BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the 2006 PacifiCorp	)	
Integrated Resource Plan	)	Docket No. 07-2035-01
	)	

COMMENTS OF WESTERN RESOURCE ADVOCATES, UTAH CLEAN ENERGY AND THE SOUTHWEST ENERGY EFFICIENCY PROJECT ON PACIFICORP'S 2007 IRP UPDATE

I. PACIFICORP 2007 IRP UPDATE

Western Resource Advocates, Utah Clean Energy and the Southwest Energy Efficiency Project appreciate the opportunity to provide input to the Public Service Commission of Utah ("Commission") regarding PacifiCorp's 2007 Integrated Resource Plan Update ("Update").[1] Given the significant uncertainty surrounding CO2 regulation, the future level and volatility of gas and market electricity prices, and the speed with which new technologies can become commercially viable, sound utility planning is more important than ever to address environmental necessities while mitigating the risks to the utility and its customers.

PacifiCorp's 2007 IRP ("IRP 2007") did not receive acknowledgement. In its Order issued February 6, 2008 the Commission identified four guidelines that the IRP did not meet: "consideration of all resources on a consistent and comparable basis, a link to the strategic business plan to ensure customer benefits from IRP, the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty, and different resource acquisition paths to select among and modify these paths as the future unfolds."[2] Importantly, the Update does not address these deficiencies.

Business Plan Portfolio

To develop the Business Plan portfolio, PacifiCorp updated certain of its assumptions. These included estimates of achievable energy efficiency and other components of the load and resource balance as well as wholesale market electricity and natural gas prices.

[1] Utah Code §54-17-302 requires the Commission to review any action plan filed by the Company as part of its IRP and provide guidance to the Company. PacifiCorp filed an updated integrated resource plan (IRP) with an updated action plan on June 11. As a result the Commission noticed a scheduling conference and set September 10 as the deadline for submitting comments. Reply comments are due October 9.

[2] Public Service Commission, *Report and Order* In the Matter of the PacifiCorp 2006 Integrated Resource Plan, Docket No. 07-2035-01, February 6, 2008, p 44.

The changed load and resource assumptions reduced the need on the east side by approximately 200 MW over the 2010 to 2016 time period and increased the need on the west side by roughly 245 MW over the same period. Overall, system need increased slightly.

As was done in IRP 2007, PacifiCorp predetermined the level of renewables and DSM outside of the IRP modeling. (It also predetermined incremental transmission). It then constrained pulverized coal and IGCC as resource options prior to 2018. PacifiCorp used its capacity expansion program, System Optimizer, to optimize gas additions and short-term market purchases to meet a 12% planning reserve margin. Cost and risk metrics for the resulting plan—the Business Plan—were not provided.[3]

We strongly support PacifiCorp's decision to avoid new pulverized coal units, and agree with the qualitative analysis PacifiCorp uses to explain its decision to constrain coal until 2018.[4] Moreover, as we discuss in Section II of these comments, we believe that if the risk associated with new conventional coal-fired generation is properly modeled, the IRP would provide additional analytical support for the Company's decision to avoid pulverized coal, not only over the ten years reflected in the Business Plan but on a forward basis.

While we strongly support the Company's decision to remove new conventional coal-fired generation from its Business Plan, we believe there are additional areas where the plan can be improved from a least cost, least risk perspective. In particular, the plan appears to be market heavy at the expense of additional energy efficiency and renewables—the resources that best mitigate the risks of carbon regulation and the level and volatility of wholesale electricity market and natural gas prices.

As discussed in our original set of comments in this docket, renewable resources can fulfill energy and capacity obligations with no incremental risk associated with the price or availability of fossil fuels or CO2 emission allowances. These resources were prescreened in the IRP 2007 process and remain excluded in the Update.

Energy Efficiency

PacifiCorp has increased the amount of DSM it assumes will be achieved during 2008-2012 by about 50% relative to the levels in the 2007 IRP. We believe this is a good beginning, but the total energy savings from DSM programs still appears low – 450 GWh/yr from programs in 2010 and 486 GWh/yr from programs in 2012. These values, in terms of percentage of retail sales, are well below the level of cost-effective energy savings that other leading utilities are already achieving or planning to achieve in the near future. Also, they are inconsistent with the level of energy savings that the Energy Trust of Oregon (ETO) is now planning to achieve.

