BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 62

In the Matter of	)	
PACIFICORP dba PACIFIC POWER	)	OPENING COMMENTS OF THE
2015 Integrated Resource Plan	)	NW ENERGY COALITION
	)	

The NW Energy Coalition (Coalition) appreciates the opportunity to provide comments regarding PacifiCorp's (Company) 2015 Integrated Resource Plan (IRP). The Coalition participated in the pre-IRP workshop phase conducted by the Company for almost a full year before filing the IRP. The Company continues to achieve considerable improvement in the public process portion of IRP development. Extensive discussions and willingness to incorporate stakeholder suggestions ultimately led to a stronger draft IRP.

I. Introduction

Overall, the 2015 IRP submitted by the Company is impressive. The Company is making important strides in its demand side management programs across all states in the service territory. Improvements to the demand side management potential assessment led to higher levels of energy efficiency selected in the preferred portfolio. Additionally, the Company provided extensive analysis related to carbon regulation – in particular the Environmental Protection Agency's (EPA) proposed Clean Power Plan [111(d)].

Despite this progress, there are a few areas of concern with the current IRP. For example, assumptions in the Company's modeling may be undervaluing the risk reduction values of physical compliance with state renewable energy mandates in favor of unbundled REC purchases. Additionally, solar resource costs may be too high, leading to an undervaluing of these resources in the IRP. While the company is considering coal phase out in a more comprehensive way, it does not appear that the retirements indicated in the preferred resource portfolio will be enough to meet Oregon's climate goals. Further, the preferred portfolio leans very heavily on gas replacement in the later years and effectively has no new renewable resources for the entire 20-year planning period. The following comments provide praise for elements of the IRP that are particularly strong, and point out a few areas where there is room for improvement.

II. Demand Side Management

Over the last two years, since the filing of its 2013 IRP, the Company has responsibly implemented its demand side management acquisition programs – exceeding the goals established in the IRP for those years. The aggressive action plan for DSM in the 2013 IRP is being followed, with most actions already completed. The Company should be commended for their implementation of strong DSM programs over the last couple of years.

Additionally, improvements to the conservation potential study methodology led to a significant increase in DSM goals contained within the 2015 IRP. Aggressive achievement (or perhaps even overachievement) of these IRP goals will save the Company and ratepayers money by displacing the need for higher priced front office transactions.

Unfortunately, the Company eliminated the inclusion of detailed action plan items in the IRP, leaving less specificity for how programs will achieve these new, higher goals. Nonetheless, the Coalition looks forward to working with the Company to monitor and encourage continued progress in setting and achieving high DSM goals in all states.

III. Coal Resource Analysis

Over the last several years, the Coalition, in its 2011 and 2013 PacifiCorp IRP comments submitted to this Commission, criticized the Company's coal analysis on the basis that it was insufficient to identify the least cost strategy for customers. In the 2015 IRP, we find that the Company has made good progress in improving its coal resource analysis methodology.

The Company engaged in meaningful dialog with stakeholders during the 2015 IRP development process to significantly improve its coal analysis and, in particular, its analysis of EPA regional haze compliance requirements on coal burning units. As a result, the Company is finding that in some cases the capital costs associated with installing required emission control equipment are not cost effective over the remaining life of the units.

In fact, the analysis is now showing that converting Naughton Unit 3 to burn natural gas and strategies that avoid installation of selective catalytic reduction (SCR) equipment at Wyodak, Dave Johnston Unit 3 and Cholla Unit 4 will save customers "hundreds of millions of dollars." (IRP, pg. 6) The Coalition looks forward to working with the Company to ensure that going-forward coal analysis methodology continues to improve in order to ensure the most economical decisions for customers.

IV. Carbon Regulation and Pricing

Carbon policy going forward is clearly a key focus of the PacifiCorp IRP process. The IRP focuses on the proposed EPA Clean Power Plan, which is now issued in final form, and the many questions about the direction states will take with their implementation plans. However, the IRP also recognizes that the Clean Power Plan is not the only policy that could impact carbon-emitting sources over the span of this IRP timeline.

