Office of the Secretary
Service Date
October 6, 2010

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF A REVIEW OF THE SURROGATE AVOIDABLE RESOURCE (SAR) METHODOLOGY FOR CALCULATING PUBLISHED AVOIDED COST RATES	**CASE NO. GNR-E-09-03** **NOTICE OF PUBLIC WORKSHOP** **NOTICE OF COMMENT DEADLINE** **ORDER NO. 32085**

On August 6, 2009, the Idaho Public Utilities Commission (Commission) opened a generic docket (Case No. GNR-E-09-03) to assess the continued viability of the Commission's existing proxy unit or surrogate avoided resource (SAR) methodology for calculating published avoided cost rates. Specifically, the Commission noticed its intent to explore the continued reasonableness of using published avoided cost rates as presently calculated for all Qualifying Cogeneration and Small Power Production Facility (QF) resource types. 18 C.F.R. § 292.101(6).

As reflected in the Commission's August 6, 2009 Notice, the appropriateness of a single avoided cost SAR methodology for published rates is being re-examined in the context of PURPA and FERC requirements[1] and the comparative and different generation and operation capabilities of resources being offered to Idaho utilities, e.g., capacity factor, dispatchability, intermittency. Written comments were solicited. Reply comments were authorized. All comments are available for review at the Commission's office, 472 W. Washington Street, Boise, Idaho and on the Commission's web site www.puc.idaho.gov by clicking on "File Room" and then "Electric Cases."

At the direction of the Commission, Staff prepared a straw man wind SAR proposal earlier this year and distributed it to a small universe of interested parties (QFs and utilities) for their review and comment. See attached proposal. It was a starting point proposal intended to generate discussion of its strengths and weaknesses and to provoke the generation of new and better proposals. Those comments are also available for review at the Commission's offices and

[1] The Public Utility Regulatory Policies Act of 1978 (PURPA) and the implementing regulations of the Federal Energy Regulatory Commission (FERC) (18 C.F.R. § 292).

on its web site. The Commission now finds it reasonable to formally notice the straw man proposal, to schedule a public workshop regarding same and to set a deadline for written comments.

NOTICE OF PUBLIC WORKSHOP

YOU ARE HEREBY NOTIFIED that Commission Staff will hold a public workshop for a discussion of the attached straw man wind SAR proposal on **TUESDAY, OCTOBER 26, 2010, COMMENCING AT 9:30 A.M. AT THE COMMISSION'S HEARING ROOM, 472 W. WASHINGTON STREET, BOISE, IDAHO**. Persons wishing to participate telephonically may dial toll-free **(888) 706-6468; when prompted, enter Participant Code 472404.** The purpose of the workshop is to discuss the strengths and weaknesses of the proposal and to provoke and entertain the generation of new and better proposals.

YOU ARE FURTHER NOTIFIED that the **deadline for filing written comments** regarding the straw man wind SAR proposal is **Tuesday, November 23, 2010**.

YOU ARE FURTHER NOTIFIED that all proceedings in this matter will be held in facilities meeting the accessibility requirements of the Americans with Disabilities Act (ADA). Persons needing the help of a sign language interpreter or other assistance in order to participate in or to understand testimony and argument at a public hearing may ask the Commission to provide a sign language interpreter or other assistance at the hearing. The request for assistance must be received at least five (5) working days before the hearing by contacting the Commission Secretary at:

IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, IDAHO 83720-0074
(208) 334-0338 (Telephone)
(208) 334-3762 (FAX)
E-Mail: secretary@puc.idaho.gov

O R D E R

In consideration of the foregoing and as more particularly described above, IT IS HEREBY ORDERED and the Commission does hereby adopt the foregoing schedule for public workshop and comments in Case No. GNR-E-09-03.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 6th day of October 2010.

JIM D. KEMPTON, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

MACK A. REDFORD, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

bls/O:GNR-E-09-03_sw3

GNR-E-09-03

IN THE MATTER OF A REVIEW OF THE SURROGATE AVOIDABLE RESOURCE (SAR) METHODOLOGY FOR CALCULATING PUBLISHED AVOIDED COST RATES

STAFF'S STRAW MAN PROPOSAL

Staff's straw man proposal is very similar to the spreadsheet currently used to compute rates using a gas-fired CCCT SAR. It requires that a variety of input data be adopted, including identification of reliable data sources and a process for consistent updating. However, in addition to the usual cost and performance assumptions and variables, it also requires consideration of new variables such as tax credits (production tax credits, investment tax credits, sales tax exemptions, loan guarantees, and other financial incentives available to utilities).