---

[3] With respect to the IRP 2007 portfolio, the Business Plan portfolio is 662 MW smaller.[3] It has two fewer coal units and one less gas unit. Wind acquisition is 30 MW smaller. Class 1 DSM is 69 MW smaller. Energy efficiency estimates are higher and short-term market transactions are significantly increased, particularly after 2012.[3] The Business Plan includes an average of 461 MW more short-term market purchase than the previous plan over the 2008-2016 timeframe and an average of 673 MW more over the 2012-2016 timeframe. From 2012 to 2016, the Business Plan includes nearly 1200 MW of short-term transactions annually to meet firm load projections.

[4] PacifiCorp, 2007 Integrated Resource Plan Update, p. 17.

The savings levels mentioned above represent 0.71% and 0.74% of the total load forecast in 2010 and 2012, respectively. Other utilities with comprehensive, well-funded DSM programs in the western region are achieving higher energy savings. Pacific Gas &Electric (PG&E) and Southern California Edison achieved savings of around 1.5% of sales per year as of 2005, and San Diego Gas and Electric Company saved even more.[5] Investor-owned utilities in Nevada expect to save about 0.9% of their 2006 sales (roughly 0.85% of 2008 sales) from DSM programs implemented in 2008.[6] Xcel Energy has proposed saving 1.1% of sales from its DSM programs in Minnesota starting in 2009 and is also ramping up its DSM programs in Colorado. Xcel has proposed spending about $60 million on DSM programs and reducing electricity demand in Colorado by about 0.83% as of 2010.[7] Seattle City Light recently issued a new DSM plan that calls for the utility to ramp up DSM programs and reduce electricity use by 1.4% per year by 2011.[8] The DSM programs of all these utilities must pass either the Total Resource Cost test or a societal cost test that includes some value for avoided pollutant emissions.

The Update does not break down projected savings from DSM programs by state. But with respect to Oregon, the Energy Trust of Oregon reports that as of 2008 it is saving about 1% of electricity sales from its programs each year, leading to flat overall electricity demand (*i.e.*, no load growth) in the state.[9] While Oregon represents only about 25% of the total load served by PacifiCorp, we believe the utility should be able to replicate or exceed what the ETO is now doing and thereby save 1% per year in the remainder of its service territory. Of course this is dependent on approval of new and/or expanded DSM programs in states such as Utah and Wyoming. In order to achieve greater energy savings, PacifiCorp should consider increased marketing, higher incentives, and additional program offerings based on DSM "best practices" throughout the country.

Transmission

The Update indicates PacifiCorp incorporated the Energy Gateway Transmission Expansion Project into its transmission topology in developing the Business Plan. However, whether Path C is modeled as a 300 MW upgrade to the existing line as it was in IRP 2007 or as a new line with a significantly larger capacity is unclear.

We are concerned by the lack of analysis. Transmission is both a substitute and a complement for generation, and it must be evaluated within the IRP rather than fixed outside the evaluation process. Transmission additions, like any other resource, must be selected and cost-justified as

---

[5] L. Agapay and R. Gunn. 2008. "Greater Impacts at Reasonable Costs – Setting and Meeting Energy Efficiency Resource Standards with Best Practices." *Proceedings of the 2008 ACEEE Summer Study on Energy Efficiency in Buildings.* Washington, DC: American Council for an Energy-Efficient Economy.

[6] H. Geller and J. Schlegel. 2008. "Update on Utility Energy Efficiency Programs in the Southwest." *Proceedings of the 2008 ACEEE Summer Study on Energy Efficiency in Buildings.* Washington, DC: American Council for an Energy-Efficient Economy.

[7] *2009/2010 Demand-Side Management Biennial Plan – Electric and Natural Gas.* Public Service Company of Colorado (Xcel Energy). Aug. 2008.

[8] *2008-2012 Action Plan.* Conservation Resources Division, Seattle City Light. Aug. 26, 2008.

