BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of	)	
PacifiCorp for Approval of a 2009	)	Docket No. 05-035-47
Request for Proposals for Flexible	)	
Resource	)	
	)	

COMMENTS OF WESTERN RESOURCE ADVOCATES ON PACIFICORP'S DRAFT 2012 REQUEST FOR PROPOSALS

Western Resource Advocates (WRA) requests that the Utah Public Service Commission (Commission) accept these comments on PacifiCorp's draft 2012 Request for Proposals for Baseload Resources (2012 RFP).

I. SUMMARY OF COMMENTS

WRA has serious concerns about the scope and direction of the draft 2012 RFP.[1] PacifiCorp, through its evaluation of climate change risk in the IRP process and the commitments made on integrated gasification combined cycle (IGCC) technology and other issues as part of the MidAmerican acquisition in Docket No. 05-035-47, has begun to show important leadership in grappling with the some of the economic risks to ratepayers of climate change regulatory risk. Regrettably, WRA sees the current draft 2012 RFP as including several significant steps backwards from the progress made in the IRP and merger commitments.

The Energy Resource Procurement Act establishes a public interest standard for Commission review of the RFP document, taking into account a series of factors including

[1] Before discussing our concerns with the RFP 2012 in more detail, WRA would like to note that it has been an active participant and strong supporter of PacifiCorp's IRP process. WRA has publicly acknowledged some of PacifiCorp's analysis of climate risk and on IGCC as industry models in its publications. See, e.g., Western Resource Advocates, "A Balanced Energy Plan for the Interior West," p.51; available at http://www.westernresourceadvocates.org/energy/clenergy.php. WRA was also a signatory and supporter of the stipulation reached in MidAmerican's acquisition of PacifiCorp before this Commission and the Wyoming Public Service Commission approval proceedings and within the environmental community.

lowest reasonable cost, reliability, short-term and long-term impacts, financial impacts on the affected utility, and risk. WRA believes that the RFP, as currently drafted, focuses too narrowly on costs and financial impacts to the utility and gives inadequate attention to long-term and short-term impacts and risk. In particular, the RFP does too little to address the growing risk of global climate change.

WRA is deeply troubled by the Company's selection of two to three pulverized coal units totaling up to 1,690 MW during the 2012-2013 timeframe as utility benchmark options in the RFP. For the reasons described in these comments, WRA believes that the construction of these resources would be highly risky for PacifiCorp and its customers – not to mention the citizens of Utah, the Rocky Mountain West and, indeed, the entire planet -- due to their high emissions of CO2 and limited flexibility for capturing and sequestering those emissions. If the 1,690 MW of coal that are being used as benchmark options were actually built, the plants would emit about 13 million tons of CO_2 per year.[2] Over a sixty-year life, if their CO_2 emissions were not captured and sequestered, the plants would emit about 780 million tons of CO_2. WRA objects most strenuously to the Company's selection of a 750 MW pulverized coal unit in 2013 as the benchmark option for replacing front office transactions without any analysis of resource alternatives and timing in the IRP process or anywhere else.

IGCC, with its more efficient design, reduced water use and ability to capture and store its CO2 emissions, is poised to displace pulverized coal as the preferred technology for electricity generation from coal in the very near future. Multiple studies have confirmed that

[2] Estimated emission from the plant based on assuming an 85% capacity factor and 2050 lbs CO_2/MWh emissions rate. Utah emissions estimate based on data from EIA, *State Electricity Profile, 2004*, which indicates 38.2 million MWh of net generation in Utah in 2004 with an average CO_2 emissions rate of 2,029 lbs CO_2/MWh, or CO_2 emissions of about 38.8 million tons from electric generation in 2004.

IGCC is the least expensive way to generate electricity from coal once the costs of capturing and storing the carbon emissions are included. *See* Attachment 3.

WRA recommends that a far more advisable strategy than a massive build out of pulverized coal plants would be to focus on bridging options, like short-term transactions, demand-side management (DSM), renewable energy resources and QF power, for deferring these major capital expenditures to gain greater clarity on future climate change regulations and until such time as IGCC technology can be deployed. Towards, this end, WRA recommends that the Commission heed the Independent Evaluator's recommendations (IE) for building greater flexibility into the resource selection and approval framework as it relates to IGCC. WRA has some additional recommendations towards this end, which are discussed below. Most importantly, the Company should begin work on an IGCC front-end engineering design (FEED) study immediately.

II. CONSISTENCY OF DRAFT 2012 RFP WITH ENERGY RESOURCE PROCUREMENT ACT PUBLIC INTEREST FACTORS

The Energy Resource Procurement Act established a more prominent role for the Commission in reviewing and approving electric utility procurement decision. This will be the first case under the new Act brought to the Commission for approval. WRA respectfully submits that the Act grants the Commission both the latitude and the responsibility to ensure that the RFP process is aligned with the public interest. WRA encourages the Commission to exercise its considerable latitude to ensure that utility procurement decisions are in the long-term best interest of Utah. WRA believes it is especially important for the Commission to exercise that responsibility in the present case given the magnitude of the investment involved and the uncertainties surrounding the electric utility sector in the coming decades.

A. Senate Bill 26 Public Interest Standard

The public interest standard for Commission review of draft RFP's is set forth at UCA § 54-17-201(2)(c)(ii):

> In ruling on the request for approval of a solicitation process, the commission shall determine whether the solicitation process:
> * * *
> (ii) is in the public interest taking into consideration:
> (A) whether it will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to the retail customers of an affected electrical utility located in this state;
> (B) long-term and short-term impacts;
> (C) risk;
> (D) reliability;
> (E) financial impacts on the affected electrical utility; and
> (F) other factors determined by the commission to be relevant.

WRA would like to highlight certain key aspects of the statutory standard. First, the standard is a public interest standard, taking into consideration a series of factors. Ratepayer cost is one of those factors, as it should be, but ratepayer cost must also be balanced with long-term and short-term impacts, risk, reliability, financial impact to the utility, and other factors. In addition, the standard emphasizes lowest "reasonable" cost. If, for example, a portfolio of resources creates unacceptable levels of risk or has unacceptable impacts, it should not be accepted, even if it is determined by the production cost modeling to be the least-cost outcome. The same qualifications would apply to the other factors enumerated in the statute. At this stage, the Commission is not approving resource selections; but rather, it is reviewing the RFP document. However, WRA encourages the Commission to exercise vigilance in reviewing the RFP to ensure that the full costs, risks and impacts of resource options are identified and evaluated through this RFP process, and to ensure that certain emerging resource alternative are not foreclosed early in the process.

WRA is deeply concerned that the 2012 RFP, as currently drafted, gives insufficient emphasis to the risks and short-term and long-term impacts of the resource options that will be solicited and evaluated as part of this RFP. Further, because of certain limiting provisions in the RFP, bidders may decide to forego bidding certain resource options with lower risk profiles but potentially higher near-term electricity costs, because the long-term value of the project may not be fully recognized in the evaluation process. Most importantly, given the problem of global climate change, the draft RPF gives inadequate attention to the risks and impacts faced by Utah ratepayers and the state from such a major build-out of pulverized coal units.

