BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Acknowledgment of	)	
PACIFICORP's Integrated Resource	)	DOCKET NO. 05-2035-01
Plan 2004	)	
	)	

COMMENTS OF WESTERN RESOURCE ADVOCATES AND UTAH CLEAN ENERGY

Western Resource Advocates (WRA) and Utah Clean Energy (UCE) request that the Commission accept the following comments on PacifiCorp's 2004 Integrated Resource Plan (2004 IRP):

Summary of Comments

WRA and UCE commend PacifiCorp for several significant improvements in evaluation methodologies in its 2004 Integrated Resource Plan (2004 IRP). The 2004 IRP includes a monetization of wind's capacity contribution towards planning reserve margins and a more thorough evaluation of integrated gasification combined cycle (IGCC) technology options. It also better integrates the stochastic risk analysis and scenario risks analyse particularly as it relates to the cost/risk tradeoffs between IGCC and pulverized coal. In addition, the 2004 IRP makes greater use of automatic resource addition logic to inform the portfolio evaluation process.

While WRA and UCE agree with much of the IRP, we do not believe that it is possible at this time to conclude that Portfolio E is the preferred portfolio for the PacifiCorp system. Portfolio E would include substantial new investments in conventional fossil-fuel resource options on the East Side of its system during the 10-year planning period, including two combined-cycle gas units in fiscal years 2010 and 2014 totaling 1,085 MW and two pulverized coal units in fiscal years 2012 and 2015 totaling 958 MW. The IRP action plan proposes to procure two of those resources, a 550 MW gas resource in FY 2010 and a 600 MW coal resource in FY 2012, as part of this IRP cycle. Before committing to supply-side investments of this magnitude and expense, we believe that it is essential that the Company revisit certain key cost assumptions and portfolio options. The Company should: (1) consider additional wind resources as resource alternatives in the latter years of the planning period, including under the Portfolio Q transmission expansion scenario; (2) continue to improve its IGCC cost assumptions and technology analysis for consideration of IGCC as the Company's next baseload unit; and (3) develop a long-term strategy for managing and reducing financial risks to Company shareholders and ratepayers of future environmental regulatory requirements, including the regulation of carbon dioxide emissions from the electric utility sector.

I. Evaluation of Wind Resources

A. Wind as a Resource Option

The Company's 2004 IRP confirms that wind resources represent a cost-effective addition to the Company's resource portfolio. It can help reduce the fuel price and environmental regulatory risks of conventional resource options and the environmental impacts of electricity generation. The 2004 IRP reaffirms the Company's commitment to acquire the 1,400 MW of wind resources identified in the 2003 IRP. The results of the capacity expansion model (CEM) analysis confirms the cost-effectiveness of wind at this level.

WRA and UCE understands the Company's decision to follow through on its existing wind commitments from the 2003 IRP prior to committing to acquire additional wind as part of the 2004 IRP. But we do recommend that the Company include wind as a resource available to the model particularly in the latter years of the planning cycle, as was done in the CEM side bar study, even if the Company does not propose to acquire these incremental wind resources in the 2004 IRP action plan beyond the 1,400 MW. The Company is proposing as part of this action plan to acquire substantial new fossil resources in the 2009-2012 timeframe and has set forth steps in its action plan to complete those acquisitions. In addition, the Company's preferred portfolio identifies significant increases in conventional resources in the latter years of the planning horizon, including a new coal-fired unit in Wyoming in 2015 at the Jim Bridger station. The availability of additional cost-effective wind resources beyond the 1,400 MW could provide substantial benefits to ratepayers and help reduce the environmental impacts of the Company's generation fleet. If the IRP model identifies additional wind beyond the 1,400 MW as cost-effective, it would affect the timing, size, cost-effectiveness and relative risk rankings of the different fossil resource options in the preferred portfolio.

