Hemingway transmission line with increased DSM efforts.

Idaho Power responded to these remarks in its reply comments by explaining how they treat DSM in the planning process and by comparing the Company's efforts to the goals set by the NPCC. Idaho Power explains that prior to evaluating the need for traditional resources, the Company includes all cost-effective energy efficiency from existing and new programs in its load and resource balance. In other words, the Idaho Power gives first priority to obtaining cost-effective conservation. The Company then compares its efforts to the goals set by the NPCC. According to Idaho Power, in 2009 it exceeded the goals in NPCC's Fifth Power Plan by approximately 30 percent. Idaho Power also states that it is working aggressively to meet the goals set in the Sixth Power Plan.

In its final comments, Staff echoed the sentiments of Idaho Power and believes that the Company has explored and included all cost-effective DSM and energy efficiency programs in its 2009 IRP. In addition, Staff states that the Company has made great strides with its energy efficiency and DSM measures as compared to the Company's 2006 IRP.

2. Resolution

Idaho Power's existing and new energy efficiency programs are forecasted to reduce average annual system loads by 189 MWa by the year 2019 and 383 MWa by 2029. We agree with Staff that Idaho Power is running a reasonable set of programs to capture all cost-effective conservation. We also support the Company in its efforts to refine and improve upon its programs.

We find that Idaho Power cannot rely on additional cost-effective conservation in lieu of a supply-side resource to meet its summer capacity needs and maintain a reliable system. On a monthly basis, after counting energy efficiency savings, the Company forecasts a resource deficit of 155 MWa during July 2019. On a peak hour basis, after counting savings from existing and new energy efficiency programs and new demand response programs, the Company forecasts summertime capacity deficits as large as 471 MW during 2019. We concur with Staff and Idaho Power that a supply-side resource is required to meet these forecasted capacity deficits.

E. Policy Issues

1. Parties' Positions

In its opening comments, RNP did not agree with Idaho Power's recommendation to sell its RECs from its renewable energy projects until the Company is required to use the RECs to comply with a federal Renewable Energy Standard (RES). RNP believes Idaho Power should be retaining RECs in preparation for compliance with a future federal RES.

In its final comments, Staff notes that the Idaho Public Utilities Commission accepted Idaho Power's REC management plan filing on June 11, 2010.[12] This REC management plan is consistent with Idaho Power's IRP. In its reply comments, Idaho Power explained that its REC management strategy will benefit customers of Idaho Power in two ways. First, customers' rates will be reduced due to REC sales revenue. Second, the Company plans to continue to acquire and hold long-term contract rights to own RECs to meet future federal RES.

In addition, RNP supported the development of a solar pilot project in Idaho Power's service territory. RNP stated that it would like to participate in a stakeholder workshop with Idaho Power to explore options for a solar pilot project. In response to Staff final comments, RNP generally supported Staff's conclusions.

2. Resolution

We agree with Idaho Power's conclusion that its REC management strategy is in the best interest of customers, will reduce rates, and will provide the ability to meet future RES standards.

More recently, Idaho Power has participated in the pilot project for a solar feed-in tariff in Oregon. We believe Idaho Power's participation and introduction of the solar feed-in tariff fulfills RNP's request to develop a solar pilot project in Idaho Power's service territory.[13]

F. General Issues

1. Parties' Positions

In final comments, Staff noted several deficiencies in Idaho Power's narrative description of its 2009 IRP. Staff believes that Idaho Power should provide a more thorough explanation of the Company's selection of the Preferred Portfolio. Staff believes that Idaho Power failed to provide an adequate narrative of how the Preferred Portfolio performed in the risk analysis individually and comparatively to the other portfolios. Staff therefore recommended that the Commission require Idaho Power to devote specific chapters in its next IRP explaining the selection of its Preferred Portfolio in greater detail and as compared

[12] *See* Idaho Public Utilities Commission Case No. IPC-E-08-24, Order No. 32002.
[13] *See* Docket No. UM 1452.

to an alternative portfolio. Staff believes this narrative should include an explanation of the relative performance of each portfolio within each of the modeled risk measures, including charts and matrices showing the relative ranking of each portfolio using cost and risk metrics. Finally, Staff recommended that Idaho Power should be required to provide an explanation of how each portfolio performed with regard to the qualitative measures the Company considered in its selection process.

Staff also pointed out that Idaho Power's risk analysis consisted of modeling risk variables, such as load growth, in only one direction—high. In its Technical Appendix the Company did not model low load growth scenarios, low subscription rates, or low natural gas prices. Staff recommends the Company model the full range of possible futures for its risk variables, including both the high and low side, in the next IRP. In response to Staff's final comments, Idaho Power agrees with Staff's recommendations.

2. Resolution

We support Staff's recommendation regarding Idaho Power's next IRP cycle. As stated in Order No. 07-002, the Commission guidelines incorporate what we minimally expect from an IRP.[14] We always urge the utility to provide more, rather than less, information, especially given the increasing complexity of the planning process.

III. CONCLUSION

Idaho Power Company's 2009 Integrated Resource Plan, as highlighted in this order, reasonably adheres to the principles of resource planning established in Order No. 07-002 and is acknowledged with the following requirements:

1. Idaho Power Company will file its next integrated resource plan no later than June 30, 2011.

2. In its 2011 Integrated Resource Plan, Idaho Power Company will treat the Boardman to Hemingway transmission project as an uncommitted resource and will update its project analysis, including progress the Company has made towards securing equity partners, updated estimates of construction costs, and quantitative estimates of third-party subscription on the Boardman to Hemingway transmission line and future wheeling revenues. In addition, Idaho Power Company will provide third-party documentation in support of its construction cost estimates.

3. In its next planning cycle, Idaho Power Company will analyze coal curtailment and the costs associated with coal plant retirement.

[14] *See* Order 07-002 at 12.