AVOIDED COST MODEL FOR WIND

Staff's proposed avoided cost model for wind has been developed using as a starting point the existing model that is used to compute avoided cost rates based on a gas-fired CCCT. Consequently, both models appear fairly similar and use many of the same computational techniques and formulas. The differences between the two models lie primarily in the input data and in the results.

In the gas SAR model, there are basically four cost categories that when added together, make up the total avoided cost rates:

- capital costs,
- fixed O&M costs,
- variable O&M costs, and
- fuel costs.

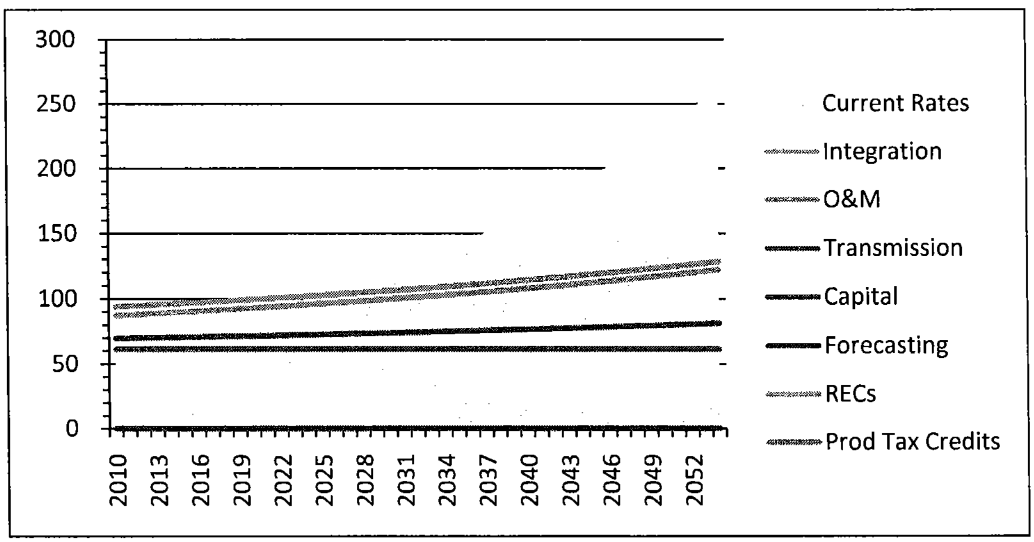
In the wind SAR model, the cost categories are:

- capital costs,
- fixed and variable O&M costs,
- transmission costs,

- tax credits,
- wind integration, and
- forecasting costs.

Just as with the gas CCCT SAR, costs in each category are estimated and escalated over the life of the contract, then added together to develop non-levelized avoided cost rates. From there, the rates are levelized, and adjustments are applied to increase or decrease rates by season and for heavy and light load hours. The figure below illustrates how the various cost components are "stacked" before levelization. In this example, production tax credits are zero (in lieu of a 30% investment tax credit), and no REC premium is assumed.

For comparison purposes, the cost components for the wind SAR have been underlaid with the current rates based on the gas-fired CCCT SAR. Notice that wind SAR rates are higher than gas SAR rates until about the 18th year.



INPUT DATA ASSUMPTIONS

The input data assumptions that have been included in the proposed wind SAR model are shown below. Data have been grouped into seven general categories. Within each category are the data descriptions, the units in which the data must be entered, and the data itself. Data that must be input are shown in blue text. Financial data is shown in black text in the tables below because it is computed on a different worksheet based on each individual utility's cost of capital, capital structure, and tax rates. The only data that is utility-specific is the financial data. The data shown here are proposed values, and are subject to adjustment in the workshop process that is anticipated following the parties' initial review of Staff's straw man proposal.