B. Impacts and Risks of Climate Change

One of the greatest risks that PacifiCorp and its customers face is regulation to curtail emissions of greenhouse gas emissions (GHGs), the most abundant of which is carbon dioxide (CO2). According to the U.S. Energy Information Administration (USEIA), in 2004, about one-third of all U.S. GHGs were emitted by electric utilities and 82 percent of these utility emissions were attributable to the combustion of coal.[3] Simply put, coal combustion by U.S. electric utilities is a major contributor of CO2. There can be little doubt that, when the U.S. faces up to its responsibility to curtail emissions of GHGs, emissions of CO2 by coal-fired power plants will be regulated or taxed, perhaps heavily so.

What is the likelihood that emissions of CO2 by PacifiCorp and other U.S. utilities will be regulated or taxed? WRA believes that imposition of financial penalties on emissions of CO2

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[3] Derived from "Greenhouse Gas Emissions Flow, 2004," U.S. Energy Information Administration, December 2005, prepared for U.S. Senate Committee on Energy and Natural Resources.

by utilities is a near certainty within the lifetime of new coal power plants, and is likely within the next decade. Any utility that does not plan for and hedge this risk threatens the financial stability of both its customers and its shareholders.

Our judgment on the likelihood of CO_2 regulation of CO_2 is based, first, on the overwhelming scientific evidence that human activities are warming the climate, with the potential for serious harm to humans and the species with which we share this planet, and, second, on the multiplicity of initiatives to control GHGs that are sprouting up across the U.S. and elsewhere.

As to the science, no one disagrees that atmospheric CO_2 traps a portion of solar radiation reaching the Earth, thereby warming the atmosphere. Results from the European ice-coring project in Antarctica reveal that the amount of CO_2 in the atmosphere and global temperatures have been closely coupled for the last 650,000 years. They also show that the amount of CO_2 in the atmosphere (380 parts per million and climbing) has never been higher over the last 650,000 years than it is now.[4] Not surprisingly, global temperatures have been warming. Temperature records with adequate global coverage exist only for about the last 150 years. In 1995, the World Meteorological Organization has found that within this period, the last ten years (1996-2005), are the warmest years on record.[5] Evidence like this resulted in the joint statement in 2005 to the Group of 8 by the science academies of Brazil, Canada, China, France, Germany, India, Italy, Japan, Russia, the United Kingdom and the United States in 2005, which

[4] U. Siegnethaler et. al., Science 310, 1313, November 25, 2005.
[5] World Meteorological Organization, Press Release, Dec. 15, 2005, WMO-No. 743.

said: "The scientific understanding of climate change is now sufficiently clear to justify taking prompt action."[6]

The need for "prompt action" derives from the longevity of emissions of CO2 in the atmosphere. Much of the CO2 we are emitting today will still be in the atmosphere decades from now. Indeed, the full impact of the GHGs already in the atmosphere will not be felt until around 2050. Even if we stopped emitting GHGs now, the climate will continue to warm for decades.[7] The result is that we cannot wait to reduce our GHG emissions until some later time. Indeed, scientists say that to stabilize Earth's climate at an average temperature 2 degrees Fahrenheit higher than today's temperatures will require at least a 70 percent <u>reduction</u> in CO2 levels by 2050 from 1990 levels.[8] However, we are marching forcefully in the other direction. According to the USEIA, total GHG emissions in the U.S. jumped by 2 percent from 2003 to 2004 and are now 16 percent higher than in 1990. EIA projects a 38 percent increase in GHG emissions by 2030 unless new policies are implemented.[9]

Some of the impacts of global warming are likely to be severe. For example, sea-level rises of 10-20 feet attributable to warming that melts land-based Greenland and Antarctic ice, possible within the next 100-200 years, could create tens of millions of refugees in Asia and flood parts of the coastal U.S.[10] A study published in the Journal of Nature in 2004 estimated that if temperatures rise more than 3.6 degrees Fahrenheit from today's levels—today's and future emissions under a business-as-usual strategy commit us to this rise—around one-third of

[6] Joint Science Academies Statement: Global response to Climate Change at the Gleneagles G8 Summit, 2005.
[7] "Stabilisation and Commitment to Future Climate Change," Hadley Centre report, United Kingdom: Met Office, October 2002.
[8] "The Weathermakers, How Man is Changing the Climate and What it Means for Life on Earth," Tim Flannery, Atlantic Monthly Press, New York, 2005, p. 168.
[9] U.S. Energy Information Administration, Annual Energy Outlook 2006.
[10] *See* op. cit., fn 5, pp. 142-150.

all the species that inhabit the Earth will go extinct.[11] Finally, there is widespread concern that global warming will encourage extreme weather events, such as stronger hurricanes and deeper droughts.[12] These factors suggest that, in the name of sustainability of the planet's environment and for the benefit of our children and grandchildren, we should be taking steps now to reduce GHGs, especially in the electric utility sector. Consistent with the public interest mandate of UCA § 54-17-201(c)(ii) and its consideration of risk and long-term and short-term impacts, WRA submits that the scientific evidence of climate change provides compelling justification in and of itself for a strong showing of Commission support for prompt action by the state's electric utilties to begin managing, stabilizing and ultimately reducing their CO2 emissions.

On top of the compelling scientific evidence, the growing momentum of support both domestically and internationally toward controlling GHG emissions provides additional justification for PacifiCorp to begin managing, stabilizing and reducing their CO2 emissions to avoid financial risk to shareholders and ratepayers. The Kyoto Protocol, requiring industrialized countries to reduce their emissions of GHGs to 5 percent less than 1990 levels took effect in February 2005. The Bush Administration rejected Kyoto in 2001. However, this has not impeded American companies from adopting programs to reduce emissions, including American Electric Power, Cinergy, 3M, Eastman Kodak, General Motors, IBM, Pfizer, Johnson and Johnson and General Electric.[13] Some electric utilities, including Exelon and Duke Energy, have gone further, saying that they would either welcome or accept mandatory caps on their GHG

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[11] C.D. Thomas et. al., "Extinction Risk from Climate Change," Nature 427 (2004), pp. 145-148.
[12] See "U.S. Environmental Protection Agency, Global Warming – Impacts," http://yosemite.epa.gov/oar/globalwarming.nsf/content/impacts.html.
[13] As of August 12, 2006, the U.S. Environmental Protection Agency lists 93 companies, including eight electric utilities, but not PacifiCorp, that have made voluntary commitments to reduce GHGs a part of EPA's Climate Leaders Program. See http://www.epa.gov/climateleaders/partners/ghggoals.html.

emissions.[14] In 2003 there were 43 votes in the U.S. Senate for legislation that would have required all sectors of the U.S. economy to limit GHGs to year-2000 levels by 2010.[15] In 2005 the Senate adopted a non-binding resolution declaring that GHGs are linked to climate change and calling upon Congress to pass a national program of mandatory, market-based limits on GHGs.[16]