4. In its next planning cycle, Idaho Power Company will develop significantly more portfolios for the second ten-year planning period, including portfolios designed to evaluate the benefits of a combined cycle combustion turbine gas resource versus multiple single cycle combustion turbine gas resources.

5. In its next planning cycle, Idaho Power Company, will analyze any potential Environmental Protection Agency, state, and other federal agency regulations associated with air quality, fly ash, and water that may affect the Company's generation facilities. These results will be included in the Company's 2011 Integrated Resource Plan.

6. In its 2011 Integrated Resource Plan, Idaho Power Company will provide a more robust justification for its load forecast for the second ten-year planning period. In addition, Idaho Power will provide additional analysis and a description of its estimated price response related to future carbon regulation for each customer class in its next IRP planning cycle.

7. In its 2011 Integrated Resource Plan, Idaho Power Company will devote specific chapters in the Plan to explaining the selection of the Preferred Portfolio in greater detail and as compared to an alternative portfolio. This narrative will include an explanation of the relative performance of each portfolio within each of the modeled risk measures, including charts and matrices showing the relative ranking of each portfolio using cost and risk metrics. Idaho Power Company will provide an explanation of how each portfolio performed using the qualitative measures the Company considered in its selection process.

8. In the 2011 Integrated Resource Plan, Idaho Power Company will model the full range of possible futures for its updated risk variables. Idaho Power Company will model both a high and low future for each variable.

At the Commission's September 7, 2010 public meeting, Idaho Power Company agreed to perform all of the above analyses in its 2011 Integrated Resource Plan and understood that the Commission's acknowledgement of Idaho Power's 2011 Integrated Resource Plan will be based upon the results of the updated analyses.[15]

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[15] For further details regarding Idaho Power's adherence to the Commission's Guidelines in Order No. 07-002, *see* Staff Final Comments, Appendix A: Adherence of the Plan to Integrated Resource Planning Guidelines (July 9, 2010).

IV. ORDER

IT IS ORDERED that:

1. The 2009 Integrated Resource Plan filed by Idaho Power Company on December 30, 2009, is acknowledged with the requirements set forth in this order.

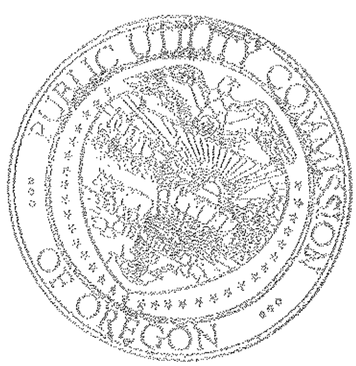
2. Idaho Power Company will file its next Integrated Resource Plan no later than June 30, 2011.

Made, entered, and effective OCT 11 2010.

Ray Baum
Chairman

John Savage
Commissioner

Susan K. Ackerman
Commissioner



ATTACHMENT N-4
ORDER NO. 12-177 IN DOCKET LC 53

ORDER NO. 12 177

ENTERED MAY 21 2012

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 53

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

DISPOSITION: INTEGRATED RESOURCE PLAN ACKNOWLEDGED WITH CONDITIONS AND EXCEPTIONS

I. INTRODUCTION

Idaho Power Company (Idaho Power) seeks acknowledgment of its 2011 Integrated Resource Plan (IRP). The Company submitted the IRP to meet the requirement that all regulated energy utilities operating in Oregon engage in integrated resource planning.[1] We acknowledge the company's 2011 IRP with conditions and exceptions.

II. BACKGROUND

We require each regulated energy utility to prepare and file an IRP within two years after acknowledgment of a utility's last IRP. Substantively, we require 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 an action plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.[2]

We acknowledge a utility's IRP to the extent the plan satisfies our procedural and substantive requirements, and the plan is deemed reasonable at the time of acknowledgement. Acknowledgment does not constitute a determination of the prudency of any resource acquisitions or other expenditures made by the utility pursuant to the plan. As a legal matter, we must reserve judgment on all rate-making issues.[3] Nonetheless, 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 IRP action plans. Utilities will also be

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[1] *See* Order Nos. 89-507, 07-002, and 07-047.
[2] *See* Order No. 07-002.
[3] *See* Order No. 07-002 at 24.

expected to explain actions they take which may be inconsistent with Commission-acknowledged plans.

III. PROCEDURAL HISTORY

Idaho Power filed its 2011 IRP on June 30, 2011. A prehearing conference was held July 29, 2011, and the schedule adopted. Petitions to intervene were granted on behalf of Renewable Northwest Project (RNP), Portland General Electric Company (PGE), the Oregon Department of Energy (ODOE), Move Idaho Power, and Stop Idaho Power. The Citizens' Utility Board of Oregon (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 on September 20, 2011. Staff and intervenor initial comments were filed October 18, 2011. Company reply comments were filed November 8, 2011. Staff's final comments and a proposed order were filed December 6, 2011. Company and intervenor comments in reply to Staff's final comments were filed January 3, 2012. Staff's report and its final proposed order were filed on January 24, 2012. This matter was taken up for Commission action at a public meeting on February 14, 2012.

IV. DISCUSSION

A. 2011 IRP Overview

Its 2011 IRP is Idaho Power's tenth resource plan filed to meet the requirements and guidelines established by this Commission and the Idaho Public Utilities Commission. In its filing Idaho Power assumed that, during the planning period (2011 through 2030), it will continue to be responsible for acquiring resources sufficient to serve all of its retail customers in its Oregon and Idaho service areas as a vertically integrated company. In developing its plan, Idaho Power worked with its IRP Advisory Council, which is comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, public utility commission representatives, and others. Following the filing of its final plan, Idaho Power presented the IRP at public meetings in various cities within its service area.