Input Data		Units	Idaho Power Data
Surrogate Avoided Resource	Plant Cost	$/kW	2,149
	Base Year		2006
	Plant Life	Years	25
	Escalation Rate; Plant Cost	%	1.40%
	Capacity Factor	%	30.0%
	Fixed O&M	$/kW	40.93
	Variable O&M	$/MWh	2.05
	Base Year; O&M		2010
	Escalation Rate; O&M	%	1.90%
Transmission	Transmission Cost	$/kW-mo	1.80
	Base Year		2010
	Escalation Rate; Transmission Cost	%	2.00%
	Transmission Losses	%	1.90%
Production Tax Credits	Production Tax Credit	¢/kWh	2.1
	Base Year		2010
	Escalation Rate; PTC	%	1.9%
RECs	REC Premium	$/MWh	0.00
	Base Year		2010
	Escalation Rate; REC	%	2.70%
Forecasting	Forecasting Cost	$/site	3,500
	Base Year		2010
	Escalation Rate; Forecasting	%	1.90%
Miscellaneous	General inflation rate	%	1.9%
	"Tilting" Rate	%	0.00%
	Current Year		2010
Financial	Utility Weighted Cost of Capital	%	8.180%
	Capital Carrying Charge	%	10.857%
	Level Carrying Cost	$/MWh	61.29

Surrogate Avoided Resource

The surrogate avoided resource data consists of assumptions about the wind surrogate. Unlike the gas surrogate, the wind surrogate does not assume equipment from a specific manufacturer, a specific size, model, or project location. Instead, the wind surrogate is based on generic cost estimates like those routinely used by utilities and planners. Assumptions about a specific project size, equipment type, or configuration are much less critical for a wind SAR because, whether it is a 20 MW PURPA wind project or a 200 MW utility-scale project, they both generally use the same equipment. Although there are undoubtedly some economies of scale, wind project costs are much more linear than costs for gas-fired projects.

Wind SAR data includes the unit cost of wind generation equipment, fixed and variable O&M, and cost escalation rate assumptions about how these unit costs may change in the future. In addition, an assumption must be made about the expected capacity factor of the SAR.

The SAR assumptions primarily determine the capital costs component of the avoided cost rates. In the wind SAR model, capital costs represent, by far, the largest component of the avoided cost rates. Consequently, the avoided cost rates are very sensitive to SAR assumptions, particularly the "plant cost" and "capacity factor" variables. Slight changes in these variables will cause big changes in the avoided cost rates.

Transmission

With the gas CCCT SAR, an assumption has been historically made that the plant would most likely be located very close to a utility's load center, making substantial transmission investment unnecessary. Consequently, no transmission costs have ever been added for the gas CCCT SAR. With a wind SAR, however, it is improbable that a utility scale wind project could be located close to a utility's load center. It is highly likely that any wind project would require some transmission system additions or improvements.

With three multi-jurisdictional utilities, an "avoided" wind resource could be located almost anywhere — in Idaho, Oregon, Washington, Wyoming, or Montana. Transmission costs could vary tremendously depending on a project's size and location. Without an assumed project size or location, it is difficult to make an assumption about transmission costs. For this model, Staff proposes to base transmission costs on the average embedded transmission costs of the three utilities as reported in unbundling reports that were filed with the Commission from 1996 - 2003. Because embedded transmission costs are based on partially depreciated plant that is less costly than new plant, this method may underestimate transmission costs. On the other hand, most wind projects would use as much existing transmission as available and add only as much new transmission improvement as is necessary. Some possible projects might be accommodated entirely using existing transmission.

Another possibility was to use each utility's OATT transmission rate; however, Staff chose not to use an average OATT transmission rate because in theory, these FERC-jurisdictional rates are based on costs associated with wholesale transactions and wheeling, not on transmission costs associated with serving native load customers.

Tax Credits

Tax credits currently play an important role in promoting new wind project development. In most cases, the ownership and financing of new projects is structured in such a way as to take full advantage of available tax credits, whether a project is utility-owned or third-party owned. The availability of various tax credits is usually restricted to projects built before some specified date. The model has been configured to accept production tax credits (PTC) or investment tax credits (ITC), or to apply no tax credits at all. Production tax credits are currently 2.1 cents per kWh, and increase each year based on inflation. PTCs are applied to the first 10 years of production. The federal ITC has been modeled as a 30 percent reduction in the initial cost of the investment (i.e. cash grant). The American Recovery and Reinvestment Act of 2009 (ARRA) allows taxpayers eligible for the PTC to take the ITC or to receive a grant instead of taking the PTC. The 30 percent cash grant assumption produces the lowest avoided cost rates, but the PTC and the "none" options have been included to accommodate possible future expirations or changes in eligibility.