The CEM sidebar study suggests that renewable resources beyond the 1,400 MW would be an economical and environmentally beneficial addition to the Company's resource fleet over the intermediate and long-term. Figure J.1 (Appendix J, p.145) graphs the ratio of costs of the wind bids received in response to the Renewables RFP 2003-B to the forward price curve. The Company received more than 6,000 MW of resources in response to the RFP 2003-B, of which 85% were from wind resources. The chart indicates that approximately 1,400 MW of those bids were at or below the Company's forward price projections, that an additional 900 MW of renewables was priced at only 10% above the Company's projections, and that an additional 800 MW on top of that was available at a price of 20% above the Company's forward price projections.

We believe that the price stability and emissions reduction benefits of renewable energy more than justify the acquisition of renewable resources within such a narrow band of the Company's forward price projections. Unlike gas-fired and coal-fired resources, the Company has a high degree of certainty as to the long-term costs of renewable energy resources at the time of contracting for the resource and can lock in fixed prices for decades. Renewable resources are largely immune from the tremendous fuel price volatility that has plagued gas-fired generation and, to a lesser extent, coal costs. Further, renewable resources are not subject to the risk of future environmental regulatory requirements including future climate change regulations, which could dramatically affect the long-term economics of coal-fired generation in particular.

Another often overlooked price stability benefit of wind resources is the high degree of certainty as to capital costs, particularly relative to new coal-fired power plants. Both wind turbines and coal-fired power plants are capital intensive resources that are sensitive to, among other factors, steel prices and interest rates. Yet, the substantial differences in lead-times between these two resources types dramatically affect the level of uncertainty faced by ratepayers as to the risk of increased capital costs. If transmission is available, wind resources can often be installed and operating within less than a year of contracting for the resources, whereas coal-fired generation often takes four years or more to develop. For wind projects, the capital costs and therefore the cost of energy for the project are essentially fixed at the time of contracting and will remain stable for the life of the contract. In contrast, the long construction lead-time for coal plants means that capital costs could still increase -- often dramatically -- between the time the decision is made to develop the resource and the time it comes into service.[1]

B. Capacity Credit for Wind

WRA and UCE support PacifiCorp's recognition of the contribution of wind towards meeting system planning reserves in the form of a capacity credit for wind. We believe that PacifiCorp's has adopted an appropriate statistical methodology for calculating wind's capacity credit. PacifiCorp based its 20% estimate on its 2004 Integrated Resource Plan (2004 IRP), Appendix J at pages 140-144. The Company's 2004 IRP methodology represents a significant improvement over the Company's treatment of wind capacity credit in the January 2003 IRP. However, we remain concerned that the methodology may still underestimate the capacity contribution of wind. The Company's approach appears to focus too narrowly on a single month of July for purposes of determining the reduction in energy not served (ENS) by adding wind to the system. While we understand the importance of ensuring adequate resources to meet the summer peak, it is also important to recognize that wind does contribute towards meeting planning reserves during the remaining months of the year, including during the Company's winter peak and the shoulder months when the Company may have conventional facilities off-line for planned or unplanned outages. A properly designed statistical methodology for calculating wind's capacity contribution during all months of the year will necessarily place greater weight on the summer peaking months, as it

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[1] For example, when first presented to the Arizona Corporation Commission for approval in 2001, the proposed two unit expansion of the Springerville Generating Station in Northeast Arizona was projected to have capital costs in the range of $1,500 to $1,800 per kW of installed capacity. The current publicly available capital cost estimates for the first unit to be added at Springerville (referred to as Springerville Unit 3) are approximately $2,348 per kW of installed capacity, representing a 30-55% increase in capital costs over initial projections. *See* Tri-State Generation & Transmission Association's 2003 Annual Report.

should, but it will also place appropriate weight on wind's capacity contribution during the remaining months of the year.