The California AB 32 cap-and-trade market now extends to most of the state economy and has had a notable effect on the power markets there and in the west, in effect putting an initial shadow price on carbon region-wide. In Oregon and Washington, debate continues on adopting state carbon pricing policies. And ongoing questions continue concerning the policy on supply chain methane emissions from exploration, production, transportation and distribution of natural gas for direct use and for power plants.

PacifiCorp has done a better job in the 2015 IRP considering these complex factors. The already complicated IRP modeling framework has been augmented to accommodate Clean Power Plan assessment, and the Company responded to stakeholder input on carbon risk and trigger point analysis. The Company should be commended for their extensive analysis of the EPA's Clean Power Plan [111(d)] draft regulations.

One major flaw in the Company's approach to modeling the impact of EPA's Clean Power Plan is the assumption related to renewable resources. The Company assumes in modeling for this IRP that renewable energy credits (RECs) or the renewable attributes associated with renewable energy generation, could be used in one state to comply with a renewable energy mandate, and then applied to Clean Power Plan compliance *in another state*. This interpretation could potentially lead to double counting of RECs and it seems unlikely that the final EPA rules would allow anything of the sort. This assumption fundamentally alters the cost and risk of different RPS compliance options and more analysis should be completed in the IRP update incorporating the EPA final rules.

Another concern is that any regulatory framework or implementation decisions by individual states that limit multi-state collaboration will result in a different regulatory future than the Company assumes in the bulk of their IRP 111(d) assumptions. If one or more of the states in the Company's service territory decide to implement the regulations solely on a state basis, the regulation will take on a different dimension and it will be potentially more challenging for the Company to comply based on the preferred portfolio selected within this IRP. This is yet another justification for a more complete analysis of Clean Power Plan compliance options in the IRP update.

Additionally, in the preferred resource portfolio total CO2 emissions fall from 50 million tonnes per year in 2015 to about 40 million in 2023, and then stay flat to 2034. While this may be a significant portion of emissions reductions under eventual state implementation plans for the Clean Power Plan, it is not sufficient to track the long-term climate targets in Oregon and Washington, or broader global and national goals suggested by the IPCC Fifth Assessment Report, National Climate Assessment and many other similar studies.

V. Renewable Resources

The 2015 IRP is most notable for its near-complete lack of new renewable energy over not only the 4-year action plan period but also the full 20-year planning horizon. In fact, the proportion of renewable energy actually falls from 9% currently to 7% in 2034 for the preferred portfolio. Almost all projected activity, aside from a 7 MW solar procurement under Oregon requirements, amounts to reshuffling RECs to satisfy RPS requirements in the most limited way, which may be under-valuing the long-term risk reduction benefits of physical compliance.

The overall outcome of almost no new renewables over both the near term and 20-year period does not seem at all reasonable, given the substantial amount of new resources that will be needed, even considering more limited load growth and more effective levels of DSM, the ongoing decline in renewable energy costs, and the very modest levels of coal retirements in the draft.

More renewable energy would be included in both the long term and action plan (especially pilot program and development efforts), if IRP results considered a more realistic high gas price risk, faster coal retirement and earlier onset of carbon prices going forward, and the potential for improving renewable energy system value in conjunction with rapidly falling costs for complementary storage.

For a clear illustration of the consequences, refer to Figure 8.25 (p. 193). This shows the current and preferred portfolio resource mix (on an energy basis) changing as follows:

Resource	2015	2034
Coal	61%	31%
Gas	14%	41%
DSM+DR	8%	15%
Renewable	9%	7%

Not including FOT and other categories.

While we appreciate the company's effort to take future renewable energy potential more seriously in this IRP, including a better study of future potential by Navigant, there are a couple of specific areas of concern with the renewable energy actions plan in the IRP.

A) <u>REC's vs. Physical Compliance to I-937</u>

The Company's decision to comply with Washington's RPS with unbundled RECs may be shortsighted. The Company has shown that at current prices unbundled RECs offer a low cost compliance option; however, the risk benefits of physical compliance, especially in consideration of EPA's pending Clean Power Plan regulations and other potential state carbon regulation, may be under-represented in the analysis performed for this IRP. The

Company's plan to physically comply with I-937 using unbundled RECs should be reexamined in an IRP update, in accordance with the final Clean Power Plan rule.