Idaho Power expects the number of customers in its service area to increase from about 492,000 in 2010 to over 650,000 by 2030. The IRP expected–case load forecast projects peak-hour load will grow 69 megawatts (MW) annually (1.8 percent), and average-system load will increase annually 29 average megawatts (aMW) (1.4 percent) over the 20-year term. In 2011, Idaho Power's demand response programs are expected to reduce peak-hour load by 330 MW. Two resources identified in the 2009 IRP are considered committed resources in the 2011 IRP: (1) the 300 MW Langley Gulch combined cycle combustion turbine that is expected to be available in the summer of 2012; and (2) a 49 MW upgrade of the Shoshone Falls Hydroelectric Project in 2015.

Idaho Power divided its 20-year planning period into two 10-year segments. In the first 10-year period, the company examined nine resource portfolios. Each portfolio was designed to substantially meet the energy and capacity deficits identified in the resource balance. For the second 10-year period, Idaho Power analyzed the preferred resource portfolio from the initial 10-year period coupled with each of the 10 portfolios considered for the second period.

In addition to those committed resources (Langley Gulch and the Shoshone Falls upgrade), the preferred resource portfolio includes 450 MW of market purchases beginning in 2016, with the completion of the Boardman to Hemingway transmission line. The total west-to-east transfer capacity reserved on Boardman to Hemingway by Idaho Power is expected to be 450 MW. For the second 10-year period the preferred portfolio adds a mixture of renewable resources along with natural gas-fired baseload and peaking resources.

B. Objections to Idaho Power's 2011 IRP

Staff and other parties raised numerous issues and provided considerable commentary on certain aspects and elements of the original action items in Idaho Power's IRP Action Plan. We also expressed concerns with aspects of the plan at the public meeting held on February 14, 2011. Those issues, and our resolution of them, are as follows:

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

Idaho Power does not wholly own or operate any coal plants, but does have a significant ownership interest in three large plants (Boardman, North Valmy, and Jim Bridger). As reported by CUB, these plants provide 41 percent of Idaho Power's total generation. CUB points out that the owners of these three plants likely will face increasing costs to comply with clean air regulations in the coming years.

CUB and RNP are not satisfied with Idaho Power's analysis of the possible environmental compliance costs associated with ownership and operation of these plants. CUB suggests 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 IRP provisions relating to coal plant investment are considered for acknowledgement. CUB recommends that the Commission withhold acknowledgment of the IRP until Idaho Power completes a study of its coal investment compliance costs and the parties have had the opportunity to review and comment on the study. RNP also recommends that the Commission require Idaho Power to analyze the costs and risks of maintaining its coal plants (including carbon costs and environmental regulations) before the company commits to significant investments.

Idaho Power responds that because the amount of any environmental compliance costs is "highly speculative" at this time, any analysis of the costs would be highly speculative as well. The company argues that the Commission should acknowledge its 2011 IRP, and require that Idaho Power conduct the environmental costs analysis in future IRP filings.

Staff shares CUB's and RNP's concerns about future environmental compliance costs, but agrees with Idaho Power that the company should provide the requested analysis in its 2011 IRP Update. Staff proposes an additional Action Item 11 to address this future requirement.

Resolution

As discussed at the public meeting, we share the concerns raised by CUB and RNP regarding Idaho Power's failure to perform a comprehensive study of the possible costs and consequences of environmental regulations associated with the company's partial ownership of three coal plants. Accordingly, we acknowledge Staff's proposed Action Item 11, but not any other IRP provision relating to new investments in coal plants until Idaho Power completes a study of its coal investment compliance costs and other parties have had the opportunity to comment on the study.

2. Boardman to Hemingway Transmission (Action Item 7)

RNP supports acknowledgment of the Boardman to Hemingway (B2H) transmission project as the primary resource in Idaho Power's near-term portfolio. Staff recommends we acknowledge Action Item 7 requiring Idaho Power to continue to make progress on the B2H transmission project between now and the completion of the company's 2013 IRP. CUB notes, however, that closure of one or more coal plants would open up capacity on existing transmission lines and could cause changes to the design and location of new lines.

Resolution

We share CUB's concern that coal cost study results will have implications for Idaho Power's transmission line use and plans, but acknowledge Action Item 7 requiring the company to continue to make progress on the B2H transmission project as an uncommitted resource.

3. Conservation Voltage Reduction (Action Item 4)

Staff notes the "promising beginnings" for conservation voltage reduction (CVR) measures reported by Idaho Power. Staff points out, however, that the Company shows no further CVR measures in either its IRP or its Appendix B on Demand-Side Management.

Resolution

We are convinced that there is an untapped CVR resource and that this resource is cost effective. 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 load-resource balance forecasts.

4. Demand Response (Action Item 3)

In this IRP cycle Idaho Power switched from an "all cost-effective DSM" approach to "need-based" approach. Based on its analysis comparing the costs of energy saved from demand response to the cost of owning and operating a simple cycle combustion turbine (SCCT), Idaho Power derived an optimal amount of demand response for its system. Staff believes that the Company should pursue all cost-effective demand response through existing programs and consider new programs as applicable. Staff believes Idaho Power should pursue the maximum amount of demand response that (1) is less costly on a kW basis than a supply-side resource, and (2) up to the company's system capacity deficit amount.

Resolution

Staff proposed no change to this IRP action item. We accept Staff's proposal that during the preparation of its 2013 IRP, Idaho Power will convene a meeting of its IRP Advisory Council to address demand response, where Staff intends to work with the parties to develop a demand response approach in the best interest of ratepayers.

5. Energy Efficiency (Action Items 1 and 2)

Staff recommends acknowledgment of Idaho Power's Action Items 1 and 2, and recommends the Company continue to pursue all cost-effective demand side management as the lowest cost resource for customers.

Resolution

We agree with Staff that Idaho Power should continue to pursue all cost-effective demand side management. No revision to these action items is required.