C. Wind Integration Studies

Even though the Company is not proposing to acquire additional wind beyond its 2003 IRP commitments as part of this 2004 IRP, WRA and UCE believe it is vitally important that the Company take proactive steps now to identify and address uncertainties associated with wind at penetration levels up to and beyond the currently proposed 1,400 MW. During the IRP public input meetings, concerns have been raised by PacifiCorp representatives and others about the transmission impacts of wind at higher penetration levels, especially on the East side of the system. In response to comments on the draft IRP, PacifiCorp also acknowledges that as wind is added to the system these issues will require more in-depth analysis (Appendix L, p.174). As the wind integration studies performed by PacifiCorp and others suggest, the uncertainty associated with integrating wind onto the transmission system at higher penetration levels appears manageable. This is especially the case when compared to the alternatives of predicting future natural gas prices or environmental compliance costs related to coal-fired generation. Nonetheless, we recommend that the Company and regulators take steps now to begin addressing the issue of integrating large quantities of wind onto the PacifiCorp system. WRA recommends that, as part of its 2004 IRP action plan, the Company should commit to: (i) perform a revised integration cost analysis on its system using the results of the 2003-B Wind RFP, and (ii) a revised ELCC analysis using the results of the 2003-B Wind RFP that looks at wind's capacity contribution in all hours of the year. WRA requests that the Company solicit public input on the scope and methodology of the studies and establish a timeline for completion so as to inform the next IRP cycle.

D. Renewable Energy RFP 2003-B

WRA and UCE are troubled by the slow rate of progress in finalizing contracts resulting from the Renewables RFP 2003-B. Since the 2003 IRP was released, the Company has contracted for two new gas-fired power plants totaling 1,059 MW. In response to RFP 2003-B in February 2004, the Company received over 6,000 MW of renewable resource bids for dozens of proposed projects but has not yet announced any contracts for renewable resources. We recognize the uncertainty and unsettling market conditions that have resulted from erratic Federal policy on the wind production tax credit and the resulting turbine shortages, but we still question why no projects have proceeded beyond the short-listed stage nearly fourteen months after the RFP was issued.

II. Evaluation of IGCC

WRA and UCE recommend that, if the Company is going to pursue additional coal-fired generation, it should employ IGCC technology. We have shared the Company's IGCC analysis with technical experts from the Clean Air Task Force and have identified several recommendations for improvement and further refinement, as discussed below. But before investing in expensive new baseload facilities of any type, it is imperative that the Company redouble its efforts to acquire all cost-competitive renewable energy, energy efficiency and combined heat and power (CHP) resources to minimize the costs and risks to ratepayers and the environmental impacts of the Company's resource fleet.

When comparing IGCC technology to pulverized coal, it is important that the Company, stakeholders and regulators view the issue from a system-wide perspective over the long-term and not solely in terms of meeting incremental resource needs. While the costs of a large baseload coal unit are substantial, the Company's existing resource fleet is already heavily dependent on pulverized coal technology, potentially placing enormous risks on ratepayers of future environmental compliance costs from the existing coal fleet. The choice of IGCC technology would not only preserve the option value of carbon sequestration for that individual coal unit, it would also help the Company develop the knowledge, institutional capacity and expertise with coal gasification technologies that could be applied to the repowering of the Company's existing coal fleet over time so as to mitigate some of these existing risks. The choice of IGCC technology may also help reduce the permitting risks associated with the development of a new baseload coal unit. It may also increase the prospects of approval from the multiple jurisdictions in which PacifiCorp operates.

A. Carbon Capture and Storage

One of IGCC's main advantages relative to pulverized coal is its ability to easily capture and isolate carbon dioxide emission from the facility. Carbon dioxide ($CO_{2)}$ is the principal greenhouse gas linked to human-induced global warming. Unlike a pulverized coal unit, an IGCC plant could be retrofitted relatively easily for carbon capture and sequestration in the future.[2] IGCC technology uses a coal gasifier to convert coal into a synthetic gas stream, or "syngas." The syngas is then run through a combined cycle combustion turbine to produce electricity. In an ordinary IGCC plant, the main carbon compound in the syngas is carbon monoxide (CO). For carbon capture, the CO is converted to CO_2 with a water shift reaction. This creates more H_2 and CO_2 in the syngas. Several options exist for removing the CO_2 in the syngas. In one common option, the same equipment used to remove hydrogen sulphide (H_2S) from the syngas is also used to remove CO_2. This technology is commercially available and widely used in gasification processes used to make ammonia fertilizer. The isolation of CO_2 from the syngas is a relatively inexpensive process in an IGCC plant because the CO_2 is in a concentrated gas stream. In contrast, the cost of removing CO_2 from a conventional coal plant is expensive because the CO_2 emissions in the flue gas are dilute, and the technology for capturing the CO_2 is not commercially available.