[9] Presentation of Margie Harris, Energy Trust of Oregon, at the 2008 ACEEE Summer Study on Energy Efficiency in Buildings, Pacific Grove, CA, Aug. 2008.

part of an overall portfolio. Not to do so violates the IRP guideline that requires the consideration of all resources on a consistent and comparable basis and could result in a suboptimal portfolio selection. In its May 2003 Order on IRP 2003, the Commission made clear that this guideline applies to transmission. It directs the Company to address transmission on an equal basis with other resources.[10]

We urge the Commission to direct the Company to evaluate all transmission projects within the context of the IRP so that the benefit to customers can be demonstrated.

Action Plan

Item 7 of the Action Plan addresses PacifiCorp's decision to issue an All-Source RFP to meet its resource needs over the 2012 to 2016 timeframe. As a result PacifiCorp removed items 8-12 that specified the type, timing and location of resources.[11] The effect of this decision is to move to the RFP evaluation the determination of the optimal type, timing and resource location. If continued in future IRPs, this could result in the IRP planning process becoming more of an evaluation of need than an analysis of optimal resource acquisition strategies or the determination of the portfolio that best balances expected cost, risk and uncertainty.

Because the RFP appears to have replaced the IRP in determining the optimal, type, timing and resource location, the RFP process must be conducted in compliance with the 1992 Order promulgating IRP Standards and Guidelines. The requirement that resources be evaluated on a consistent and comparable basis is particularly apropos. We look forward to participating in the modeling workgroup that PacifiCorp will convene in docket 07-035-94.

II. MODELING ASSUMPTIONS RELATING TO COAL ACQUISITIONS AND IMPLICATIONS FOR IRP AND RFP PROCESSES

In its Update, PacifiCorp constrained pulverized coal and IGCC as options through 2017, the time horizon for the ten-year Business Plan. The Commission, however, required PacifiCorp to allow coal-based bids in response to its All-Source RFP. Accordingly, we wish to address several critical inputs PacifiCorp incorporates into its modeling of coal resources.

We note that PacifiCorp increased the projected capital costs of new coal-fired facilities by 49%, to approximately $3000/kW installed. We support this proposed adjustment and further note that, given recent extraordinary volatility in the steel and other commodity markets, the revised value is likely to be too low. If PacifiCorp receives coal-fired bids in response to its All-Source RFP, the Company – and the Commission – should very carefully assess any capital cost escalators embedded in the price structure as to minimize associated risks to ratepayers.

More importantly, we are quite concerned about PacifiCorp's projection of operating costs relevant to coal-fired facilities, particularly coal prices and CO2 emission allowance values.

---

[10] The Utah Commission explicitly ordered the Company to address transmission on an equal basis with other resources in its May 2003 order on IRP 2003. Report and Order, Docket No. 03-2035-01. P. 13.

[11] IRP 2007 Update, pp. 22-23.

Coal Prices

In our initial comments to the 2007 IRP filing, we raised the fact that PacifiCorp's coal prices increased significantly from 2003 to 2006. Since that filing one year ago, the domestic and international coal markets have actually increased dramatically in price and price volatility. Eastern coals are up roughly 200% over year-ago levels.[12] While constraints in transportation and electric transmission capacity continue to isolate the Powder River Basin (PRB) from the broader continental market, we believe the price disparity between regional production areas will induce greater use of PRB in place of eastern coals, and cause significant price shifts in PRB coal, in the not-too-distant future.

Although PRB coal is currently low-priced relative to eastern coals, its price has been quite volatile in the recent past. In fact, a recent analysis of Colorado coal and two types of PRB coal (8,400 and 8,800 Btu/pound), provided by Public Service of Colorado, shows that western coal experienced more price volatility than natural gas at Henry Hub over the period June, 2002 to September, 2007.[13] The results of the analysis are presented in the following table:

Table 1. Comparison of Commodity Volatility

Commodity	***Gas @ HH***	***PRB 8400***	***PRB 8800***	***Colorado Coal***
Volatility Index	32%	43%	43%	33%