6. *Alternative Portfolio (Action Items 8 and 9)*

RNP urges the Commission to consider alternatives to acknowledging Idaho Power's alternative resource portfolio (which is comprised solely of SCCT plants). RNP recommends the Commission give demand side management and solar photovoltaic resources time to ripen. Staff recommends the Commission not acknowledge the alternative portfolio, because there are existing mechanisms in the IRP process to deal with unforeseen circumstances.

Resolution

We agree with Staff that there are existing mechanisms in the IRP process to address unforeseen circumstances and do not find a need to acknowledge an alternative resource portfolio. We clarify, however, that the non-acknowledgment of the Alternative Portfolio Action Items 8 and 9 is not due to a flaw or failure in the IRP.

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

In its Action Plan, Idaho Power included action items for the 2021 through 2030 time period. Because the IRP Guidelines focus on actions over the next two to four years, Staff recommends that these long-term action items not be acknowledged as part of this IRP.

Resolution

We agree with Staff that the desired focus in the IRP is on actions over the next two to four years. We decline to acknowledge the long-term action items contained in Action Item 12.

8. *Load Forecast*

Staff is concerned that Idaho Power's assumptions of average energy growth and peak-hour load growth are too high. Staff's concerns are based on the lingering economic conditions, plus shifts occurring in the demand/supply balance, conservation, and environmental regulation.

Resolution

We agree with Staff that the 2011 IRP Update and the 2013 IRP need to be based on an updated load forecast that reflects current conditions. We concur that it is appropriate to include an allowance for new large loads in the load forecast only if there is a signed energy service agreement, and the load forecast is based on specific supporting documentation.

9 *Risk Analysis*

Staff is troubled by aspects of Idaho Power's stochastic risk analyses, as contrasted with the more conventional approaches used by other Oregon utilities. With the approach used by Idaho Power, 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 also recommends the company include hydro generation variability as a risk factor for its next IRP cycle, in light of Idaho Power's significant reliance on hydroelectric generation.

Resolution

We adopt Staff's recommendation that the 2013 IRP risk analysis should include hydroelectric generation variability. We agree with Staff's goal of working toward collaborative improvement of Idaho Power's stochastic risk analysis. At least one of the 2013 IRP meetings of the IRP Advisory Committee should focus on this subject.

10. *Wind Integration Study*

RNP noted that Idaho Power is conducting a wind integration study internally. It encouraged the company to look for ways to lower its costs of wind integration, to seek independent technical review of its study, and to provide stakeholders the chance to provide meaningful feedback.

Resolution

We agree that Idaho Power should seek independent technical review of its wind integration study and allow stakeholders the opportunity to provide feedback before the study results are incorporated into the company's next IRP. Accordingly, we direct Idaho Power to form a wind integration study technical review committee that is fully engaged in the process. We also direct Idaho Power to establish a schedule for workshops, providing full opportunity for stakeholder involvement.

11. *Solar Photovoltaic Analysis*

RNP encourages Idaho Power to evaluate the performance of solar photovoltaic projects as a class, not simply as single projects. The geographic distribution of the projects could have a significant effect of smoothing the short-term variability of single projects.

Resolution

We agree with RNP that Idaho Power should evaluate the performance of the solar photovoltaic projects as a class, as consistent with the goals of the pilot program.

12. Adherence of Plan to Integrated Resource Planning Guidelines

Intervenors and Staff agree that Idaho Power's 2011 IRP filing did not comply with IRP Guidelines 1(c) and 4(g),[4] because the company failed to provide a comprehensive evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations. Without that evaluation, it was not possible to determine whether any of the candidate resource portfolios met the specified standard.

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

Staff also noted that Idaho Power did not comply with IRP Guidelines 4(a) and 4(n), because the company did not explain how the utility met each substantive and procedural requirement, nor provide a concise listing of action items for all resources and resource related activities.

Resolution

We note Idaho Power's high-level presentation about environmental compliance costs, and expect more detailed information to be provided in the company's coal study. We agree with Staff that future Idaho Power IRPs should include: (1) an explanation of how the utility met each substantive and procedural requirement, and (2) a concise listing of action items for all resources and resource related activities, with each action item numbered.

[4] IRP Guideline 1(c) prescribes 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 its customers. IRP Guideline 4(g) requires the utility to identify key assumptions about the future, including future enviromnental compliance costs.

IV. ORDER

IT IS ORDERED that the 2011 Integrated Resource Plan filed by Idaho Power Company is acknowledged with conditions and exceptions contained in this order, with the action items and recommendations summarized in Appendix A .

This order memorializes the decision of the Public Utility Commission of Oregon made and effective at a public meeting held on February 14, 2012.

Dated this 21 day of May, 2012, at Salem, Oregon.

John Savage
Commissioner

Susan K. Ackerman
Commissioner

Stephen M. Bloom
Commissioner

Appendix A
Adopted Action Items and Recommendations for Future IRPs

Idaho Power 2011 Integrated Resource Plan (IRP)

Action Items:

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 item in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource 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 – 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 – as described for preferred portfolio Action Item 5.~~

~~Action Item 9 - Simple Cycle Combustion Turbine – 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 – as outlined in IRP Table 10.2~~

Recommendations for future Idaho Power IRPs:

1. During preparation of the 2013 IRP, there be an Integrated Resource Plan Advisory Council (IRPAC) meeting specifically focused on demand response. Staff will participate in that meeting, and work with the Company and parties to develop a demand response approach that is in the best interest of ratepayers.

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

3. Related to the new large load issue, include an allowance for new large loads in the load forecast only if there is a signed energy service agreement. Further, include an allowance for new large loads in the load and resource balance, but the new large load must be based on specific supporting documentation.