[2] While IGCC may be face reduced risk of expensive environmental retrofits relative to pulverized coal, it bears repeating that renewable energy and energy efficiency resources avoid this risk almost completely. CHP applications also pose significantly reduced CO_2 risk due to the combined efficiency of the industrial processes.

The ability to respond to a carbon constrained regulatory environment is an important reason for the wave of new IGCC proposals that are occurring in the Midwest. Four gasification projects are proposed in Illinois, two are being evaluated in Indiana, one in Minnesota, and AEP is seeking regulatory approval for two plants totaling over 1,000 MW to be located in Kentucky, Ohio, or West Virginia. In its filing for cost recovery for an IGCC plant in Ohio, AEP noted that, "the incremental cost difference in the levelized cost of electricity between IGCC and other technologies is relatively small. However, the savings with IGCC in the event of retrofitting for future carbon capture regulations are significant…"[3]

B. IGCC Modeling Analysis

The Company's evaluation of IGCC technology in the 2004 IRP is much improved over its analysis in the 2003 IRP. The Company has seriously considered IGCC technology options and project configurations from well-established vendors. Further, the Company's has developed a sound analytic framework for assessing the trade-offs between increased capital costs and environmental compliance risk between IGCC and pulverized coal (Figure 6.1, p.91), which can help inform the ultimate decision on choice of technology.

The Company had initially included an IGCC unit in its base case portfolio (Portfolio A) in 2015, but ultimately elected to replace that IGCC unit with pulverized coal in its preferred Portfolio E. The Company identified two principal factors affecting the higher costs of IGCC relative to pulverized coal: the higher capital costs and the reduced availability. For purposes of the 2004 IRP analysis, the Company assumed the "H" configuration without a spare gasifier, which the Company estimates would have unit availability of only 75% (p.90). The Company also notes, however, that recent developments in IGCC technology indicate that the 7FB design using a 3x2x1 configuration (3 gasifiers, 2 gas turbines, 1 steam turbine) can be expected to have improved availability levels of 90%, but that this updated information was not available in time for the IRP modeling runs (p.90). The Company did perform a stress case run on its preferred portfolio by substituting an IGCC using the 7FB design for the pulverized coal unit in 2012 but ultimately concluded it was not yet cost effective.

WRA and UCE appreciate PacifiCorp's efforts to continually update its analysis of IGCC. The improved availability of the 7FB design relative to the H configuration could help reduce the Company's exposure to the market and gas price fluctuations. We agree with PacifiCorp that the 7FB design merits further consideration. This analysis should take place before proceeding with any new pulverized coal units.

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[3] Public Utilities Commission of Ohio, Case 05-376-EL-UNC, Application received by Columbus Southern Power Company and Ohio Power Company, dated March 18, 2005

C. IGCC Cost Estimates

Figure 6.1 (p.91) identifies the CO_2 emissions allowance price at which the improved heat rate and CO_2 sequestration costs of IGCC would outweigh the increased all-in costs relative to pulverized coal. A revised cost analysis would likely show that conventional coal and IGCC costs are closer than the Company's analysis indicates and the "break-even" CO_2 allowance cost is lower than the reported $33 per ton of CO_2 identified in Figure 6.1.