B) Solar Costs

The estimated future costs for solar are a particular concern. For medium and large scale solar PV, the base levels shown in Figure 7.9 indicate current costs (for 5 MW fixed tilt) at about $3,100/kw-ac at present and declining slowly to about $2,500 in 2024 – there are projects coming in today at that level. And beyond 2024, the base level stays flat until 2034.

For small scale and distributed renewable energy, the base level analysis is slightly improved over the 2013 IRP but still falls short. For example, even using the moderately aggressive new solar PV costs proposed by the Coalition and other stakeholders (Sensitivity case S-12, see Figure 7.9 and 7.12, pp. 151 and 154), results in no more than 500 aMW of new solar, less than 5% of total system resources, by 2034. We believe further analysis including a more realistic high gas forecast and the effect of affordable local storage will substantially boost the results.

B) Natural Gas Price Forecast

The natural gas price forecast is a key driver for IRP modeling because it basically sets the reference level for selection of other resources into the preferred portfolio or a given sensitivity case. It strongly influences the cost of front office transactions as well as the fuel cost for gas baseload, swing and peaking. Historically gas price forecasts have had a low level of accuracy and the record since full price deregulation in the early 1990s is replete with short-term volatility and major shifts in trends.

Short term volatility remains: gas price is also highly sensitive to seasonal factors, especially winter weather in the US east and Midwest, inventory levels, and the relative cost of substitutes such as coal for power plants. These are trend drivers for consideration of the influence of gas prices on the western power markets and economic unit dispatch, and PacifiCorp has a very sophisticated analysis of those interactions based on historical data and stochastic modeling. In the context of the IRP, however, the longer-term trends affecting both the 20-year preferred resource portfolio and the 4-year action plan period are very powerful, and here the picture is far cloudier. Thus, the Official Forward Price Curve is just one of several factors that must be considered in assessing the role of gas in the PacifiCorp resource mix going forward.

Other long term key drivers include well decline rates, gas market demand structure, separation of North American and world gas prices (as LNG export starts and expands, if export netback margins continue to exceed domestic sale margins then there will be considerable upward price pressure), improving exploration and production efficiency, relative costs (energy efficiency, coal, renewables and storage), and future carbon price and regulation.

The current mid-period high gas forecast is about $6.50/mmBtu in 2024 (Figure 7.15). Even that level shifts the resource mix to a notable degree. But we believe this high gas level is too optimistic, and a high case of $8.00 or more may be warranted to accommodate all the upward price risks reviewed here.

We put forward this overview to make the point that focusing on the Official Gas Price Forecast, based as it is on the best of the national models but having their known limitations, is only of the key consideration for gas risk in the 2015 IRP.