4. Toward the goal of working collaboratively to improve of the stochastic risk analysis, at least one 2013 IRP IRPAC meeting should be set aside to focus on this subject. Further, the 2013 IRP risk analysis should include hydroelectric generation variability. In the risk analysis focused IRPAC meeting, the Company should vet its approach to including hydroelectric generation variability in the 2013 IRP risk analysis.

5. Form a wind integration study technical review committee as soon as possible. The committee is recommended to be fully engaged to review and offer suggestions for improvement of the Company's proposals for analytical methods and data used in the study. In addition, establish as soon as possible, a schedule for workshops providing full opportunity for stakeholder involvement and progress reviews. Finally, in 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.

6. Include in future IRPs an explanation of how the utility met each substantive and procedural requirement, as required by Guideline 4(a).

7. Include in future IRPs an action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, as required by IRP Guideline 4(n).

8. Include in future IRPs a concise listing of action items for all resources and resource related activities, with each action item numbered.

ATTACHMENT N-5
NAMEPLATE CAPACITY FACTORS

Exhibit N 3.3.6 Table
Idaho Power - Power Supply
T Noll May 2012

Annual Capacity Factors

	2011	2012	2013	2014	2015	2016	2017
Hydro Nameplate Capacity (MW)[1]	1,709	1,709	1,709	1,709	1,709	1,709	1,758
Annual Hydro Forecast (aMW) at 50th Percentile Water	982.3	982.1	981.3	977.4	974.9	972.0	987.2
Hydro Annual Capacity factor at 90th Percentile Water	**0.57**	**0.57**	**0.57**	**0.57**	**0.57**	**0.57**	**0.56**
Annual Hydro Forecast (aMW) at 70th Percentile Water	807.8	806.7	805.8	800.2	795.4	792.3	793.9
Hydro Annual Capacity factor at 70th Percentile Water	**0.47**	**0.47**	**0.47**	**0.47**	**0.47**	**0.46**	**0.45**
Annual Hydro Forecast (aMW) at 90th Percentile Water	681.9	681.2	680.4	676.9	673.3	665.0	661.9
Hydro Annual Capacity factor at 90th Percentile Water	**0.40**	**0.40**	**0.40**	**0.40**	**0.39**	**0.39**	**0.38**
Total Coal Annual Forecast (aMW)	879.3	891.6	867.0	879.5	870.3	900.6	908.0
Total Coal Nameplate Capacity (MW) (2) (3)	1,118.2	1,118.2	1,118.2	1,118.2	1,118.2	1,118.2	1,118.2
Coal Annual Capacity Factor	**0.79**	**0.80**	**0.78**	**0.79**	**0.78**	**0.81**	**0.81**
Total CCCT Annual Forecast (aMW)	0.0	125.5	251.0	251.0	251.0	251.0	251.0
Total CCCT Nameplate Capacity (MW) (4),(5)	0.0	150.0	300.0	300.0	300.0	300.0	300.0
CCCT Annual Capacity Factor	**0.00**	**0.84**	**0.84**	**0.84**	**0.84**	**0.84**	**0.84**
Total SCCT Annual Forecast (aMW)	96.8	96.1	96.8	96.8	97.6	96.8	96.1
Total SCCT Nameplate Capacity (MW) (6)	443.7	443.7	443.7	443.7	443.7	443.7	443.7
SCCT Annual Capacity Factor	**0.22**	**0.22**	**0.22**	**0.22**	**0.22**	**0.22**	**0.22**

(1) Shoshone Falls upgrade assumed to be operational in 2017
(2) Boardman coal plant assumed to be decommissioned after 2020
(3) Coal nameplate capacity assumes Idaho Power share

[4] Langley Gulch nameplate capacity assumed to be 300 MW

[5] Additional 300 MW CCCT assumed to be operational in 2025

[6] Two additional 170 MW SCCT units assumed to be operational, one in 2022 and the second in 2029

Construction Notes (not for publication)

Existing Nameplate Capacity from 2011 IRP page 27

Hydro forecast values from 2011 IRP Technical Appendix, pages 96 through 125

Coal, CCCT, SCCT forrecast values from 2011 IRP Technical Appendix

2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
1,758	1,758	1,758	1,758	1,758	1,758	1,758	1,758	1,758	1,758	1,758	1,758	1,758
982.6	979.0	976.6	975.1	973.9	973.5	973.5	973.5	973.5	973.5	973.5	973.5	973.5
0.56	**0.56**	**0.56**	**0.55**	**0.55**	**0.55**	**0.55**	**0.55**	**0.55**	**0.55**	**0.55**	**0.55**	**0.55**
788.8	784.8	781.5	778.9	777.6	777.1	777.1	777.1	777.1	777.1	777.1	777.1	777.1
0.45	**0.45**	**0.44**	**0.44**	**0.44**	**0.44**	**0.44**	**0.44**	**0.44**	**0.44**	**0.44**	**0.44**	**0.44**
657.9	655.1	653.2	651.8	650.3	650.0	650.0	650.0	650.0	650.0	650.0	650.0	650.0
0.37	**0.37**	**0.37**	**0.37**	**0.37**	**0.37**	**0.37**	**0.37**	**0.37**	**0.37**	**0.37**	**0.37**	**0.37**
913.7	917.0	918.6	867.1	863.0	866.4	867.8	867.1	863.0	866.4	867.8	867.1	863.0
1,118.2	1,118.2	1,118.2	1,118.2	1,059.6	1,059.6	1,059.6	1,059.6	1,059.6	1,059.6	1,059.6	1,059.6	1,059.6
0.82	**0.82**	**0.82**	**0.78**	**0.81**	**0.82**	**0.82**	**0.82**	**0.81**	**0.82**	**0.82**	**0.82**	**0.81**
251.0	251.0	251.0	251.0	251.0	251.0	251.0	397.4	502.0	502.0	502.0	502.0	502.0
300.0	300.0	300.0	300.0	300.0	300.0	300.0	600.0	600.0	600.0	600.0	600.0	600.0
0.84	**0.84**	**0.84**	**0.84**	**0.84**	**0.84**	**0.84**	**0.66**	**0.84**	**0.84**	**0.84**	**0.84**	**0.84**
96.8	96.8	97.6	97.6	121.6	120.9	120.8	120.8	121.6	121.6	120.1	144.9	144.9
443.7	443.7	443.7	443.7	613.7	613.7	613.7	613.7	613.7	613.7	613.7	783.7	783.7
0.22	**0.22**	**0.22**	**0.22**	**0.20**	**0.20**	**0.20**	**0.20**	**0.20**	**0.20**	**0.20**	**0.18**	**0.18**