We are concerned that the Company's estimate of the all-in cost differential between IGCC and pulverized coal overstates the likely cost gap by a factor of two. In Figure 6.1, PacifiCorp estimates the differential in all-in costs of electricity (without carbon dioxide capture and sequestration) between a conventional coal plant and an IGCC plant to be around $9 per MWh. Included in this estimate is the Company's estimated capital cost of $2,350 kW for the "Updated Assumption-7FB" turbine configuration, which is approximately 35% higher than its capital cost estimates for a supercritical pulverized coal plant. This capital cost differential appears to be overstated. General Electric (GE) estimates that the gap today is closer to 20% for its IGCC technology. GE has also stated that, once its reference plant design is complete in the next 12 months, it expects the gap between IGCC and pulverized coal will be no greater than 10%. Over the last decade, the capital costs of IGCC plants have fallen 40%.[4] Based on current cost trends, if Hunter 4 is expanded in 2012, as is contemplated by Portfolio E, the capital cost difference between conventional coal and IGCC may disappear entirely.

IGCC plants have low variable costs. Based on studies from Illinois, PacifiCorp's estimate of $1.80/MWh could be overstated by between 80¢ to $1 per MWh.[5]

D. IGCC Deployment in the Interior West

Western utilities do face additional challenges in deploying IGCC technology relative to their Midwestern counterparts, but these issues can be addressed. Both coal type and altitude influence IGCC capital costs. Lower rank coals increase IGCC costs due to the fuel's lower heat content. The higher altitude also increases costs due to the need for a additional gasifier capacity to account for reduced oxygen levels in the atmosphere.

Capital costs for IGCC can be reduced by using higher heating content coals or coal blends. In addition to examining subbituminous coals, the Company should evaluate bituminous coals (such as those mined in Utah) and a blend of PRB coal/petcoke. Both of these options would reduce capital costs significantly by improving the heating value

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[4] Coal Gasification- Today's Technology of Choice and Tomorrow's Bright Promise, David Denton, AIChE- East TN Section, October 29, 2003.

[5] TEC IGCC Feasibility Analysis, The ERORA Group, Agreement No. 04-15 Southern Illinois University, January 2005.

of the fuel. For example, a blend of PRB coal/petcoke would lower capital costs relative to a subbituminous-only option without any increase in variable O&M or fixed O&M of an IGCC.[6] The change could reduce fuel costs between $.15 and $.3/mmBtu. This fuel savings could reduce the price of electricity from an IGCC by as much as $2/MWh.

PacifiCorp should also evaluate the Siemens Westinghouse turbines in addition to the GE turbines examined in the IRP. Siemens Westinghouse is partnering with ConocoPhillips to market this technology. Siemens recently announced that their turbines would be used in a proposed Illinois IGCC plant.[7] The 501F turbine is about 18% larger than the GE 7FA turbine, and may offer cost advantages at altitude due to the larger capacity relative to the GE design. Furthermore, Siemens hopes to offer a next generation turbine prior to 2012 that would reduce NOx levels to around 2-3 ppm.[8] Finally, membrane technology is under development that would eliminate the Air Separation Unit in an IGCC plant and reduce oxygen costs by one-third.[9] This technology could be available for the 2012 start-up contemplated in the IRP.

The IRP should evaluate co-production opportunities at an IGCC site as a means for bringing down costs to ratepayers. Co-production can make an IGCC plant more economically attractive by adding revenue and better utilizing equipment for industrial applications in addition to electricity generation. During times of low-electricity prices, the plant can be used to produce methanol, naphtha, ammonia, F-T diesel, methane or other chemicals. In addition, if the 3x2x1 design is selected, the extra gasifier can be used to make chemicals or other processes when it is not needed for electricity production. Through co-production, the incremental cost impacts to ratepayers of the spare gasifier can be reduced by utilizing it for other applications while still maintaining the benefits of the improved unit availability for electricity generation. Co-production may also potentially reduce overall carbon emission levels the extent that the combined efficiency of the industrial operations exceeds that of stand-alone facilities.[10]

A study paid for by the State of Illinois and conducted by ERORA Group, a company proposing an IGCC in Illinois, illustrates the impacts of co-production at an IGCC facility on overall electricity costs. Prior to selecting IGCC as the technology for their site, they evaluated both conventional coal and IGCC with methanol co-production.