As seen in the natural gas market, price volatility leads to shorter-duration contracts and financial hedging mechanisms. The coal markets are moving in this direction. In fact, PSCo recently indicated that only 29% of its required coal commodity and 33% of its required transport services for 2010 was currently under contract. Shorter contract durations represent a quickly evolving market. Suppliers do not want to be obligated to provide coal or transport services at current rates plus a reasonable escalation factor because the market fundamentals that set prices are moving so quickly – to do so would greatly limit profit opportunities. That strongly indicates suppliers expect prices to be volatile, and most importantly, to escalate faster than the rate of inflation.[14]

Exacerbating the overall volatility in the domestic and international coal markets, coal mining throughout the country will be subject to an increasing cost structure. According to a recent survey of coal resources on Federal lands, most PRB coal has an overburden thickness from 450

---

[12] Northern and Central Appalachian coals are currently trading at $140 - $150/ton, roughly three times the $45 level of September, 2007. See EPA price data at: http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html

[13] The volatility measure is calculated as the standard deviation, or statistical spread, of the prices divided by the average of the prices.

[14] In another sign of volatility in the coal markets and the markets' need to hedge against such volatility, Intercontinental Exchange Inc., one of the largest energy futures trading platforms, recently announced the development of two coal futures contracts at its European trading division.

– 2,000 ft, and is not “surface accessible.” [15] Underground mining, and even deeper surface mining, will lead to far more costly coal coming out of the PRB in the not-too-distant future.

Due to these considerations, and the possibility of receiving coal-based bids via its All-Source RFP, we strongly advocate for a more thorough examination of the coal markets and the impact on future prices and price volatility that could be experienced by PacifiCorp customers if coal-based resources are selected. We also note that PacifiCorp’s stochastic analysis of various portfolios makes no consideration of potential coal-price volatility. Given that the coal markets are, in fact, quite volatile and subject to a wide array of national and international market forces, we believe it is critical to incorporate coal price volatility in any stochastic risk assessment that may be conducted following the receipt of bids pursuant to the RFP processes.

CO2 Forecast

There are two primary problems with PacifiCorp’s CO2 forecast used for the Business Plan portfolio modeling. The first problem is the starting price of $8.62 / ton in 2012. This starting price value is well below *both* forecasts of prices associated with CO2 cap and trade programs *and* actual trading ranges for CO2 in current carbon-constrained economies. The Lieberman / Warner bill was the most recent and well-reviewed federal legislation effort to constrain greenhouse gas emissions in order to negate the impacts of climate change. An array of analyses was conducted to assess the likely price of CO2 allowances coming from that legislation. These analyses show a wide range of 2010 CO2 emission prices, roughly between $10 - $30/ ton of CO2.[16] Xcel Energy recently incorporated reference prices of $20/ton starting in 2010 into its IRP planning analysis.

Importantly, actual prices for emission allowances currently trading on CO2 markets are well above the PacifiCorp starting reference point as well. The most viable trading market is associated with the European Union (EU) carbon market, which is currently trading at roughly $29/ton (23 Euros / metric ton).[17] Given even modest escalation rates, EU prices are likely to be roughly four times higher than PacifiCorp’s starting price in 2012. The EU market prices represent the best data available on CO2 allowance values, and should be relied on to inform any projection of U.S. emission allowance values.

The second problem with PacifiCorp’s CO2 price forecast is that the escalation rate is far too low. PacifiCorp’s price escalation is at odds with most major forecasts of CO2 prices. Public Service Colorado recently proposed in its IRP a 7% annual escalation rate for CO2 prices based

[15] *Inventory of Assessed Federal Coal Resources and Restrictions to Their Development*, prepared by the U.S. Departments of Energy, Interior and Agriculture, August 2007

[16] At the low end of the range, see the Clean Air Task Force report at: http://lieberman.senate.gov/documents/catflwcsa.pdf . At the high end of the range, see the American Conference of Capital Formation and National Ass. Of Manufacturers report at: http://www.accf.org/PPT/ACCF-NAM.ppt#361,9,Macroeconomic Impact of Lieberman-Warner Bill: Carbon Allowance Price (2007$/Ton CO2)