Data from 2011 06 01 Load and resource Balance for Appendix C.xlsx

Year	Month	Date	Coal	Langley	NewCCCT	CCCT	Peakers	NewSCCT1	NewSCCT2	SCCT
2011	1	1/1/2011	933.4	0.0	0.0	0.0	223.7	0.0	0.0	223.7
2011	2	2/1/2011	933.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	3	3/1/2011	863.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	4	4/1/2011	669.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	5	5/1/2011	646.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	6	6/1/2011	913.7	0.0	0.0	0.0	240.4	0.0	0.0	240.4
2011	7	7/1/2011	932.4	0.0	0.0	0.0	223.7	0.0	0.0	223.7
2011	8	8/1/2011	932.4	0.0	0.0	0.0	241.5	0.0	0.0	241.5
2011	9	9/1/2011	932.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	10	10/1/2011	931.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	11	11/1/2011	932.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	12	12/1/2011	932.4	0.0	0.0	0.0	232.6	0.0	0.0	232.6
2012	1	1/1/2012	932.4	0.0	0.0	0.0	223.7	0.0	0.0	223.7
2012	2	2/1/2012	932.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	3	3/1/2012	885.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	4	4/1/2012	775.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	5	5/1/2012	734.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	6	6/1/2012	851.4	0.0	0.0	0.0	240.4	0.0	0.0	240.4
2012	7	7/1/2012	931.4	251.0	0.0	251.0	223.7	0.0	0.0	223.7
2012	8	8/1/2012	931.4	251.0	0.0	251.0	241.5	0.0	0.0	241.5
2012	9	9/1/2012	931.4	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2012	10	10/1/2012	930.2	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2012	11	11/1/2012	931.4	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2012	12	12/1/2012	931.4	251.0	0.0	251.0	223.7	0.0	0.0	223.7
2013	1	1/1/2013	931.4	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2013	2	2/1/2013	931.4	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2013	3	3/1/2013	852.2	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2013	4	4/1/2013	558.5	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2013	5	5/1/2013	612.4	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2013	6	6/1/2013	931.4	251.0	0.0	251.0	231.1	0.0	0.0	231.1

2013	7	7/1/2013	931.4	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2013	8	8/1/2013	931.4	251.0	0.0	251.0	241.5	0.0	0.0	241.5
2013	9	9/1/2013	931.4	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2013	10	10/1/2013	930.2	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2013	11	11/1/2013	931.4	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2013	12	12/1/2013	931.4	251.0	0.0	251.0	223.7	0.0	0.0	223.7
2014	1	1/1/2014	931.4	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2014	2	2/1/2014	931.4	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2014	3	3/1/2014	879.6	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2014	4	4/1/2014	584.1	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2014	5	5/1/2014	721.9	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2014	6	6/1/2014	920.5	251.0	0.0	251.0	231.1	0.0	0.0	231.1
2014	7	7/1/2014	931.0	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2014	8	8/1/2014	931.0	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2014	9	9/1/2014	931.0	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2014	10	10/1/2014	929.8	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2014	11	11/1/2014	931.0	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2014	12	12/1/2014	931.0	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2015	1	1/1/2015	931.0	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2015	2	2/1/2015	931.0	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2015	3	3/1/2015	834.0	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2015	4	4/1/2015	634.1	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2015	5	5/1/2015	714.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2015	6	6/1/2015	814.4	251.0	0.0	251.0	240.4	0.0	0.0	240.4
2015	7	7/1/2015	931.0	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2015	8	8/1/2015	931.0	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2015	9	9/1/2015	931.0	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2015	10	10/1/2015	929.8	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2015	11	11/1/2015	931.0	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2015	12	12/1/2015	931.0	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2016	1	1/1/2016	931.0	251.0	0.0	251.0	223.7	0.0	0.0	223.7
2016	2	2/1/2016	931.0	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2016	3	3/1/2016	898.4	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2016	4	4/1/2016	823.4	251.0	0.0	251.0	0.0	0.0	0.0	0.0

