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IDAHO PUBLIC UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF PACIFCORP DBA ROCKY MOUNTAIN POWER'S 2013 INTEGRATED RESOURCE PLAN	CASE NO. PAC-E-13-05 IDAHO CONSERVATION LEAGUE COMMENTS

The Idaho Conservation League (ICL) submits the following comments on Rocky Mountain Powers (RMP) Integrated Resource Plan. ICL's comments cover three main topics: modeling/process issues, resource assumptions, and coal pollution controls.

I. Modeling/Process Issues

A. Carbon price forecast

The risk of future carbon regulations imposing additional costs on RMP continues to grow. Assigning a future carbon price to account for this risk is a fundamental step in assuring a least cost-least risk result. A forecast carbon price serves as a useful proxy for future carbon regulations regardless of the mechanism -- cap and trade, a tax, direct pollution controls. While the specific policy mechanisms remains on clear, the likelihood of some federal controls is inevitable. Unfortunately, RMP's forecasted carbon prices are unreasonably low there by exposing ratepayers to higher risk resource decisions.

RMP uses a zero carbon price option, and in fact chooses a portfolio that assumes zero carbon prices over the planning horizon. Regardless of whether it is legislation or administrative it is unreasonable to assume zero carbon costs. Also, RMP's "base" and high" forecast are unreasonably low. Synapse Energy Economics reviews all relevant legislative proposals and carbon forecasts to determine a range of future carbon prices. In August of 2012, ICL and our regional allies submitted Synapses 2011 forecast report to RMP. In 2012, Synapse slightly lowered the forecast carbon prices beginning 2020 at with low, mid and high prices at $15, $20, and $30 and escalating to $25, $42.50, and $70 by 2030.[1]

Meanwhile RMP assumes a much lower forecast with explaining the source of these numbers. First, RMP assumes a low and mid range forecast that does not begin until 2022. Second RMP assumes a low, mid, and high prices of $0, $16, and $26. Essentially, RMP's "base" case is equivalent to Synapses "low" forecast and RMP's "high" case is equivalent to Synapses "mid" forecast. Because carbon prices are a significant driver of evaluating coal plant retirement or upgrade scenarios, using an arbitrary and unexplained discounting of future carbon prices can expose customers to substantial risk. The Commission should be skeptical of RMP's modeling results that presume zero carbon costs, and infer additional risk onto portfolios that assume a medium carbon costs.

B. Reporting of capacity deficits

RMP calculates the scale of potential capacity deficits but does not provide the time frame. For instance, Figure 5.2 shows a system capacity resource gap of 824 MW in 2013.[2] But the IRP does not indicate whether this gap occurs for one hour in the year, or 100 hours. Identifying both the size and time of the resource gaps allows for a better assessment of the least cost-least risk resource necessary to meet this need. For example, figure 5.5 shows the average monthly and annual energy position.[3] By showing both the size and timing, this figure reveals the resource gap is only for a couple months instead of throughout the year. If RMP provided this same format for capacity deficits customers and regulators would know if a demand response product available for 40 hours a year is a better fit than a simple cycle turbine available 8650 hours a year. Going forward, ICL recommends the Commission require RMP to show capacity deficits by both size and timeframe.

II. Resource Issues

A. Energy Efficiency

A key hurdle in Integrated Resource Planning is fairly evaluating demand-side and supply side-resources. ICL endorses RMP's process: (a) defining three classes of DSM--load control, energy efficiency, rate designs; (b) creating supply curves for each resource type including 27 cost-defined bundles of efficiency measures; and (c) treating the supply curves "like discrete

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[1] Synapse Energy Economics 2012 Carbon Price Forecast at 4. Available at: http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf

[2] Pacificorp/Rocky Mountain Power 2013 Integrated Resource Plan (IRP) at 100.

[3] IRP at 103.

supply-side resources in the IRP modeling environment."[4] This process allows defined DSM measures to compete with supply side resources in a more realistic sense.

This IRP shows that when DSM is allowed to complete energy efficiency measures "are prevalent among all portfolios and play a significant role in meeting projected capacity and energy needs throughout the planning horizon."[5] Along with increased reliance on market purchases, RMP concludes reliance on DSM resources is "cost effective among a wide range of scenarios."[6] Pursuing resources that prove least cost and least risk across a range of uncertain future scenarios is a prudent course.

At the request of ICL and regional allies, RMP also modeled an accelerated DSM portfolio.[7] In this portfolio, instead of the DSM supply curves, the model achieved up to 2% of retail sales through energy efficiency measures. Even assuming high costs for incentives, the accelerated DSM portfolio is consistently the least cost-least risk option.[8] Top preforming utility DSM programs in the Rocky Mountain region achieve 1.4 – 1.5% of sales[9] and by pursuing best practices from these programs achieving 2% is a reasonable target.

While accelerated DSM out preformed all other portfolios RMP rejected their own results. Instead, RMP choose a portfolio (C7) justified upon a zero carbon prices. Assuming zero cost of carbon over a twenty-year horizon may be a reasonable modeling exercise. But choosing to pursue resources options, and spend ratepayer dollars, in reliance that carbon will never have a cost is unreasonable and risky.