Furthermore, state and local governments in the U.S. have been taking action to evaluate and address GHG emissions. For example, seven states across the northeast U.S. are participating in the Regional Greenhouse Gas Initiative (RGGI). In December 2005 these states signed a memorandum of understanding that requires stabilization of CO2 emissions from the region's power plants at current levels from 2009 through 2014, followed by a 10 percent reduction in such emissions by 2019.[17] On August 15, 2006, the RGGI members announced agreement on proposed rules for implementing a CO2 cap and trade program. In June 2005 the U.S. Conference of Mayors unanimously adopted a resolution that calls for actions at the federal, state and local levels to beat Kyoto targets by reducing GHG emissions 7 percent below 1990 levels by 2012. As of August 12, 2006, 279 municipalities had accepted the challenge contained in the resolution.[18] Here in Utah, Salt Lake City, Moab and Park City have joined the Conference of Mayors' challenge. In 2002, Salt Lake City pledged to cut the city's greenhouse emissions by 21 percent by 2012, and it has already exceeded that goal seven years early.[19]

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[14] Grist Magazine, April 6, 2006.
[15] "Climate Change," http://www.aenvironment.com/ClimateChange.html.
[16] Vote of the U.S. Senate on Amendment 826 to H.R. 6, June 22, 2005, http://www.senate.gov/legislative/LIS/roll_call_lists/roll_call_vote_cfm.cfm?congress=109&session=1&vote=00148.
[17] See Regional Greenhouse Gas Initiative, Participating States, http://www.rggi.org/states.htm
[18] See website of the Office of the Mayor, City of Seattle, http://www.seattle.gov/mayor/climate/.
[19] "As Cities Cut CO2, Utahns' lifestyles adding to Problem," http://www.sltrib.com/ci_4166552

State actions to reduce GHG emissions are also underway across the west. Since 1997, the Oregon Energy Facility Siting Council has set CO_2 standards for new power plants.[20] In 2003 the governors of California, Oregon and Washington called for a regional greenhouse initiative to reduce GHGs.[21] In 2004 Washington enacted legislation requiring that at least 20 percent of CO_2 emissions from new fossil fuel power plants be either taxed or mitigated.[22]

In June 2005 Governor Schwarzenegger issued an executive order establishing targets for California to reduce GHG emissions to 2000 levels by 2010, to 1990 levels by 2020 and to 80 percent below 1990 levels by 2050. In October 2005 the California Public Utilities Commission issued a policy statement in which it directed its staff to investigate the adoption of a GHG emissions performance standard for long-term utility resource procurements that is no higher than the GHG emissions of a combined-cycle natural gas turbine.[23] The California PUC has since initiated a rulemaking docket to implement this standard. And in November 2005 the California Energy Commission adopted the same standard for California utility procurements.[24]

States in the Interior West are also taking action to establish limits on GHGs. Governors Napolitano (AZ) and Richardson (NM) have created climate change advisory groups in their respective states.[25] Governor Richardson's executive order establishing the New Mexico group contains targets to reduce GHG emissions to 2000 levels by 2012, to 10 percent below 2000

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[20] *See* John Savage, "Oregon's Carbon Dioxide Standard for New Energy Facilities," Oregon Office of Energy, April 26, 2000, p.6.

[21] Statement of the Governors of California, Oregon and Washington to Address Global Warming, September 22, 2003.

[22] H.B. 3142, http://www.leg.wa.gov/pub/billinfo/2003-04/Pdf/Bills/House%20Passeed%20Legislature/3141-S.PL.pdf.

[23] "Policy Statement on Greenhouse Gas Performance Standards," California Public Utilities Commission, October 6, 2005.

[24] "California Energy Commission, 2005 Integrated Energy Policy Report, Committee Final Report," November 2005, CEC-100-2005-007-ES, p. 18.

[25] Office of the Governor of Arizona, Executive Order 2005-02; Office of the Governor of New Mexicom Executive Order 05-033.

levels by 2020 and to 75 percent below 1990 levels by 2050. In February 2006 Governors Napolitano and Richardson launched the "Southwest Climate Change Initiative," designed, among other things, to identify options for reducing GHG emissions.[26]

C. Treatment of Climate Change Risk in RFP Bid Evaluation Process

PacifiCorp, through its IRP process and merger commitments, has begun to show important leadership in grappling with the some of the economic risks to ratepayers of climate change. The Company received national recognition for being one of the first electric utilities in the country to acknowledge the risk of climate change in the resource planning process in its 2003 IRP. PacifiCorp's IRP includes robust scenario analyses of various portfolio alternatives at various levels of CO2 emissions costs. Further, its 2004 IRP includes a very informative analysis of the break even point for CO2 emissions costs at which IGCC technology overtakes pulverized coal in terms of cost to ratepayers (as measured in terms of net present value of revenue requirements). MEHC and PacifiCorp also committed, as part of the stipulations reached in Docket No. 035-35-54, to form IGCC and climate change working groups to begin sharing information and (hopefully) provide a forum for developing system wide solutions to some of the challenges faced by the company, regulators and ratepayers in confronting climate change. WRA sees these working groups as integral to building upon and accelerating the some of the early progress PacifiCorp has made on these important issues.

However, WRA is deeply concerned that the draft 2012 RFP includes several significant steps backwards from the progress made in the IRP process and merger commitments with respect to the treatment of climate change risk precisely when PacifiCorp should be moving

[26] "Governors Napolitano and Richardson Launch Southwest Climate Change Initiative, News Release, February 28, 2006.

forward.[27] In other words, much of PacifiCorp's important work on evaluating CO2 risk in the IRP evaluation stage has not been transferred to the resource acquisition stage. Currently, the primary, if not only, means by which PacifiCorp will reflect CO2 risk in the RFP process will be through the use of the $8 per ton CO2 adder. WRA believes that PacifiCorp's inclusion of a CO2 adder in the RFP evaluation process, while important, is insufficient to capture the magnitude of climate change risk faced by the company and ratepayers.

As an initial matter, the $8 per ton CO2 adder is at the low end of the range of reasonable values. As previously mentioned, many scientists believe that, to stabilize global temperatures at no more than 2 degrees Fahrenheit more than today's temperatures in order to avoid some of the more extreme consequences of global warming, it will be necessary to reduce CO2 emissions by at least 70 percent from today's emissions levels. Achieving this goal will require not only that new power plants emit or offset 100 percent of their CO2 but also that existing plants offset roughly for 70 percent of their emissions as well. Are there enough verifiable offsets available to achieve these goals in order to accommodate a new round of coal plants over their projected useful lives? This remains to be seen. But even if there are, it does not seem likely that under this scenario the cost impacts of CO2 emissions offsets would remain at or near at $8 per ton while only escalating at inflation.[28] Rather, it is reasonable to expect that the cost impact of CO2

[27] First and foremost, WRA objects to PacifiCorp's selection of a 750 MW pulverized coal as the benchmark option for replacing front office transactions beginning in 2013. That issue, along with PacifiCorp's other benchmark options, are discussed in more detail below in the context of the merger commitments on IGCC. Here, WRA will provide comments on the Company's treatment of CO2 risk in the RFP solicitation itself.