2016	5	5/1/2016	715.2	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2016	6	6/1/2016	887.8	251.0	0.0	251.0	240.4	0.0	0.0	240.4
2016	7	7/1/2016	937.0	251.0	0.0	251.0	223.7	0.0	0.0	223.7
2016	8	8/1/2016	937.0	251.0	0.0	251.0	241.5	0.0	0.0	241.5
2016	9	9/1/2016	937.0	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2016	10	10/1/2016	935.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2016	11	11/1/2016	937.0	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2016	12	12/1/2016	937.0	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2017	1	1/1/2017	937.0	251.0	0.0	251.0	223.7	0.0	0.0	223.7
2017	2	2/1/2017	937.0	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2017	3	3/1/2017	904.4	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2017	4	4/1/2017	840.0	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2017	5	5/1/2017	704.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2017	6	6/1/2017	915.6	251.0	0.0	251.0	240.4	0.0	0.0	240.4
2017	7	7/1/2017	943.0	251.0	0.0	251.0	223.7	0.0	0.0	223.7
2017	8	8/1/2017	943.0	251.0	0.0	251.0	241.5	0.0	0.0	241.5
2017	9	9/1/2017	943.0	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2017	10	10/1/2017	941.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2017	11	11/1/2017	943.0	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2017	12	12/1/2017	943.0	251.0	0.0	251.0	223.7	0.0	0.0	223.7
2018	1	1/1/2018	943.0	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2018	2	2/1/2018	947.0	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2018	3	3/1/2018	943.0	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2018	4	4/1/2018	841.4	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2018	5	5/1/2018	726.3	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2018	6	6/1/2018	899.6	251.0	0.0	251.0	240.4	0.0	0.0	240.4
2018	7	7/1/2018	944.2	251.0	0.0	251.0	223.7	0.0	0.0	223.7
2018	8	8/1/2018	944.2	251.0	0.0	251.0	241.5	0.0	0.0	241.5
2018	9	9/1/2018	944.2	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2018	10	10/1/2018	942.9	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2018	11	11/1/2018	944.2	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2018	12	12/1/2018	944.2	251.0	0.0	251.0	223.7	0.0	0.0	223.7
2019	1	1/1/2019	944.2	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2019	2	2/1/2019	944.2	251.0	0.0	251.0	0.0	0.0	0.0	0.0

2019	3	3/1/2019	944.2	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2019	4	4/1/2019	842.6	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2019	5	5/1/2019	727.5	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2019	6	6/1/2019	900.8	251.0	0.0	251.0	231.1	0.0	0.0	231.1
2019	7	7/1/2019	950.2	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2019	8	8/1/2019	950.2	251.0	0.0	251.0	241.5	0.0	0.0	241.5
2019	9	9/1/2019	950.2	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2019	10	10/1/2019	948.9	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2019	11	11/1/2019	950.2	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2019	12	12/1/2019	950.2	251.0	0.0	251.0	223.7	0.0	0.0	223.7
2020	1	1/1/2020	944.2	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2020	2	2/1/2020	946.2	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2020	3	3/1/2020	944.2	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2020	4	4/1/2020	838.1	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2020	5	5/1/2020	729.5	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2020	6	6/1/2020	896.2	251.0	0.0	251.0	240.4	0.0	0.0	240.4
2020	7	7/1/2020	954.2	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2020	8	8/1/2020	955.2	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2020	9	9/1/2020	948.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2020	10	10/1/2020	956.2	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2020	11	11/1/2020	950.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2020	12	12/1/2020	959.2	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2021	1	1/1/2021	888.7	251.0	0.0	251.0	223.7	0.0	0.0	223.7
2021	2	2/1/2021	880.6	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2021	3	3/1/2021	888.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2021	4	4/1/2021	788.1	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2021	5	5/1/2021	727.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2021	6	6/1/2021	840.7	251.0	0.0	251.0	240.4	0.0	0.0	240.4
2021	7	7/1/2021	898.7	251.0	0.0	251.0	241.5	0.0	0.0	241.5
2021	8	8/1/2021	899.7	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2021	9	9/1/2021	893.1	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2021	10	10/1/2021	900.8	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2021	11	11/1/2021	895.1	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2021	12	12/1/2021	903.7	251.0	0.0	251.0	232.6	0.0	0.0	232.6

2022	1	1/1/2022	887.2	251.0	0.0	251.0	223.7	0.0	0.0	223.7
2022	2	2/1/2022	891.2	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2022	3	3/1/2022	887.2	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2022	4	4/1/2022	791.1	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2022	5	5/1/2022	724.2	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2022	6	6/1/2022	843.7	251.0	0.0	251.0	240.4	98.1	0.0	338.4
2022	7	7/1/2022	888.7	251.0	0.0	251.0	223.7	91.5	0.0	315.2
2022	8	8/1/2022	888.7	251.0	0.0	251.0	241.5	98.9	0.0	340.4
2022	9	9/1/2022	888.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2022	10	10/1/2022	887.5	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2022	11	11/1/2022	888.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2022	12	12/1/2022	888.7	251.0	0.0	251.0	241.5	0.0	0.0	241.5
2023	1	1/1/2023	888.7	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2023	2	2/1/2023	888.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2023	3	3/1/2023	888.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2023	4	4/1/2023	792.6	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2023	5	5/1/2023	725.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2023	6	6/1/2023	845.2	251.0	0.0	251.0	240.4	98.1	0.0	338.4
2023	7	7/1/2023	894.7	251.0	0.0	251.0	223.7	91.5	0.0	315.2
2023	8	8/1/2023	894.7	251.0	0.0	251.0	241.5	98.9	0.0	340.4
2023	9	9/1/2023	894.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2023	10	10/1/2023	893.5	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2023	11	11/1/2023	894.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2023	12	12/1/2023	894.7	251.0	0.0	251.0	223.7	0.0	0.0	223.7
2024	1	1/1/2024	888.7	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2024	2	2/1/2024	888.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2024	3	3/1/2024	888.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2024	4	4/1/2024	788.1	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2024	5	5/1/2024	727.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2024	6	6/1/2024	840.7	251.0	0.0	251.0	231.1	98.1	0.0	329.2
2024	7	7/1/2024	898.7	251.0	0.0	251.0	232.6	91.5	0.0	324.1
2024	8	8/1/2024	899.7	251.0	0.0	251.0	241.5	98.9	0.0	340.4
2024	9	9/1/2024	893.1	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2024	10	10/1/2024	900.8	251.0	0.0	251.0	0.0	0.0	0.0	0.0