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[6] Using 7FA turbines, ConocoPhillips estimates 100% PRB coal heat rate of 9600 Kwh/Btu. With 20% petcoke and 80% PRB, heat rates fall to 9100 Kwh/Btu. Capital costs of the 20% petcoke and 80% PRB would be lower than a 100% PRB configuration, and would rival a 100% bituminous configuration.

[7] Announced at Electric Power Conference, Chicago Illinois, April 5, 2005.

[8] Improving IGCC Flexibility Through Gas Turbine Enhancements, H. Morehead, et al, presented at Gasification Technologies 2004 Conference, Washington DC, October 5, 2004.

[9] ITM Oxygen for Gasification, Philip Armstrong, et al, Air Products and Chemicals, Gasification Technologies 2004, Washington DC, October 5, 2004.

[10] While WRA and UCE generally approve of the concept of co-production as potentially providing efficiency gains similar to those of CHP operations, it is still necessary to examine the full environmental implications of any such arrangement on a case-by-case basis, including consideration of air emissions, hazardous air pollutants, solid wastes, land impacts, water use and water quality impacts and other factors.

The study found that using the spare gasifier for methanol allowed the plant to operate at a lower cost than the conventional coal alternative. Co-production allowed the power block to reach high availabilities through the spare gasifier, but the methanol production when the spare was not needed helped pay for its capital costs. The result was a projected constant $36 per MWh electricity price even at low capacity factor.

III. Evaluation of DSM and CHP

WRA and UCE generally support the Company's analytic methodologies for evaluating DSM resources. The Company's analysis shows that DSM is a viable resource option that provides cost savings for ratepayers by reducing and deferring the need for supply-side investments. The Company's current approach is to identify a preferred portfolio and then to run a DSM decrement analysis on that portfolio. We generally agree with this approach but, because the stochastic and scenario risk sensitivity analyses are performed on the supply side portfolios prior to running the DSM decrement analysis, it may not fully capture the potential value of DSM as a tool for mitigating fuel price and environmental regulatory risks to ratepayers.

WRA and UCE also support the more comprehensive treatment of combined heat and power (CHP) technology options as part of the 2004 IRP. As with DSM, CHP can provide significant cost savings to ratepayers and reduced environmental impacts relative to conventional supply-side resources through the more efficient utilization of fuel inputs, typically natural gas.[11] We do have some initial concerns about whether the methodology fully reflects the potential capacity and energy contributions of CHP. The Company has significantly discounted the capacity contributions of CHP applications because the dispatch of the units is often not within the Company's direct control. This is the same type of issue that the Company initially faced when deciding how to model DSM and intermittent wind as part of the 2003 IRP. It may be the case that CHP applications, while not completely under the Company's dispatch control, nonetheless may make important contributions towards meeting planning reserve requirements. It may be possible to model those capacity contributions either as decrements to load, as is done for DSM, or statistically as part of a loss of load probabilistic analysis, as is done for wind. We recommend more detailed consideration of the modeling of CHP options in future IRP discussions. The Company include as an element to its action plan a proactive strategy for identifying and acquiring CHP resources. This plan could include discussion of financial and regulatory incentives for the Company to pursue CHP.

IV. Transmission Options

WRA and UCE strongly object to the current modeling of the Rocky Mountain Area Transmission Study (RMATS) transmission expansion from Southwest Wyoming into the Wasatch Front as Portfolio Q. The current Portfolio Q calls for 958 MW of coal-

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[11] As with any resource option, the environmental acceptability of a particular CHP application must be evaluated on a project-specific basis, especially for the "jumbo" projects referenced in the IRP document.

fired generation at Jim Bridger but no additional wind resources. The Company's IRP modeling analysis shows that this scenario would impose substantial costs and risks on ratepayers and it should be rejected. Wyoming is blessed with some of the premiere wind resources in the world, whose potential for supplying clean energy is restricted only by available transmission. The RMATS process identified upwards of 1,150 MW of wind in Southern Wyoming that could be accessed by expanding transmission access from Miners through Jim Bridger to the Wasatch Front.[12] The full wind potential in the region is orders of magnitude higher than the RMATS estimates. WRA estimates the wind potential in Wyoming at 882,547 Gigawatt-hours per year.[13] However, none of this additional wind is reflected in Portfolio Q. The Company should reconstitute Portfolio Q to include substantial new wind resources for consideration in the next IRP cycle.