RMP's specific reasons for rejecting the top preforming accelerated DSM portfolio are unpersuasive. The Company argues they "do not have strong evidence in support of the true acquisition costs" of accelerated DSM. [10] But the IRP reveals no attempt to find this evidence, or even discuss the tipping point of when increased acquisition costs would make the portfolio no longer the top performer. Second, RMP claims they do "not have strong evidence that the revised ramp rate assumptions are achievable. Again, the IRP does not discus any specific barriers, identify means to overcome these barriers, or even disclose that current programs in the

[4] IRP at 142
[5] IRP at 205
[6] IRP at 202.
[7] IRP at 151. This portfolio is number C15.
[8] IRP at 212 – 221.
[9] SWEEP, *The $20 Billon Bonanza, Best Practice Electric Utility Energy Efficiency Programs and Their Benefits for the Southwest*, at vi (October 2012) available at: http://www.swenergy.org/programs/utilities/20BBonanza.htm
[10] IRP at 222.

Rocky Mountains achieve around 1.5% of sales leaving only a 0.5% gap to close. A handful of sentences to reject the top preforming portfolio without providing any documentation is unreasonable and inadequate.

RMP's third reason to reject the top preforming accelerated DSM portfolio is baseless. The Company claims it is unreasonable to consider a portfolio that excluded combined cycle gas plants.[11] But over the first ten years of the planning horizon "none of the portfolios include a CCCT resource."[12] And DSM resources dominated in every other portfolio. So even if the accelerated DSM options allowed for combined cycle resources there is not apparent reason the model would have selected them. There is no evidence that excluding combined cycle gas plants from the accelerated DSM portfolio affected the model results.

RMP's action plan does identify some specific steps to increase DSM acquisition. But Idaho misses out or is last in line for these opportunities. RMP plans a pilot with Oregon on home comparison reports, but does not explain why it will no offer this to other states. Many other action items aim to roll out or expand programs in Utah in early 2014, but not in Idaho until late 2014 or 2015. Because the two service territories are closely aligned geographically, economically, social, and in media markets the Idaho Commission should expect RMP to pursue DSM programs in Idaho in parallel with Utah.

RMP's 2013 IRP shows that demand side resources, particularly energy efficiency measures, are cost effective across a wide range of future scenarios. DSM measures help keep bills down for consumers, defer supply side resource needs, help mitigate the risk of RMP's plan to rely more on volatile market purchases gas prices. Instead of rejecting these benefits, RMP should focus on achieving the accelerated energy savings that is the true least cost-least risk option.

B. Distributed Solar Assumptions

ICL is encouraged RMP plans to continue developing the Utah Solar Incentive Program targeting 60 MW of distributed photovoltaic (PV) systems by 2017.[13] RMP calculates the base capital costs of distributed PV in Utah as $902/kw.[14] In Idaho, that same capital costs jumps to $4,693/kw. This difference highlights a fundamental flaw in how RMP assess the costs of

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[11] IRP at 222.
[12] IRP at 222.
[13] IRP at 139.
[14] IRP at 126.

distributed PV resources. In Utah RMP correctly assumes the system owner supplies the costs of installing the system – precisely how current rooftop solar system work.[15] But in other states RMP assumes the utility pays the entire capital costs – an irrational assumption. A prime benefit of distributed PV systems is that individual customers provide the upfront capital costs, not the utility. All distributed PV resources should be analyzed as RMP does in Utah, not Idaho or their other territories.

C. Transmission Assumptions

Despite planning to rely increasing on energy markets through "front office transactions" RMP does not discuss how changes to transmission scheduling will affect future resource needs, costs, or system operations. For instance, FERC Order 764 requires transmission providers to offer 15-minute schedules within each operating hour. This change should reduce the cost of integrating variable energy and allow utilities to create new balancing products to maximize system resource value and reduce purchased power costs. Despite these potential benefits, and a compliance deadline of November 2013, the IRP does not discuss how RMP will position itself to maximize value and reduce risks to customers in this changing transmission landscape.

RMP does disclose they will continue to pursue an Energy Imbalance Market with the California ISO.[16] ICL encourages RMP to follow this path. However, as this market develops RMOP should reevaluate the potential demand response options in the service territory to develop opportunities for customers to directly benefit from this changing market place.

III. Coal Plant Upgrades

RMP faces significant costs to meet future pollution control standards for the coal fleet. But the IRP inaccurately accounts for the costs and risks of these forthcoming costs. For example, RMP claims that the model accounts for potential future compliance costs and existing coal plants and can choose to retire plants instead of comply.[17] But it is not at all clear or transparent if RMP is actually including a reasonable forecast of compliance costs. ICL joined with our regional allies in a letter, sent June 21, 2013, discussing this issue in detail. A copy of this letter is attached to these comments as Exhibit A. The bottom line is that RMP's assessment of future pollution controls is artificially low. More specifically, for the Jim Bridger plants RMP claims to

[15] IRP at 124.
[16] IRP at 50.
[17] IRP at 4.

have a more detailed financial analysis. But due to the time constraints of the IRP review process ICL and other stakeholders are unable to test the accuracy and robustness of this analysis. Because the assessment of future controls is untested and in many respects fundamentally flawed the Idaho Commission should specifically note that RMP may not rely on this IRP to justify any coal plant investments.