2024	11	11/1/2024	895.1	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2024	12	12/1/2024	903.7	251.0	0.0	251.0	223.7	0.0	0.0	223.7
2025	1	1/1/2025	888.7	251.0	0.0	251.0	232.6	0.0	0.0	232.6
2025	2	2/1/2025	880.6	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2025	3	3/1/2025	888.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2025	4	4/1/2025	788.1	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2025	5	5/1/2025	727.7	251.0	0.0	251.0	0.0	0.0	0.0	0.0
2025	6	6/1/2025	840.7	251.0	251.0	502.0	231.1	98.1	0.0	329.2
2025	7	7/1/2025	898.7	251.0	251.0	502.0	232.6	91.5	0.0	324.1
2025	8	8/1/2025	899.7	251.0	251.0	502.0	232.6	98.9	0.0	331.5
2025	9	9/1/2025	893.1	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2025	10	10/1/2025	900.8	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2025	11	11/1/2025	895.1	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2025	12	12/1/2025	903.7	251.0	251.0	502.0	232.6	0.0	0.0	232.6
2026	1	1/1/2026	887.2	251.0	251.0	502.0	232.6	0.0	0.0	232.6
2026	2	2/1/2026	891.2	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2026	3	3/1/2026	887.2	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2026	4	4/1/2026	791.1	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2026	5	5/1/2026	724.2	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2026	6	6/1/2026	843.7	251.0	251.0	502.0	240.4	98.1	0.0	338.4
2026	7	7/1/2026	888.7	251.0	251.0	502.0	232.6	91.5	0.0	324.1
2026	8	8/1/2026	888.7	251.0	251.0	502.0	232.6	98.9	0.0	331.5
2026	9	9/1/2026	888.7	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2026	10	10/1/2026	887.5	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2026	11	11/1/2026	888.7	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2026	12	12/1/2026	888.7	251.0	251.0	502.0	232.6	0.0	0.0	232.6
2027	1	1/1/2027	888.7	251.0	251.0	502.0	223.7	0.0	0.0	223.7
2027	2	2/1/2027	888.7	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2027	3	3/1/2027	888.7	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2027	4	4/1/2027	792.6	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2027	5	5/1/2027	725.7	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2027	6	6/1/2027	845.2	251.0	251.0	502.0	240.4	98.1	0.0	338.4
2027	7	7/1/2027	894.7	251.0	251.0	502.0	241.5	91.5	0.0	333.1
2027	8	8/1/2027	894.7	251.0	251.0	502.0	232.6	98.9	0.0	331.5

2027	9	9/1/2027	894.7	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2027	10	10/1/2027	893.5	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2027	11	11/1/2027	894.7	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2027	12	12/1/2027	894.7	251.0	251.0	502.0	232.6	0.0	0.0	232.6
2028	1	1/1/2028	888.7	251.0	251.0	502.0	223.7	0.0	0.0	223.7
2028	2	2/1/2028	888.7	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2028	3	3/1/2028	888.7	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2028	4	4/1/2028	788.1	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2028	5	5/1/2028	727.7	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2028	6	6/1/2028	840.7	251.0	251.0	502.0	240.4	98.1	0.0	338.4
2028	7	7/1/2028	898.7	251.0	251.0	502.0	223.7	91.5	0.0	315.2
2028	8	8/1/2028	899.7	251.0	251.0	502.0	241.5	98.9	0.0	340.4
2028	9	9/1/2028	893.1	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2028	10	10/1/2028	900.8	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2028	11	11/1/2028	895.1	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2028	12	12/1/2028	903.7	251.0	251.0	502.0	223.7	0.0	0.0	223.7
2029	1	1/1/2029	888.7	251.0	251.0	502.0	232.6	0.0	0.0	232.6
2029	2	2/1/2029	880.6	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2029	3	3/1/2029	888.7	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2029	4	4/1/2029	788.1	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2029	5	5/1/2029	727.7	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2029	6	6/1/2029	840.7	251.0	251.0	502.0	240.4	98.1	98.1	436.5
2029	7	7/1/2029	898.7	251.0	251.0	502.0	223.7	91.5	91.5	406.7
2029	8	8/1/2029	899.7	251.0	251.0	502.0	241.5	98.9	98.9	439.3
2029	9	9/1/2029	893.1	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2029	10	10/1/2029	900.8	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2029	11	11/1/2029	895.1	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2029	12	12/1/2029	903.7	251.0	251.0	502.0	223.7	0.0	0.0	223.7
2030	1	1/1/2030	887.2	251.0	251.0	502.0	232.6	0.0	0.0	232.6
2030	2	2/1/2030	891.2	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2030	3	3/1/2030	887.2	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2030	4	4/1/2030	791.1	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2030	5	5/1/2030	724.2	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2030	6	6/1/2030	843.7	251.0	251.0	502.0	240.4	98.1	98.1	436.5

2030	7	7/1/2030	888.7	251.0	251.0	502.0	223.7	91.5	91.5	406.7
2030	8	8/1/2030	888.7	251.0	251.0	502.0	241.5	98.9	98.9	439.3
2030	9	9/1/2030	888.7	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2030	10	10/1/2030	887.5	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2030	11	11/1/2030	888.7	251.0	251.0	502.0	0.0	0.0	0.0	0.0
2030	12	12/1/2030	888.7	251.0	251.0	502.0	223.7	0.0	0.0	223.7

Data from 2011IRPAvgGen.accdb
AnnualGenDataQ

Year	Coal MWa	CCCT MWa	SCCT MWa
2011	879.3	0	96.8
2012	891.6	125.5	96.1
2013	867	251	96.8
2014	879.5	251	96.8
2015	870.3	251	97.6
2016	900.6	251	96.8
2017	908	251	96.1
2018	913.7	251	96.8
2019	917	251	96.8
2020	918.6	251	97.6
2021	867.1	251	97.6
2022	863	251	121.6
2023	866.4	251	120.9
2024	867.8	251	120.8
2025	867.1	397.4	120.8
2026	863	502	121.6
2027	866.4	502	121.6
2028	867.8	502	120.1
2029	867.1	502	144.9
2030	863	502	144.9