

2009 IRP Advisory Council Meeting Minutes

Date: Wednesday, December 17, 2008

Location: Idaho Power CHQ Auditorium

Introductions/Meeting Overview - Mark Stokes

Mark Stokes welcomed the participants to the meeting. He introduced two new IRPAC participants; TJ Golo who was sitting in for Rick Sterling from the Idaho Public Utilities Commission and John Velikoff from Micron. Mr. Stokes then reviewed the agenda for the day and stated that the afternoon's focus would be on the development of Idaho Power's initial resource portfolios for the 2009 Integrated Resource Plan.

David Hawk asked whether Idaho Power had received new gas and oil prices from PIRA. Mr. Stokes replied that he did not have that information but would check to see if an updated forecast was available from PIRA.

Mr. Stokes then introduced Cory Read from Idaho Power's Energy Efficiency and Customer Relations Department.

Demand-Side Management – Cory Read

Cory Read began his presentation by explaining the process flow for committing new DSM as a resource for IRP portfolio selection. Mr. Read presented an overview of assumptions pertaining to DSM cost-effectiveness including the continued use of a 170 MW simple cycle combustion turbine and seasonal market price forecasts as the alternative generating resource for DSM activities. Mr. Read explained the difference between committed DSM resources in a previous sales and load forecast presentation and the numbers in this presentation that represent new DSM resource commitments.

David Hawk stated that DSM efforts are funded by customers and approved by Idaho Power through a cost-effectiveness process. He asked whether Idaho Power spends all of the energy efficiency rider money. Pete Pengilly responded that Idaho Power does not recover all of the costs of the energy efficiency programs. Ken Miller asked if Idaho Power is planning to increase the energy efficiency rider, and it was clarified that the energy efficiency rider is not part of the current rate case. David Hawk mentioned that industrial customers are not opposed to the collection of energy efficiency rider dollars as long as they can earn them back through incentives. Pete Pengilly clarified the energy efficiency policy, stating that Idaho Power strives for balance between incentives and revenues to the account and the program does not carry a large balance.

David Hawk asked for clarification regarding the Energy Efficiency Advisory Group and asked whether this group would review proposals which would allow Idaho Power to recover all DSM costs. He mentioned that Simplot is a proponent for Idaho Power recovering all of its costs for DSM related expenses. An additional question was raised on whether Idaho Power engaged in any outsourced DSM programs. Idaho Power clarified that some programs, such as AC Cool Credits, have their administration outsourced, but are subject to the same cost-effectiveness hurdle that internal programs face.

Mr. Read reviewed the hourly pricing period methodology and the explained the difference between summer and non-summer pricing and peak, mid-peak, and off-peak hours during those two seasons. He then presented the first ten years of the seasonal market price forecast used to value DSM savings not occurring during peak afternoon summer hours. Mr. Read explained that the large price increase occurring between 2011 and 2012 was due to the \$43/ton carbon tax that was included in the resource assumptions to hedge against possible future legislation.

John Velikoff asked for additional clarification regarding the pricing. It was explained that pricing is dependent on the current working portfolio and its interaction with WECC resources. Ken Miller asked why the carbon adder was included in 2012 instead of 2010. Rick Haener responded that the intent was to mirror what was expected with regards to passed legislation and implementation. Kevin Kitz made a recommendation that plant maintenance be considered in the avoided costs calculations.

Mr. Read presented the avoided capacity costs to be included in the 2009 IRP, demonstrating the difference in the costs estimated for the 2006 IRP and the current 2009 assumptions of building a peaking gas plant. Due to lower operating costs and decreased transmission upgrades, the 30-year levelized costs are estimated to be \$63.00 compared with \$64.92 in 2006. Mr. Hawk questioned the 31% reduction in operating costs. Randy Henderson replied that 2006 cost numbers were based on published industry amounts, whereas the 2009 estimate was based on actual operation data from Idaho Power's existing plants. Kevin Kitz asked if the capacity estimate was used for the peak summer hours only and if the other hours capture capacity value. Mr. Read clarified that the alternative resource is the market during non-peak hours when there is available transmission.

Mr. Read completed his presentation by showing charts that depict the magnitude of new DSM being presented for the 2009 IRP. Residential will have the most impact because of the programs already being planned in addition to estimated potential new DSM. It was explained that new DSM resources that reduce peak summer system loads will increase dramatically and will reach nearly 240 MW in five years with the expansion of the Irrigation Peak Rewards program. Lynn Tominaga stated the new program will meet these goals because of the program's cooperative redesign by the Irrigation Pumper Association of Idaho and Idaho Power. It was also clarified for Ken Miller that the new program would be dispatchable. Mr. Read pointed out that 54 MW was reduced in 2008 from existing programs. It was noted that the existing program for irrigators that relies on timer controls would be still available. Kevin Kitz recommended that the chart be amended for comparison purposes to show current program results.