[28] In the IRP process, WRA has recommended that the Company consider escalating its base case assessment of CO2 emissions costs at an escalation rate higher than inflation as an alternative to one or more of the high-end CO2 risk sensitivities. We believe this represents a more realistic scenario than the high-end and base case emissions cost scenarios.

emissions regulations will exceed $8 per ton well within the lifetime of any new generation resources acquired as a result of this RFP.

An additional point of reference for evaluating the reasonableness of the $8 per ton CO2 adder are the current prevailing market prices for CO2 emissions credits in the European Union. The European Union Allowance market covers about 10,000 large industrial and power generating sources. At the time PacifiCorp selected the $8 adder in 20013, the European market was just getting started and European countries' Kyoto obligations had not yet begun. At the time, emission credits on that exchange were trading in the $8 range as well. Since then, prices have increased and are now trading in the $20 range.[29]

Moreover, the use of a low-end CO2 adder in the RFP will not fully capture the option value of IGCC technology, which, if properly designed and sited, is able to capture and store is CO2 emissions in geologic formations or use them for enhanced oil recovery. As currently proposed, the Company will rank short-listed bids based solely on their projected impacts on utility revenue requirements. There is nothing in the RFP document which indicates that the ability of a project to capture and store its CO2 emissions will be factored into the resource evaluation process, either at the initial screening stage or the short-list evaluation stage. For example, it does not appear that the Company's 2014 IGCC benchmark option will receive *any* economic value in the bid evaluation process for proposing a facility that is designed to be carbon capture ready. To the contrary, such a project could actually be penalized in the bid evaluation process for the incremental costs associated with making it carbon capture capable, because it would be less competitive vis-à-vis a project that lacks this characteristic. Similarly,

[29] As of August 2, 2006, the price of European Union Allowances was about $21 per metric ton of carbon dioxide.

there is no incentive within the RFP evaluation framework for a bidder to locate a facility within reach of enhanced oil recovery facilities or other sequestration opportunities, even though such access could prove to have significant long-term value for ratepayers and the environment. We believe this RFP framework sends the wrong signals to bidders and is inconsistent with the public interest under UCA § 54-17-201(2)(c)(ii).

It is WRA's understanding that the CO2 risk sensitivity analyses performed in the IRP will not be carried over to the RFP bid evaluation process, either as part of the capacity expansion model (CEM) or the planning and risk model (PAR).[30] Instead, the RFP will rely solely on a single expected value analysis for reflecting CO2 risk in the bid evaluation process, which, as discussed previously, greatly understates the potential risks to ratepayers and the impacts to Utah of climate change.

WRA recommends that the RFP should be revised to include a more complete analysis of the cost, risks and impacts of global climate change for the Company's procurement decisions. First, the Company should investigate including a wider range of CO2 risk sensitivities in the CEM and PAR short-listed bid evaluations. To the extent that a single value must be used, we suggest using more current European Union market prices and trends as points of reference for selecting that value.

WRA recommends that the RFP should explicitly include as evaluation criteria whether bids to construct new generating facilities will be designed to be carbon capture ready and whether the facilities have been sited with ready access to sequestration opportunities. Bidders should be put on notice that failure to account for these evaluation criteria may serve as grounds

[30] *See* PacifiCorp's June 2, 2006 PowerPoint presentation entitled, "Pre Draft 2012 Request for Proposals Stakeholder Presentation."

for rejection of the bid. Indeed, WRA believes it would be unwise for the Company to enter into long-term agreements with any project that does not demonstrate a long-term strategy for managing its CO2 emissions. To the extent that a project developer for a major baseload unit has not carefully thought through this issue, it raises serious questions about the merits of the project.

WRA recommends that the RFP explicitly state that the Company is actively seeking and prefers bridging options that can defer or reduce the need for irrevocable investment in expensive and long-term resources. Right now, the RFP makes no mention of the bridging concept. Unbelievably, it explicitly excludes from consideration contracts less than ten years, which are precisely the types of resource bids that should be encouraged. The RFP also excludes from consideration bids for resources that are greater than 5 MW but less than 100 MW and load-curtailment bids greater than 25 MW. As discussed below, we believe these limitations are inconsistent with the company's obligations under MidAmerican acquisition commitment U16(a). We presume these restrictions were designed in part to conform to the definition of "significant energy resource decision" under the Energy Resource Procurement Act. But regardless of whether the Company handles short-term and smaller-scale bids through this RFP or concurrently through some other process, PacifiCorp should aggressively seek out these opportunities, and the RFP should explicitly discuss the bridging resource concept so that bidders may design their proposals accordingly.

D. Water Use and Availability

Utah is situated in the heart of the western United States where water is quickly becoming a scarce commodity. Utah is the second most arid state in the country. Under the public interest standard of the Energy Resource Procurement Act, the Commission has the authority to review procurement decisions for long-term and short-term impacts and risks. WRA recommends that the Commission use this authority to place greater scrutiny on the location of proposed generation facilities and the choice of water cooling technologies for bids and benchmark options in the RFP. Currently, if two bids are received that are identical in every respect except that one of the bidders deploys more efficient cooling technologies at a higher up-front cost, that bidder will lose out in the bid evaluation process without any assessment of whether the incremental costs are warranted. We believe this is the wrong incentive to send potential bidders and is inconsistent with the Commission's public interest mandate under UCA § 54-17-201(2)(c)(ii). Rather, the RFP should be revised to make explicit that facility location and water cooling technology will be used as evaluation criteria during the bid evaluation. In addition to demonstrating adequate water rights as part of the due diligence phase, a bidder should be required to identify how its proposed project would affect projected trends in water use and availability within the basin where the project is located. In addition, a bidder should explain its choice of water cooling technology, identify incremental improvements in water efficiency that can be made, and provide a cost analysis for such incremental improvements, and tradeoffs with other factors like fuel use and air emissions. A discussion of trends in water consumption and availability, as well as the relative efficiency of different technologies, is included as Attachment 1.

E. Air Permitting and Multi-state Approval Risks

An additional risk faced by the Company in procuring new resources is whether the project will see the necessary permits and multi-state approvals in a timely manner. WRA submits that this risk is the most pronounced in the case of pulverized coal development. A significant potential advantage of IGCC technology for the PacifiCorp system is that it may face reduced risks of delays in permitting and regulatory approvals relative to pulverized coal plants. The Company has already acknowledged during the IGCC technical conferences in this docket that the construction lead-time for IGCC is projected to be 4 to 6 months shorter than for supercritical pulverized coal. Because of its improved environmental performance, IGCC may face reduced public opposition in air permitting and siting proceedings. As evidenced by the Oregon PUC order on PacifiCorp's 1004 IRP, IGCC may also have some advantages from a multi-state approval standpoint.