V. Evaluation of Climate Change Regulatory Risk

WRA and UCE support the Company's use of imputed CO_2 costs as a base case assumption in the IRP analysis and in the RFP bid evaluation. We regard the use of an $8 per ton CO_2 proxy costs as a base case assumption as the low end of the range of reasonable values. It should be revisited. By way of comparison, Idaho Power in its 2004 IRP uses a CO_2 proxy cost of $12.30 per ton of CO_2 as a base case assumption beginning in 2008.[14] Xcel Energy, as part of a comprehensive settlement agreement in its 2003 Least Cost Plan in Colorado, agreed to use a proxy cost value of $9 per ton of CO_2 beginning in 2010 and escalating at 2.5%.[15] The California PUC has adopted an escalating cost of $5 per ton CO_2 in the near term, $12.50 per ton CO_2 by 2008, and $17.50 per ton CO_2 by 2013.[16] Currently, CO_2 emissions credits are trading on the European Union Emissions Trading Scheme in the range of €14-17 per ton of CO_2.[17]

WRA and UCE also support the Company's modeling of risk sensitivities on potential CO_2 compliance costs as scenario risks of $0, $25 and $40 per ton of CO_2. We would like to see the Company refine certain CO_2 risk sensitivities to reflect escalating costs over time for possible inclusion in future IRP cycles. We also support the Company's methodology for identifying the "strike price" for CO_2 compliance costs at which IGCC surpasses pulverized coal as the preferred alternative.

WRA and UCE support the Company's revised analytic framework for evaluating future CO_2 cost scenarios. The Company has retained ICF Consulting to develop projections of electric market clearing prices, gas prices, and non-CO_2 emissions

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[12] Rocky Mountain Area Transmission Study, pp.2-16 to 2-17.
[13] Western Resource Advocates, *A Balanced Energy Plan for the Interior West*, p.19, Figure 2.2 (available at http://www.westernresourceadvocates.org).
[14] Idaho Power 2004 IRP, at p.61.
[15] Comprehensive Settlement Agreement, Colorado PUC Docket Nos. 04A-214E, 04A-215E and 04A-216E (consolidated), ¶ 18.
[16] California PUC Decision No. 05-04-024.
[17] *See* http://www.pointcarbon.com. One Euro is equivalent to approximately 1.3 U.S. dollars.

allowance costs under each of the CO_2 cost scenarios.[18] WRA, in its comments on the 2003 IRP, emphasized the need for better integration of consideration of stochastic and scenario risks. This more dynamic treatment of market responses to different CO_2 compliance costs represents an important step in that direction.

As part of this 2004 IRP planning cycle, the Company deferred the timing of when CO_2 regulatory costs are anticipated to take effect until 2010, and it phased in those costs over a two-year timeframe. We are deeply concerned by the recent Utah Public Service Commission proceedings concerning the issuance of a Certificate of Convenience and Necessity for the Lake Side Project, where some parties and the Commission appear to have attributed significance to this revised modeling assumption as evidence of reduced CO_2 risk faced by the Company since the 2003 IRP was completed.[19] While, strictly speaking, the deferral of CO_2 costs may have the effect of reducing the anticipated present valuate cost impacts to ratepayers, there are other, far more significant events that have unfolded since the Company released its 2003 IRP that point towards even greater risks to ratepayers of significant future CO_2 compliance costs. Notably, the scientific evidence of climate change continues to mount. The observed impacts of climate change provide startling evidence that the Earth's climate is changing sooner and more rapidly than many had anticipated. Sooner or later, national policy makers will catch up with this scientific reality. With the ratification of the Kyoto Protocol in January 2005, the United States will continue to face increased pressure from the international community to take on binding commitments to reduce greenhouse gas emissions.