IPC Solar Rooftop Array Data – Rich Pagoaga

Rich Pagoaga presented a graph showing the output of Idaho Power's 25 kW CHQ Rooftop Solar Photovoltaic (PV) Array. This was a follow-up to the September 16, 2008 presentation to the IRPAC on the Black & Veatch Solar Feasibility Study in which David Hawk expressed interest in viewing the solar generation output from Idaho Power's solar rooftop PV array. Mr. Pagoaga explained that metering on the solar array has always existed, but was not easily accessible. New metering has now been installed and can be easily accessed from the company's data repository system.

Mr. Pagoaga explained that the data presented was from December 1 thru December 14, 2008. He noted that the data points were from the National Weather Service's "Percent of Possible Sunshine" metric which he explained is essentially a measure of the cloudiness of a day. Mr. Pagoaga pointed out the generation curve's parabolic shape with a peak at noon, and referenced the low generation that occurred on two snowy and cloudy days. Mr. Pagoaga explained that December is the lowest solar PV generation month. He offered to make additional solar generation data available to the IRPAC at an upcoming spring meeting.

Supply-Side Resource Stack – Randy Henderson

Mr. Henderson presented the supply side resource stack detailing the results of the levelized cost analysis. He pointed out that levelized costs are being presented in two ways. First, the 30-year levelized cost of production figures represent all fixed and variable costs of the resource spread over some stated level of output. The 30-year levelized capacity costs include only the fixed costs of the resource (namely cost of capital and fixed operating costs) stated as a function of the assumed nameplate generating capacity. Mr. Henderson explained that levelized costs were calculated from a traditional revenue requirement (ratepayer) perspective. Levelized costs included emission adders for fossil fuel technologies, various tax incentives for renewables, and a wind integration adder of \$6.50/MWh.

Mr. Henderson mentioned that 25 specific resources were analyzed, with wind, geothermal and gas generation being the only large-scale commercial generation that is technically and economically feasible over the next five to eight years. Commercial solar costs are coming down due to tax incentives; nevertheless a realistic timeline for development of large-scale solar in southern Idaho is at least six to eight years out. Advanced coal and nuclear landed near the middle of the cost stack; however due to construction lead times, cost uncertainty and technological risk, these resources really cannot be considered in a resource portfolio until at least 2020. Lastly, Mr. Henderson pointed out that small-scale generation such as biomass, and low-drop hydro fared reasonably well in the resource stack, but would likely come to Idaho Power as PURPA projects if they prove to be economical. Mr. Henderson concluded by pointing out the significant increase in levelized resource costs since the 2006 IRP. Additionally, he stated it is unlikely that commercial generation can be developed for much less than \$100/MWh on a levelized cost basis.

Mr. Miller asked for clarification regarding the distributed generation resource. Mr. Henderson responded by saying the term "distributed generation" and "virtual peaker" are assumed to be one in the same. Mr. Henderson characterized distributed generation as interconnected/dispatchable backup emergency generation near the load center. Due to emission concerns, a resource would likely be geared toward new installations fueled by natural gas.

Mr. Hawk commented that a significant portion of the capital costs for biomass (digester) exists due to regulation. Mr. Hawk stated the technology has the ability to capture the gas whether it is clean or not. He questioned the high operating costs for biomass and low-drop small hydro, and stated he does not believe geothermal is any cheaper than low-drop small hydro and would rank hydro and biomass cheaper than listed.

Suzanne Leta Liou requested that Idaho Power provide a detailed list of assumptions used for developing the levelized costs. Mark Stokes replied that a draft of the assumptions had been previously distributed. Mr. Henderson added that Idaho Power would redistribute an updated version in the near future.

Additionally, Ms. Liou expressed concern over the assumptions used to develop the natural gas price forecast and the fact that Idaho Power has not identified the risks surrounding the long-term purchase of natural gas (cannot lock in a price for 30 years). Idaho Power will address the natural gas price risk within the risk section of the IRP. Ms. Liou requested Idaho Power to consider written comments regarding natural gas and the suggested method to determine the cost of a combined-cycle plant.

Average Energy and Peak-Hour Deficits – Phil DeVol

In his introduction, Mr. DeVol described the surplus/deficit analysis as a simple comparison of forecast load to forecast generation, where forecast generation includes not only output from company-owned resources but also power purchased through long-term contractual agreements and shorter-term wholesale markets. It was emphasized that one of the primary objectives of the IRP process is to identify periods for which forecast generation is in deficit relative to forecast load. For these periods existing resources are considered inadequate.

Mr. DeVol explained that resource adequacy for the surplus/deficit analysis is evaluated from two perspectives. The average energy perspective considers whether the aggregate amount of generation forecast for a month meets the aggregate amount of forecast load, where the hydro component of the forecast generation assumes a drier than normal streamflow condition (70% exceedance level) and load is assumed at higher than median levels. The intent of the peak-hour analysis is to assess adequacy of the maximum generating capability for a given month from the perspective of the peak-hour load. The peak-hour analysis assumes streamflow conditions at a 90% exceedance level and peak-hour load at a 95% exceedance level.