III. CONSISTENCY OF 2012 DRAFT RFP WITH MIDAMERICAN ACQUISITION COMMITMENTS

A. Analysis of the 2012 Pulverized Coal Benchmark Option

Subsequent to the release of the 20014 IRP Update, PacifiCorp made a series of important commitments on resource planning as part of the state commission approvals of MidAmerican's acquisition of PacifiCorp. WRA regards these commitments as significant improvements over the November 2004 IRP Update. Of particular importance to the present RFP, the Company made several important commitments with respect to consideration of IGCC technology for its baseload resource needs in the 2012-2014 timeframe.

PacifiCorp's November 2004 IRP Update identifies two coal-fired generating units in its preferred portfolio (Table 5.1, p.45). The first is a 575 MW brownfield coal plant in Utah for a projected in service date of calendar year 2012. The second is a 500 MW brownfield coal plant in Wyoming with a projected in service date of calendar year 2014. It does not include a pulverized coal unit in 2013. The Updated Action Plan (Table 5.2, p.46) includes the procurement of the 575 MW Utah coal plant for 2012. It does not include any action plan steps for the Wyoming coal resource in 2014. Because the preferred portfolio did not include any coal-fired generation in 2013, it logically did not identify any action plan items for this resource.

Not uncoincidentally, the MidAmerican commitments on IGCC directly track the Company's preferred portfolio under the November 2004 IRP Update for the 2012-2014 timeframe. Commitment U15(a) refers specifically to the 2012 resource need:

> MEHC and PacifiCorp commit to study the economics and viability of an IGCC option and will present the results of this study as a resource alternative to inform the resource selection and RFP process under consideration in Docket 05-035-47. PacifiCorp will also file the results of this study and the draft RFP with the Commission pursuant to the provisions of SB 26. PacifiCorp will suggest procedural schedules that will facilitate this commitment. As soon as practicable, but not later than three months after the closing of the transaction, PacifiCorp will provide to the parties estimated cost and timeline ranges for completion of an IGCC project, as well as potential resource alternatives if an IGCC design is not reasonably achievable in time to economically meet the resource need presently identified in 2012 from a customer and shareholder perspective.

Commitment U15(a) imposes several obligations on the Company with respect to the 2012 resource need. First, the Company commits to study the economics and viability of an IGCC option. This they have done within the context of the IGCC technical conferences in this docket. In addition, the Company is obligated to present the results of the study as a "resource alternative to inform the resource selection and RFP process" in this docket. As of the filing of these comments, WRA has questions about whether this latter requirement has been met. The company did present cost data on IGCC build options at Hunter and Jim Bridger as part of the IGCC technical conferences in this docket. However, it is not clear to WRA how this information is going to be presented as a "resource alternative" that will "inform the resource selection and RFP process" in this docket. This RFP process will necessarily involve bifurcated proceedings. This first stage involves approval of the RFP docket itself. The next stage, presumably in the fall 2007 or so, will involve the actual selection of the resources to meet the 2012 resource need. Because PacifiCorp has declined to propose an IGCC self-build option for the 2012 resource need, WRA questions whether the Commission will have the information necessary to make an informed decision on IGCC as a resource alternative when it comes time in fall 2007 to review the company's selection of resources to fill the 2012 resource need, as is contemplated by Commitment U15(a). WRA acknowledges that U15(a) did not obligate the Company to come forward with a self-build option for the 2012 resource need, which it elected not to do. However, WRA respectfully submits that the Company is still obligated to make an IGCC resource alternative available for evaluation purposes so that, at the time the Commission, regulators and stakeholders are reviewing the selection of resources in fall 2007, they can make informed and independent decisions on whether they agree with the Company's election not to propose an IGCC self-build option for the 2012 resource need.

Commitment U15(a) creates two additional obligations with respect to IGCC. First, in anticipation of a Company determination that it would not be practicable to build an IGCC unit by 2012, the Company agreed to present estimated costs and timeline ranges for completion of an IGCC project. The Company presented this information at the IGCC technical conferences in this docket. Second, assuming the company determined it would not be practicable to develop an IGCC unit by 2012, the company also committed to identify "potential resource alternatives if an IGCC design is not reasonably achievable in time to economically meet the resource need presently identified in 2012 from a customer and shareholder perspective." The Company presented this analysis of resource alternatives at the technical conferences. However, the Company interpreted this term "resource alternatives" very narrowly, and presented information only on the construction of new long-lived fossil fuel gas and coal units. The Company did not present any information on other potentially available resource alternatives or strategies for bridging the gap, like renewable energy resource, demand-side management resources, short-term market purchases, QF power, or lowering the reserve margin.

This narrow interpretation of the bridging concept was contrary to WRA's expectation and understanding of what this analysis would entail. Based on stakeholder feedback at the draft RFP presentations to stakeholders, it appears to be inconsistent with the expectations of a significant number of other stakeholders across the PacifiCorp system as well.

B. Analysis of the 2013 Pulverized Coal Benchmark Option

WRA recommend that the Company's 2013 benchmark option should be eliminated from the 2012 RFP. WRA does not object in principle to idea of evaluating whether to replace 700 MW of front-office transactions, which are currently priced at the forward price curve, with more stably priced resources or longer term market purchases. However, a decision whether to replace 700 MW of what are essentially short-term (1 to 5 years) front office transactions with a physical asset expected to cost well in excess of a billion dollars with an expected life of 60 years raises immensely important tradeoffs between costs, risks, uncertainty, and long-term and short-term impacts that have not been analyzed in the IRP process or in any other forum. As stated previously, a 750 MW pulverized coal benchmark for 2013 does not show up anywhere in preferred portfolio or action plan to the Company's 2004 IRP or the October 2004 IRP update.

The choice of a 750 MW pulverized coal unit as the 2013 benchmark option raises other serious questions that have not been addressed. Notably, the Company's load forecast shows that it is the summer peak that is driving much of the load growth on the East side of the PacifiCorp system. Yet, there has been no analysis in the IRP process or elsewhere of how a 2013 baseload resource -- with a capacity factor presumably expected to approach 90 percent -- is the appropriate utility benchmark option for meeting what appears to be primarily a need for meeting a growing summer peak.

Furthermore, there has been no analysis performed as to whether the year 2013 is the appropriate timeframe to begin replacing these front-office transactions. The 700 MW of front-office transactions are included in every year of the resource planning period. They do not begin in 2013. Yet, no analysis has been performed as to whether there are other resource options such as increased investment in DSM, QF power, renewable resources or other options with much shorter development lead-times that can begin displacing front office transactions much sooner than 2013.

WRA questions whether a 2013 in-service date for a fifth unit at Jim Bridger is even realistic. The Company has acknowledged that the development of a coal unit and the associated transmission upgrades at Jim Bridger will be subject to public environmental review requirements under the National Environmental Policy Act (NEPA). In addition, significant air quality issues in and around Jim Bridger may raise unique air permitting challenges and further heightens the risk of delay in meeting a 2013 in-service date. Moreover, the Company's selection of a 750 MW pulverized coal as its 2013 benchmark option, without first going through the IRP process, could create additional complications and potential delays from a multi-state approval standpoint. Given the uncertainties surrounding air permitting, NEPA compliance, and multi-state approval of a pulverized coal unit, it may be the case that a more realistic expected in-service date for a Jim Bridger expansion would be 2014 or later, in which case the Company would be obligated under merger condition U15(c) to evaluate IGCC as a self-build option.