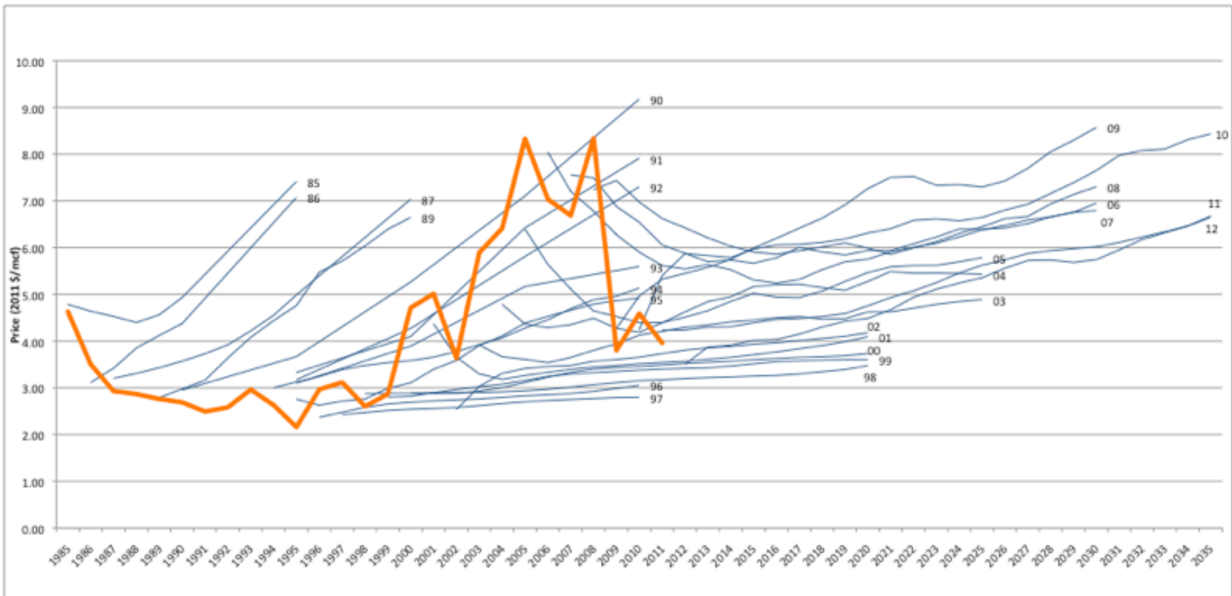

Figure: U.S. Energy Information Administration forecasts of U.S. wellhead natural gas prices, adjusted for inflation, in various years (blue lines) compared with actual prices (orange line).
Source: Rocky Mountain Institute

We recommend that the Commission urge the Company to review and improve its methodology for including natural gas price uncertainty and risk in IRP modeling in the next IRP.

VI. Transmission

PacifiCorp's Energy Gateway is a very large and complex transmission development program. While the benefits could be substantial, if all remaining parts are fully constructed, they would add about 10% to PacifiCorp's existing 16,000 miles of high voltage transmission and overall costs could exceed $5 billion (with some costs shared by other owners).

There are two major developments in the 2015 IRP. The Company is pulling Gateway West off the track toward acknowledgment at least for the time being (although siting review is continuing). And Boardman-to-Hemingway (B2H) has now been added to the Energy Gateway development package (with Idaho Power as primary sponsor and additional participation by the Bonneville Power Administration).

The context for these changes includes a flattening of the demand forecast and resulting removal of new renewable energy from the preferred resource portfolio. Reliability, operational factors and changes in requests for interconnection from new renewable projects are also in play, as well as the oncoming Clean Power Plan, state climate policy, and the proposal for PacifiCorp to become a full member of the California ISO.

We believe now is a good time to step back to reassess how transmission is considered within the IRP process. Key aspects include coordination of the scale and location for new renewable energy to reuse existing transmission as coal is retired, and to build new transmission to high-value renewable areas that don't have access.

Additionally, two other points are increasingly important. First is more explicit consideration of non-wires alternatives, especially at the grid edge (DSM, distributed generation, demand response, storage, power electronics providing ancillary services). Second is how to coordinate new transmission where numerous adjacent systems have overlapping needs (PacifiCorp, Idaho Power, Bonneville, Puget Sound Energy, Avista, PGE, Northwestern).

The stakes are high: billion-dollar-plus transmission projects could leverage multi-billion dollar investments in zero-carbon generation, and capture the diversity value of a wider range of technologies (wind, solar, biomass, geothermal) and geographic reach.
The draft IRP has evidence of early steps in the right direction. PacifiCorp recognizes the potential for reusing existing transmission with coal retirement: "In addition, if a comparable resource is selected immediately after a unit retires, there may not need to be costs to reinforce the existing transmission resource in the area, otherwise, additional costs would need to be incurred to maintain reliability of the transmission system."(p.128)

Additionally, PacifiCorp's initial participation in the CAISO energy imbalance market is opening up opportunities for "a reduction in reserve carrying requirements, transmission improvements to mitigate congestion and greater reliance on renewable energy." (p. 44)
A very important new development is the April announcement that PacifiCorp intends to become a full participating member of the CAISO. This would have profound implications for transmission planning and cost allocation.

As a result, we recommend that the next IRP should engage a reassessment of the Energy Gateway transmission strategy. While we acknowledge the Company's time and resources already invested in the effort, however, the stakes and the costs are so substantial that it warrants stepping back and looking at the whole picture.

Respectfully submitted this 27th day of August 2015,

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