To illustrate the surplus/deficit levels, Mr. DeVol used a series of graphs picturing the forecast load being progressively met through the addition of resources available to the current system (DSM, coal, hydro, CSPP/PPA, etc.). These illustrations depict energy deficits in summer and winter months (primarily July, August, and December) until the addition of committed baseload generation and transmission resources in 2012-13, and only summertime deficits after 2013. Significant wintertime energy deficits didn't return until the 2020's in Mr. DeVol's illustrations. Peak-hour deficits were present in July until the committed resource additions of 2012-13, and returned as a result of ongoing load growth in 2017. In closing, Mr. DeVol explained that an objective of the resource portfolio design process is to select resources effective in eliminating the energy and peak-hour deficits.

Developing Sample Resource Portfolios – Tom Noll

Prior to introducing Tom Noll, Mark Stokes provided a brief update on the status of Idaho Power's efforts to acquire geothermal energy through the RFP process. Because of the uncertainty in developing geothermal resources, the RFP process has not worked well as a means to acquire geothermal resources. Mr. Stokes stated that Idaho Power continues to be interested in adding geothermal resources to its portfolio and would continue to work with developers as projects mature. Mr. Stokes went on to say that Idaho Power felt the best way to represent this in the IRP was to include small incremental amounts of geothermal energy in all the portfolios that are analyzed. After some general discussion regarding how much geothermal energy may eventually be available in Idaho, the group reached a general consensus that it would be appropriate to include small amounts at regular intervals in all the initial portfolios. Following this discussion, Mr. Stokes introduced Tom Noll to lead the discussion on the topic of developing sample resource portfolios.

Tom Noll presented two sample resource portfolios developed by Idaho Power. Tom explained Idaho Power assumes that two proposed projects will be constructed – the natural gas fired combined-cycle combustion turbine presently in the competitive RFP process (approximately 300 MW), and the Boardman-Hemingway transmission line (225 MW transfer capacity).

Mr. Noll started the discussion with an explanation of the load requirements faced by Idaho Power. The company faces severe peak deficits during the summer months of June, July, and August. During the remaining nine months of the year, Idaho Power's load and generation are generally balanced. Idaho Power faces difficult resource decisions because the summertime demand suggests the need for peaking resources, yet Idaho Power and its regulators prefer to pursue a balanced resource portfolio. Earlier in the day, Cory Read presented the company's demand-side programs directed at reducing summertime demand.

The first sample portfolio presented by Mr. Noll was an extension of the blended portfolio developed in the 2006 Integrated Resource Plan. This portfolio contains 150 MW of wind online in 2012, two 170 MW simple-cycle combustion turbines (2015 and 2021), a 60 MW upgrade to the Lolo-Idaho Power transmission path in 2019, and limited amounts of geothermal generation. Baseload generation and a new peak resource after 2021 are also included in this portfolio. The portfolio will bring the quantity of wind generation on the Idaho Power system to approximately 500 MW which may be the limit of wind generation that can be practically integrated on Idaho Power's system.

The second sample portfolio primarily consisted of wind generation and simple-cycle combustion turbine peaking generation. The second portfolio was an example of using wind and supplemental combustion turbines to meet Idaho Power's requirements. Mr. Noll also pointed out that the second portfolio was not very diverse as it relied heavily on only two types of supply-side generation resources.

Several additional topics were discussed during the portfolio presentations:

Carbon Adder Timing – The question was raised as to whether the carbon adder should be included earlier than 2012. Several comments were made suggesting legislation would be passed earlier than 2012, but in general the group felt 2012 was realistic for an implementation date.

Value of Renewable Energy Credits, Production Tax Credits, and Investment Tax Credits - Suzanne Leta Liou of RNP asked Idaho Power to consider the risks (load growth, hydro, carbon, gas prices, and wholesale electric prices) and the role that renewable generation can play in ameliorating the risks. There was additional discussion regarding the value of Renewable Energy Credits (RECs), Production Tax Credits (PTCs), and Investment Tax Credits (ITCs) within the portfolios.

Additional Portfolios - Participants offered numerous suggestions regarding specific resources such as PV solar, pumped storage, wind, nuclear, and geothermal. David Hawk requested that Idaho Power consider low head hydro projects (20-30 MW) through either PURPA or Idaho Power, as well as suggested that Combined Heat and Power (CHP) be included in the portfolios. Kevin Kitz requested that small increments of geothermal generation be kept in the portfolio as a placeholder.

Meeting Wrap-Up and Summary – Mark Stokes

Mr. Stokes announced the next meeting would be on January 22nd. He stated he would e-mail initial portfolios to the IRPAC prior to the next meeting in order to get comments back before beginning the analysis work. Mr. Stokes then asked the group if there were any additional comments or questions, which there were none. Mr. Stokes then thanked everyone for attending and adjourned the meeting.