[17] See, for example, http://www.pointcarbon.com/

on analysis of the Lieberman-Warner bill. The Clean Air Task Force's recent projection of CO2 allowance values in association with the Lieberman-Warner bill is over 7.8%.[18]

The low escalation rate appears to be due to a primary assumption in PacifiCorp's model - that CO2 emissions decline after 2011.[19] The basis for this assumption is not specified, and more importantly, inexplicable given that almost every utility in the country (including PacifiCorp) is adding or planning to add fossil-fueled assets to meet load growth. We believe this assumption, if we comprehend the IRP Update accurately, leads to significant under-estimation of CO2 emission allowance values. PacifiCorp should be required to rerun its model excluding this unrealistic assumption, and revise its CO2 price forecast accordingly.

We also note that PacifiCorp evaluated CO2 allowance costs under an assumed "Cap and Trade" scenario whereby it will receive allowances equal to the emissions in a baseline year at no charge. Under this scenario, as we understand PacifiCorp's methodology, the Company is assuming a CO2 emissions costs only for incremental emissions above the baseline year. Due to this modeling technique, PacifiCorp found only minimal differences in total cost under the array of CO2 price scenarios applied. We are concerned that this approach ignores the opportunity value of reducing emissions below baseline levels. That is, by reducing CO2 emissions below the baseline level, PacifiCorp may be able to redeem excess allowances and apply the revenues to customer bill discounts. Further, the allocation of free allowances to historical emitters in a national Cap and Trade system will likely decline over time in order to induce actual emission reductions. At this juncture, it is not clear what allowance allocation trend PacifiCorp assumed it would receive over time.

Finally, as described in our initial comments, by averaging very low CO2 price curves with more reasonable versions, and applying PacifiCorp's discount rate, the differences in the CO2 prices curves are diluted.

III. DISCOUNT RATES

As mentioned in our original comments, we believe PacifiCorp's discount rate of 8.5% is inappropriately high given the broad societal and long-term impacts of the decisions made through this IRP process. Importantly, the Company's discount rate only accurately reflects the cost of *capital* expenditures. Operating expenditures are generally not financed as capital (via debt and equity). Instead they are financed through cash, via short-term (*i.e.*, low-cost) financial instruments such as working capital bank notes, or a combination of cash and financial instruments.

We recognize that, generally, financial analyses do not apply two separate discount rates to different cost streams. Importantly, present value analyses primarily evaluate cash flows, not

[18] See http://lieberman.senate.gov/documents/catflwcsa.pdf. Prices increase from $10/ton in 2010 to $45/ton in 2030. Those values incorporate a 7.82% annual escalation rate.

[19] If both quantity and prices were input assumptions – as indicated in the IRP Update at 4 – then, it is unclear at this juncture what exactly the model output was.

streams of expenses. Hence the nomenclature: discounted cash flow (DCF) analysis. However, cash flows are irrelevant to projects that fulfill regulated obligations; electric utility resource selection is based upon lowest total *costs* to the customer.

Simply put, the Company's Weighted Average Cost of Capital, or WACC, is an inappropriate mechanism by which to evaluate operating costs across resources. Relying on WACC to discount operating costs could lead to the selection of resources with high fuel / CO2 allowance costs such as coal or gas-fired units. In contrast, relying on WACC to discount operating costs under-estimates the benefits of renewable & DSM resources. These resources have no fuel costs and require no CO2 allowances, negating the majority of operating costs usually relevant to electric generating technologies. However, by discounting all operating costs at the Company's WACC, the importance of these expenditures (or cost savings) in the future is inverted. Given the very long lives of the assets likely to be under consideration via the RFP process, we strongly encourage the Utah commission to require PacifiCorp to evaluate and select resources for approval with minimal discounting of operating costs – perhaps in the 3% to 5% range. At a minimum, PacifiCorp should be required to evaluate the projects under alternative discount rates, particularly for costs that are not capitalized by the Company.