Along with inaccurate costs, RMP does not allow a reasonable range of resource alternatives to compete against coal. RMP selects two alternatives; repower the plant with gas, or replace MW for MW with new gas. A far better approach is to use the integrated system to determine resource needs, rather than arbitrarily pick a replacement. This is a three step process: first, remove a single unit from the current resource portfolio, Second, run the models to identify the resource gaps that result. Third,, select specific resources to match these gaps. For instance, removing Bridger Unit three from the resource stack may reveal capacity deficits in June, July, and August of say 300 MW. The least cost-least risk resource could be something other than repowering with gas. Until RMP preforms this kind of unconstrained resource assessment, the IRP is incomplete.

DATED this 8th day of August 2013.

Respectfully submitted,

Benjamin J. Otto
Idaho Conservation League

CERTIFICATE OF SERVICE

I hereby certify that on this 8 th day of August 2013, I delivered true and correct copies of the foregoing COMMENTS to the following persons via the method of service noted:

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Powder River Basin Resource Council * Sierra Club * HEAL Utah
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June 21, 2013

Idaho Public Utilities Commission
Utah Public Service Commission
Oregon Public Utility Commission
Wyoming Public Service Commission
Washington Utilities and Transportation Commission
California Public Utilities Commission

RE: PacifiCorp's 2013 Integrated Resource Plan

Dear Commissioners:

Our organizations are writing to express concerns about the scope of analysis in PacifiCorp's 2013 Integrated Resource Plan (IRP) that the company submitted to you at the end of April. Specifically, we have significant concerns about the scope of PacifiCorp's analysis related to reasonably foreseeable coal plant costs and how those costs relate to electric generation options of the company in both the short and long term.

On May 23, 2013 the U.S. Environmental Protection Agency (EPA), through its regional office in Denver, issued a draft proposal related to implementation of the regional haze rule in Wyoming. The regional haze rule requires Best Available Retrofit Technology (BART) pollution controls at ten PacifiCorp coal units in Wyoming and additional pollution controls at two older coal units as part of the long-term strategy to reduce haze-causing pollution.

We understand the difficulties inherent in assessing yet-to-be-finalized government regulations. However, forecasting liability, such as the liability created by the regional haze rule, is a paramount part of properly being able to select resource choices that will be the least-cost, least-risk for customers.

In the case of the PacifiCorp IRP and its related coal study, the company completely missed the mark. Despite knowing about the range of potential pollution controls that EPA was evaluating as part of its regional haze rulemaking process, PacifiCorp did not consider selective catalytic reduction (SCR) controls for nitrogen oxide emissions at three of its units and selective non-catalytic reduction (SNCR) controls at one other unit in the near term. To help explain the situation, here is what was analyzed versus what will be required:

Coal Unit	NOx Control Technology Analyzed in the IRP	NOx Control Technology Required by the EPA
Naughton Unit 1	No additional controls	SCR in 2018
Naughton Unit 2	No additional controls	SCR in 2018
Dave Johnston Unit 3	SNCR in 2017	SCR in 2018
Dave Johnston Unit 4	No additional controls	SNCR in 2018

Regrettably, PacifiCorp's failure to consider the possibility that these costs would be foreseeable came as a result of willfully ignoring the advice and comments of our organizations. On at least three occasions throughout the stakeholder engagement process, Powder River Basin Resource Council and others asked PacifiCorp to consider a more stringent regional haze scenario where SCR would be required on additional coal units. Organizations told the company that they believed this would be a reasonably foreseeable outcome of EPA's action and should therefore be analyzed. The company refused. Now that EPA has in fact recommended these pollution controls, PacifiCorp's IRP in regards to a significant portion of the coal fleet is fundamentally flawed.

The costs of these pollution controls are important to analyze both in the context of the individual coal units but also in the context of the company's entire coal fleet. Neither the unit specific nor the cumulative economic analysis for these possible expenditures was conducted as part of the company's IRP. As a result, PacifiCorp's IRP does not include an accurate accounting of the likely additional capital investments required to operate these plants.

Our organizations will be participating in the IRP public comment and hearing processes in each of our respective states. However, we wanted to send this joint letter to all of the Commissions to let you know about this serious flaw in the IRP in the hope that you will be able to address it as soon as possible.

To the extent that the timing does not allow for a request for additional analysis from the company, we ask that you take action to not acknowledge any portions of the IRP related to coal plant expenditures and future resource allocation choices until such time as PacifiCorp remedies its analysis.

Thank you for your time and attention.

Sincerely,

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