Further, the selection of a 750 MW pulverized coal unit as the 2013 benchmark raises serious process concerns. Commitment U16, which was drafted to track the 2012 and 2014 baseload resource needs identified in the October 2004 IRP Update, never contemplated adding a pulverized coal plant in 2013. What the acquisition commitments did contemplate were a series of technical studies and working groups on a variety of resource development issues, ranging from a DSM market potential study, transmission studies and upgrades, a reevaluation of the 1400 MW renewable energy target, and the creation of global warming and IGCC working groups -- all of which were structured to feed into and inform the IRP process. Unlike these commitments, which were subject to extensive discussion, negotiation and Commission review and approval in all the states, the 2013 benchmark option was selected outside the IRP process and introduced for the first time after the merger had been approved. If the Company solicits bids as part of this RFP to fill that resource need before the various studies and deliberations have been completed, it will greatly diminish their value. The replacement of front office transactions with a 2013 benchmark option, if allowed to go forward as part of this RFP, risks undermining public involvement in the IRP process and upsetting the balance struck among the parties across PacifiCorp's jurisdictions as part of the MidAmerican acquisition proceedings.

C. Analysis of 2014 IGCC Benchmark Option

To the Company's credit, since the time it first presented its benchmark options to stakeholders at the May 2006 technical conference, the Company has agree to present an IGCC benchmark option for the 2014 resource need, in accordance with Commitment U16(b) and (c). WRA is also encouraged to learn that the Company decided to apply for the Department of Energy IGCC tax credits as part of the 2006 solicitation cycle.

However, the Company's decision to present an IGCC self-build benchmark option to meet the 2014 resource need in accordance with commitments U16(b) and (c) does not thereby relieve it of its separate obligation under commitment U16(a) to present IGCC as a resource alternative to inform the selection of the 2012 resource need. Nor does it relieve the Company of its obligation to present a more complete analysis of bridging resource options under commitment U16(a), in the event that IGCC is not ready in time to meet the 2012 resource need.

Since 2014 is the first year in which the Company has indicated it is prepared to propose an IGCC self-build option, WRA recommends that the Company treat is 2014 IGCC benchmark in the 2012 RFP as the IGCC "resource alternative" discussed in merger commitment U16(a), with 2014 being the earliest date it expects IGCC could be made available as a utility self-build option to meet the 2012 resource need. Under this approach, the Company would not seek to fill its 2014 resource need as part of this solicitation. This approach would be consistent with the Company's October 2004 IRP update action plan. It would also be consistent with Merger commitment U16(b), which contemplated evaluation of the 2014 resource need as part of the 2006 IRP cycle.

IV. RECOMMENDATIONS ON IGCC

A. Recent Trends in IGCC Development

The evidence is robust that IGCC could soon emerge as the preferred technology for generating electricity from coal. At roughly the same time resources procured as part of this RFP start coming on-line, we anticipate that pulverized coal technology will increasingly be seen as obsolete and unaffordable.

A number of developments suggest that the risks and costs of IGCC, especially when employing low-rank western coal, are on their way down. According to a recent PacifiCorp presentation to the IGCC Working Group, "General Electric has indicated that it will be making available a PRB coal optimization option, to its existing PRB capabilities, in the very near future."[31] The entrance of GE (and its partner Bechtel) into the IGCC/low-rank coal sweepstakes is encouraging. During the meeting, PacifiCorp also noted developments in Europe, including the entrance of the giant Siemens Corporation into gasification of lignite, as significant for developing the potential of U.S. low rank coal.[32]

PacifiCorp's comparison of the costs of IGCC and supercritical PC plants, as set forth in its slide presentation dated April 3, 2006 ("Request for Proposal, Technical Conference, Utah Docket 05-035-47") shows a somewhat larger cost spread, without carbon capture, than other studies. Recent cost estimates from EPRI are shown in Attachment 2. WRA has not had the opportunity to review the Worley-Parsons study in detail, as it just recently became available. Based on initial review, the Fixed O&M costs and environmental assigned to IGCC plants by

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[31] "Marketplace Updates & European Advanced Coal and CO2 Reduction Programs," Ian Andrews, Pacificorp and Bryce Freeman, Wyoming Office of Consumer Advocate, Slide 3, August 3, 2006.
[32] *Id.*, Slide 2.

Worley-Parsons look higher than those we have seen assigned to IGCC plants in other analyses.[33]

While IGCC may have somewhat higher incremental costs than pulverized coal, the relative economics of IGCC and pulverized coal plants change considerably when carbon capture equipment is included in the analysis. Rather than costing somewhat more, IGCC becomes the more economic technology when carbon capture is considered. This conclusion has been reached consistently in a number of comparative studies. Attachment 3 provides results from studies published by EPRI, Princeton University, Carnegie Mellon University, and the Massachusetts Institute of Technology comparing the economics of IGCC and pulverized coal with carbon capture. These studies indicate that, with carbon capture, the cost of producing electricity at a conventional pulverized coal plant is 18 to 32 percent more than at an IGCC plant.

Several new IGCC plants have been announced in the last year or two, including plants in Indiana, Illinois, Ohio, California, Minnesota and Washington, the last two of which are likely to use low-rank western coal.

Most recently, on August 15, 2006, Xcel Energy announced plans to develop a 300-350 MW IGCC facility for its Colorado service area using western coal at high altitude.[34] Of particular note, the project will be the first coal-fueled IGCC plant in the nation to capture a portion of its CO2 emissions. Xcel has stated it will begin engineering and design studies now, present the proposal to the Colorado PUC in fall 2007, and then commence construction in 2009 for a projected 2013 in-service date. Xcel anticipates the capital costs to range from $1400 to

[33] WRA has requested that the Company present additional information on its assessment of the fixed O&M costs estimates in the context of the IGCC working group.
[34] Xcel's press release is available at http://files.e2ma.net/4603/assets/docs/igcc_release_final.pdf. A joint Environmental Defense / WRA press release in support of the proposed IGCC project is available at http://www.environmentaldefense.org/pressrelease.cfm?ContentID=5399.

$1700 per kW, including the capture and storage of some portion of the CO_2 emissions. Xcel also states that it anticipates working with the Department of Energy and Congress to leverage federal funding opportunities.

B. Recommendations on Increasing Flexibility in the RFP

A primary goal of this RFP should be to allow for flexibility to adjust to a world that is changing rapidly in the face of global warming as well as the rapidly developing technologies that can help address global warming's costs and risks. The IE, in its June 2006 progress report, discusses some options for increasing flexibility in the RFP process to accommodate stakeholder interest in evaluating IGCC technology, including contract buyout provisions and the like. WRA believes these recommendations deserve serious consideration. WRA's additional recommendations for increasing flexibility in the RFP process are discussed below.