IV. ALL-SOURCE RFP

PacifiCorp developed separate RFP categories for renewable energy and all other generation. The All-Source RFP precludes renewable energy resources that are not fully dispatchable or capable of providing firm capacity. We believe this approach is inappropriate for a variety of reasons. First, all renewable energy resources provide some capacity, and should be appropriately acknowledged for the capacity credit they provide.[20] Second, several renewable energy resources are counter-balancing, and perform very well when considered in combination. Wind and concentrating solar resources, for example, can balance one another seasonally and, even, on a daily basis. Third, and most importantly, given the extraordinary circumstances and challenges represented by climate change, PacifiCorp – indeed, all utilities – must find evolutionary ways to mitigate CO2 emissions. This includes combining and supporting non-emitting and low-emitting resources in unique portfolio arrangements to fulfill all goals of utility resource planning.

We recognize that, at this juncture, the All-Source RFP has been approved and is ready for issuance. Accordingly, we advocate that PacifiCorp evaluate the ability of bids received in response to the Renewable RFP to meet a significant portion of the obligations segregated for the All-Source RFP. PacifiCorp should also make known this possible outcome to bidders to the Renewable RFP so that they may adjust their bids accordingly. Only then, can PacifiCorp reasonably comply with the Commission's requirement to consider "all resources on a consistent and comparable basis" and to select "the optimal set of resources given the expected combination of costs, risk and uncertainty" as described above.

[20] Capacity credit is unique from capacity factor. Capacity credit represents the ability of a resource to produce during a set of peak hours throughout the year. Capacity factor represents the ability of a resource to produce during all hours of the year.

Admittedly, certain renewable resources such as wind energy provide lower capacity and should be weighted accordingly. However, other renewable energy resources can provide significant capacity benefits. For example, Xcel Energy credits facilities utilizing concentrating solar power (CSP) with storage technologies a capacity credit of 68%. That is, Xcel recognizes that CSP with storage provides 68% of its nameplate capacity during the critical peak hours of the year.

Given the extensive solar resource base in Utah and PacifiCorp's summer peak load profile, CSP with storage facilities represent an extraordinary opportunity to fulfill energy *and* capacity obligations with no incremental risk associated with the price or availability of fossil fuels or CO2 emission allowances. Similarly, although geothermal facilities may not be fully dispatchable, the incorporation of these baseload resources into a broader portfolio may reduce PacifiCorp's overall cost and risk profile. With respect to wind resources, if given the appropriate incentive, wind energy developers may be able to integrate their projects with storage or backup facilities so as to provide significant capacity benefits – via physical or financial/contractual arrangements – to PacifiCorp and its customers.

In fact, no technology or project can provide capacity benefits equal to 100% of its nameplate rating. Indeed, all resources have equivalent forced outage rates above 0%. Prematurely excluding renewable energy resources, based on the assumption that they provide no capacity benefits (and that fossil resources are wholly reliable during peak periods) is simply inappropriate and will lead to sub-optimal resource selection.

Based on the potential cost and risk benefits of renewable energy resources, we urge the Commission to require PacifiCorp to assess the possibility of resource portfolios, not yet contemplated, that incorporate far more renewable energy from bids received in response to the Renewable RFP.[21] As well, PacifiCorp should also examine the benefits and costs of significantly higher DSM investments that currently contemplated. We note that to exclude these options would negate compliance with the Commission's IRP guidelines, and place customers at risk of suboptimal resource selection and decades of potentially unnecessary fossil fuel and CO2 allowance procurement.

[21] Of the eleven alternative resource portfolios evaluated in 2007 IRP, the two lowest cost portfolios included additional wind resources (RA3 and RA7).

Respectfully submitted,

WESTERN RESOURCE ADVOCATES

____
Michael Mendelsohn, Senior Policy Advisor
Nancy Kelly, Senior Policy Advisor
2260 Baseline Rd., Suite 200
Boulder, CO 80302
303-444-1188
mmendelsohn@westernresources.org
nkelly@westernresources.org

UTAH CLEAN ENERGY
Sarah Wright, Executive Director
1014 2nd Avenue
Salt Lake City, UT 84103
801-363-4046
sarah@utahcleancnergy.org

SOUTHWEST ENERGY EFFICIENCY PROJECT
Howard Geller, Executive Director
2260 Baseline Rd., Suite 212
Boulder, CO 80302
303-447-0078
hgeller@swenergy.org

September 9, 2008