VI. Allocation of Risk for Future Environmental Regulatory Costs

WRA and UCE appreciate the Company's discussion of its expectations for cost recovery of future CO_2 compliance costs as part of the IRP. The issues raised by the Company are timely and merit serious discussion among the Company, regulators and other stakeholders. As a general matter, we believe the Company should receive credit for the proactive steps it is taking now to manage and reduce climate-change related risks to ratepayers. The Company has significantly improved its analysis of less carbon-intensive resource options and it has begun to evaluate advanced fossil fuel resource options such as IGCC that preserve the option of capture and storage of CO_2 emissions. The Company has also established an effective IRP public participation process and developed a robust methodology for evaluating CO_2 risk for incremental resource additions.

Nonetheless, the Company's greenhouse gas emissions continue to grow. Currently, under the IRP modeling framework, the model is indifferent as between a resource choice that reduces overall CO_2 emissions and one that increases CO_2 emissions but offsets those emissions through the acquisition of hypothetical CO_2 emission offsets. As between these two resource types, resource alternatives that result in actual reductions

[18] The Company does not specifically list demand response as one of the variables considered by ICF consulting, although demand-side price elasticity may be embedded in the market clearing price analysis.
[19] Due to staffing constraints, WRA was not able to participate in the Lake Side hearings.

in CO_2 emissions create substantially less risk for ratepayers. The IRP tends to focus primarily on the costs and risks associated with incremental resource additions. This tends to obscure the fact that ratepayers are already significantly at risk of increasing CO_2 compliance costs as a result of the Company's current heavy dependence on pulverized coal technologies for the existing fleet. It is against the backdrop of these "sunk risks" of the existing resource mix that the consideration of costs and risks of any resource plan for meeting incremental resource needs should be evaluated.

Perhaps the most interesting observation on the Company's 2004 IRP modeling analysis is the counter-intuitive result that the Company's PVRR for several of the less carbon-intensive short-listed portfolios actually declines when moving from the $25 per ton to the $40 per ton of CO_2 risk scenario. The Company identifies as the reason that substantial emission credits are created by reducing existing coal operations and running new and existing gas plants more frequently.[20]

Thus, the prospect of carbon-constrained future presents the Company and its ratepayers with both a challenge and an opportunity. To the extent that the Company invests in carbon-intensive resource choices with few options for economically reducing CO_2 emissions in the future, it could exacerbate existing risks faced by the Company associated with its existing resource fleet. On the other hand, if the Company increases its investments in less carbon-intensive resource choices and actually begins reducing its overall CO_2 emissions, it could help manage and reduce existing risks on its system and potentially free up emission reduction credits from existing resources as a new source of revenues. A transition towards cleaner, less carbon-intensive resources would also help reduce the public health and environmental impacts of electricity generation in Utah and the Intermountain West.

[20] The realization of these "savings" by ratepayers, of course, is highly dependent upon the modeling assumptions that CO_2 allowances will be allocated according to historical emissions and that there will be a perfectly working CO_2 emissions trading market in the future into which these surplus credits can be sold. If either one of these assumptions proves optimistic, then ratepayers could face more substantial CO_2 compliance costs associated with the Company's existing coal fleet.

Respectfully Submitted,

John Nielsen
Eric C. Guidry
Western Resource Advocates
2260 Baseline Road, Suite 200
Boulder, CO 80302
(303) 444-1188
jnielsen@westernresources.org
eguidry@westernresources.org

Joro Walker
Utah Office Director
Western Resource Advocates
1473 South 1100 East, Suite F
Salt Lake City, UT 84105
(801) 487-9911
jwalker@westernresources.org

Sarah Wright
Executive Director
Utah Clean Energy
917 2nd Avenue
Salt Lake City, UT 84103
(801) 359-7028
sarah@utahcleanenergy.org

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