- **Revise RFP to Allow for Short-Term Bridging Options:** One of the most important steps that can be taken to secure a robust set of low-cost, low-risk portfolio options, including facilitating IGCC development, is to relax the rigid requirements of 10-year contract terms and 100 MW bid sizes to help identify bridging resource options to allow for greater consideration of IGCC technology. PacifiCorp should explicitly seek out such short-term options as part of this RFP.

- **Immediately begin work on a FEED study:** The March 3, 2006 Amendment to Stipulation in Docket No. 05-035-54 states at paragraph 16 that the "parties agree to support recovery, over a reasonable period, of prudent costs incurred with the IGCC studies in Commitment U16, consistent with Utah law and regulatory practice." WRA recommends that PacifiCorp begin work immediately on a front-end engineering and design (FEED) study for one or more IGCC units. The initial phase of a FEED study may take on the order of six months to complete. WRA fears that if the Company does not initiate a FEED study soon, it risks not having the detailed information available to fully evaluate an IGCC option at the resource approval stage of this process in the fall 2007. Indeed, given the Company's commitment to begin proposing IGCC benchmark options beginning in 2014, WRA questions why this work has not begun already.

- **Coordinate RFP timelines and evaluation efforts with the Wyoming Infrastructure Authority:** On July 17, 2006 the Wyoming Infrastructure Authority issued a Request for Proposals to elicit bids for the establishment of a public-private partnership to demonstrate production of energy from an IGCC plant in Wyoming that would qualify for federal financial support under section 413 of the Energy Policy Act of 2005 (EPACT). Proposals must be received by October 17, 2006, indicating the WIA's intent to move quickly to demonstrate IGCC with low-rank Wyoming coal.

- **Show flexibility on the lockdown date for benchmark options and timeline for resource approval**: As discussed previously, the market for IGCC development is rapidly evolving, including major new efforts on IGCC by GE and Siemens. WRA understands the logic behind requiring PacifiCorp to lock down the prices on its benchmark options by a date certain, but suggest that the same function could be served through vigilant IE oversight, so as not to foreclose new opportunities. In addition, it may be necessary to show some flexibility in the timeline for resource approval to enable IGCC participation in the RFP.

- **Consider Innovative Joint Ownership Arrangements:** The RFP should also allow for bidders to propose the development of syngas units for the sale of snygas to PacifiCorp, with PacifiCorp owning the balance of plant. Because the bidder would also be in operational control of the syngas unit, it may be willing to provide better performance guarantees than if it were to hand over operational control of the unit to the utility.

- **Take the lead in facilitating a dialogue among states on the PacifiCorp system to seek consensus on IGCC:** WRA recommends that the Utah Commission play a leadership role in seeking consensus among the states on IGCC development. While it may not be realistic to expect full consensus among all stakeholders, it may turn out to be less elusive than consensus among the states on the development of a pulverized coal unit. One forum for doing this may be through the IGCC working group.

Thank you for the opportunity to submit comments on the Company's 2012 RFP.

Respectfully submitted,

Joro Walker
Utah Office Director
Western Resource Advocates
425 East 100 South
Salt Lake City, Utah 84111

Eric C. Guidry
Energy Program Staff Attorney
Western Resource Advocates
2260 Baseline Road, Suite 200
Boulder, Colorado 80304

August 16, 2006

ATTACHMENT 1: WATER CONSUMPTION TRENDS IN UTAH

Urban populations and water demands are expected to double in the next four decades and some river basins are planning on developing significant additional water supplies to meet growing demand, potentially leading to large environmental impacts. Because water is at such a premium, it is essential that future water development, including potential water use by proposed energy projects, be closely scrutinized to determine if it is in the long-term public interest.

State agencies expect that, statewide, Utah will have enough water supplies to meet the projected 2050 demand during an average water year; Utah estimates a total of 790,000 acre-feet of undeveloped water supply is available, enough to meet the increased demand of 622,000 acre-feet.[35] But population growth will put stress on some water supplies, especially in fast-growing areas like the Jordan River and Utah Lake Basin, and year-to-year and seasonal available shows significant variability.[36]

Current water use for Utah is 904,000 acre-feet annually for municipal and industrial use, while agricultural water use is 4.221 million acre-feet a year.[37] Population estimates have the state doubling its current population of 2,469,585 by 2050.[38] This population increase will not dramatically increase the overall demand of water in the state of Utah because there is also a projected decrease in irrigated lands in some of the fastest growing regions of the state; yet, a decline in irrigated lands is not without its own costs and impacts.[39] The Wasatch Front, for example, is projected to see a 25% decrease in irrigated land in the Weber River basin and a 40% decrease in the Jordan River/ Utah Lake basin by 2050.[40]

Water availability in the future varies on a basin-by-basin basis. Places like the Jordan River and Utah Lake basins are expected to increase demand by 274,000 acre-feet but only have an estimated 50,000 acre-feet available for development. Other areas such as the Upper Colorado River basin (includes West Colorado River, Southeast Colorado River and Uintah basins) have a projected increase in demand of 13,000 acre-feet and a developable supply of 420,000 acre-feet. The West Desert basin, which technically shows a slight surplus in average water years, has such limited availability that it draws into question the long-term operational viability of any large-scale resource development in this region that depends on uninterrupted water availability for its operation. These numbers suggest that as a whole Utah's water situation looks fairly good compared to neighboring states. But, on a basin by basin review, shortages in

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[35] State of Utah Division of Water Resources, Utah's Water Resources Planning for the Future, May 2001

[36] The data presented is an average based on the 1961-1990 period of record. A selection of 6 rivers and creeks from around the state (Logan River, Weber River, Ashley Creek, Beaver River, Sevier River, and Virgin River) show that during the 20th century water supply varied from a low of 62 percent to a max of 138 percent of annual average availability using a composite index.

[37] *Id.*

[38] State of Utah Division of Water Resources, Utah's M&I Water Conservation Plan, July 2003.

[39] State of Utah Division of Water Resources, Utah's Water Resources Planning for the Future, May 2001.

[40] State of Utah natural Resources Division of Water Resources, "Projected Reduction in Irrigated Land by Basin 2000-2050" received April 2006

certain areas and surplus in others will likely led to costly new development projects to ensure the centers of population growth have an adequate supply of water. Additionally when land use conversion occurs water that was formerly used for agriculture may become available for other purposes; however only a portion of the water can legally be transferred, and is dependent upon the prior consumptive use of the irrigated crops.[41]

Estimated Water Surplus/Deficit By Basin *

Basin	Developable Supply (acre-feet/yr)*	Increase in Water Use 2000 to 2050 (acre-feet/yr)	Water Surplus/Deficit (acre-feet/yr)
Upper Colorado River†	420,000	13,000	407,000
Bear River	250,000	11,000	239,000
Jordan River & Utah Lake	50,000	274,000	-224,000
West Desert	25,000	21,000	4,000
Weber River	25,000	106,000	-81,000
Kanab Creek/Virgin River‡	20,000	119,000	-99,000
Sevier River	0	9,000	-9,000
Cedar/Beaver	0	24,000	-24,000
TOTAL	**790,000**	**577,000**	**213,000**

* Values based on the 1961-1990 period of record.

† Includes the West Colorado River, Southeast Colorado River and Uintah basins, and represents Utah's remaining Colorado River Compact depletion allocation.
‡ Does not include Sand Hollow Project, which is under construction.
* Information taken from State of Utah Division of Water Resources, "Utah's Water Resources Planning for the Future," May 2001

Traditionally, water management has focused on supply, ensuring an adequate amount of water to meet demand, ignoring whether or not the water demand was reasonable for the circumstances. In order to address this problem and reduce future water demand, the State has adopted a goal of a 25 percent reduction in the state-wide per capita water use for public community water systems by the year 2050, using the 1995 per capita water use as a baseline.[42] This involves lowering the per capita water use from 321 gallons per capita per day (gpcd) to 241 gpcd by 2050.[43] In calculating the per capita water use numbers, the State includes water use from the residential, commercial, institutional and industrial sectors.

[41] Utah Rivers Council, Bear River Alternatives Analysis, February, 2006.
[42] *Id.*, at 26.
[43] Id., at 27.

Large water users such as energy suppliers play an important role in avoiding an escalation of conflicts over water resources. A host of energy production and cooling types should be considered when planning a new development or expansion of energy supply. In the west, the price of water continues to rise as the demand increases and supplies diminish. Large increases in water use especially in areas with a projected water deficit could have a significant impact on the cost of water, ultimately increasing production costs at power plants. For example, the price of water associated with the Bear River Development Act is $3,091 per acre-foot not including maintenance costs. Conversely, a combination of water conservation and agricultural transfers lowers the cost to $1,745 per acre-foot -- a savings of $1,300 an acre-foot.[44]

In the arid west power producers should consider the negative impacts of total water withdrawals along with consumptive use. In areas of high demand and limited supplies, water shortages (*i.e.* low stream flow, dropping ground water levels due to drought, and high consumption rates) could affect the long-term reliability of water available to perform cooling operations creating operating risks for the facility.

Reducing water use in power production can help the State of Utah achieve its water conservation goals while reducing the liabilities associated with increasing water prices and a variable supply for the power companies. The chart below shows the water use (gal/kwh) for different power production sources as well as cooling systems. Renewable forms of electricity generation use almost no water. Within the category of fossil fuel electricity generation, IGCC generally requires 30-60 percent less water than conventional boilers.[45] And, cooling type reveals a dramatic difference in water use per kilowatt-hour generated.

[44] *Id.*

[45] "Western Coal at the Crossroads," p.10.

Cooling Water Withdrawal and Consumption (gal/kwh) ***

Cooling System	Withdrawal (cooling & processing)	Consumption (cooling)
FOSSIL		
Steam		
Once-through	20-50	~.3
Re-circulating	.3-.8	.24-.64
Dry cooling	~.04	0
Combined Cycle		
Natural gas, once through	7.5-20	~.1
Natural gas, re-circulating	~.23	~.18
Natural gas, dry cooling	~.04	0
Coal, Re-circulating	~.38*	~.2
RENEWABLES		
Wind	~.001	0
Solar-photovoltaic	~.004	0
Solar-parabolic trough	~.83	~.76
Geothermal	**	0-1.0
Biomass		
Steam		
Once-through	23-55	~.35
Re-circulating	.35-.9	.35-.9
Dry cooling	~.05	0

* Includes gasification process water
** If plants require cooling water, it is typically obtained from geothermal heating fluid.

*** Information taken from Clean Air Task Force and Western Resource Advocates, "The Last Straw: Water Use by Power Plants in the Arid West," April 2003; available at http://www.westernresourceadvocates.org/media/pdf/WaterBklet-Final.pdf.

Attachment 2: EPRI Cost Estimates for IGCC and Pulverized Coal Power Plants *

Technology	Coal Type	Total Plant Cost($/kW)	Cost of Energy(¢/kWh)	Efficiency
Supercritical PC[1]	Eastern Bituminous	1,290	4.66	39%
IGCC – GE Energy Radiant Cooling with spare gasifier[2]		1,450	4.90	40%
IGCC – ConocoPhillips E-Gas with spare gasifier[1]		1,350	5.02	39%
IGCC – Shell Gasification with no spare gasifier[2]		1,420	4.20	41%
Subcritical PC[3]	Subbituminous	1,330	4.40	37%
IGCC – ConocoPhillips E-Gas with spare gasifier[3]		1,640	5.40	37%
IGCC – Shell Gasification with no spare gasifier[3]		1,480	4.80	39%

1. George Booras and N. Holt, "Pulverized Coal and IGCC Plant Cost and Performance Estimates," Gasification Technologies 2004, Oct. 3–6, 2004.

2. Neville Holt, "Summary of Recent IGCC Studies of CO_2 Capture for Sequestration," Gasification Technologies 2003, October 14, 2003.

3. Neville Holt, "IGCC Technology Status, Economics and Needs," International Energy Agency Zero Emissions Technologies Workshop, Gold Coast, Queensland, Australia, February 17, 2004.

* Chart taken from Western Resource Advocates, "Western Coal at the Crossroads," p.13; available at http://www.westernresourceadvocates.org/energy/index.php.

Attachment 3: Coal Plant Costs with Carbon Capture *

Study	Technology	Total Capital Cost($/kW)	Cost of Energy (¢/kWh)	Estimated Efficiency
Holt, EPRI, 2005[1]	IGCC (GE Quench)	1,650	6.27	30%[5]
	PC (Ultra-supercritical)	2,150	7.62	29%
Williams, Princeton, 2004[2]	IGCC	1,642	5.71	37%
	PC (Supercritical)	1,981	7.52	29%
Rubin, Carnegie Mellon, 2004[3]	IGCC	1,748	6.26	32%
	PC (Supercritical)	1,936	7.41	30%
David & Herzog, MIT, 2000[4]	IGCC (2012)	1,459	5.14	43%
	PC (2012)	1,718	6.26	36%

1. Presentation by Neville Holt, EPRI Technical Fellow, GCEP Advanced Coal Workshop, Provo, Utah, March 15–16, 2005.

2. R.H. Williams, IGCC: Next Step on the Path to Gasification-Based Energy from Coal, November 2004.

3. Edward S. Rubin, Anand Rao and Chao Chen, Comparative Assessment of Fossil Fuel Power Plants with CO2 Capture and Storage, September 2004.

4. Jeremy David and Howard Herzog, The Cost of Carbon Capture, 2000.

5. NETL/Parsons, Evaluation of Fossil Fuel Power Plants with CO2 Recovery, February 2002.

* Chart taken from Western Resource Advocates, "Western Coal at the Crossroads," p.13; available at http://www.westernresourceadvocates.org/energy/index.php.

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