Accelerated depreciation (MACRS) has been used on the capital carrying charge spreadsheet. Under MACRS, wind projects are classified as five-year property and allowed to be depreciated over five years. MACRS has been modeled using a 200% DDB method with a half-year convention.

Bonus depreciation has not been modeled because it expired December 31, 2009 and has not been renewed. State tax incentives (e.g., state investment or production tax credits, sales tax exemptions, property tax incentives, Oregon's Business Energy Tax credit), have also not been modeled, although they could contribute to a project's economics. Parties are invited to make a case for or against including the various tax incentives in the model.

RECs

A wind SAR assumes that the utility owns the project and all attributes associated with it, including its RECs. Consequently, the avoided cost rates computed based on the wind SAR include the RECs regardless of their value. It is not necessary to compute a separate value for RECs because their value is embedded in the cost of wind used to establish the avoided cost rate. In exchange for paying the wind SAR-derived avoided cost rate, the utility receives both the energy and the RECs from the QFs.

The avoided cost model for wind includes a placeholder for RECs, but as configured, a value for RECs would only be entered in the model to reflect a price premium that might be assigned to RECs. If the entire cost and value of RECs is assumed to be captured by the utility simply through the purchase of power from the QF, then the proper REC cost value to be entered in the model is zero.

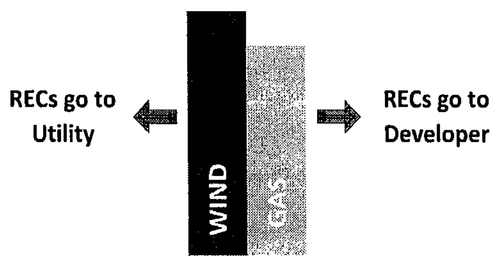
As proposed, there would be two avoided cost models — the existing model based on a gas-fired CCCT and the new model that is based on a wind SAR. Due to likely variations in natural gas price forecasts from time to time, there are two possible scenarios under this proposal — at times the gas SAR rates will be higher than the wind SAR rates; at other times the wind SAR rates will be higher than the gas SAR rates.

When the wind SAR rates are higher, project developers, regardless of their project's technology (i.e., wind, hydro, geothermal, cogeneration, solar, etc.), would be allowed to choose avoided cost rates based on either the gas-fired CCCT SAR or the wind SAR. If the developer chooses rates based on the gas-fired CCCT, then the RECs would be retained by the developer. However, if the developer chooses rates based on the wind SAR, RECs would be turned over to the utility along with the energy generation, at no additional cost to the utility. Developers will have to weigh their expectation of the value of RECs in deciding whether to choose a wind SAR rate that includes utility ownership of RECs versus a gas SAR rate that allows the developer to retain the RECs.

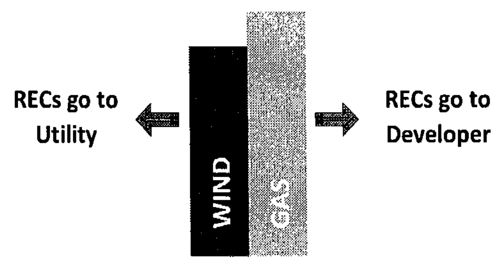
When gas SAR rates are higher, **wind** project developers would **only** be eligible for the wind SAR rates, and consistent with the concept of a wind SAR, the utility would receive the RECs. The logic in support of this position is that it would be unlikely that a utility would be acquiring gas-fired generation to meet energy needs if it was higher cost and did not include REC ownership. In other words, gas generation would not be the avoided resource when gas is more expensive than wind. The utility would be acquiring wind instead.

However, non-wind projects, when gas SAR rates are higher, would be entitled to gas SAR rates and would be permitted to retain ownership of RECs. The reasoning behind this is that non-wind projects provide capacity as well as energy; therefore, a gas SAR is still an appropriate avoided resource.

The illustration below depicts the proposal graphically under a scenario when wind SAR rates are higher and under the reverse scenario when gas SAR rates are higher.



All project types can choose wind SAR rates or gas SAR rates.



Wind projects are <u>only</u> eligible to receive wind SAR rates.

Forecasting

Wind forecasting costs are very minor in comparison to other wind project costs. Nevertheless, they are real, so the model allows for an annual amount to be assumed. Forecasting costs are generally charged for each project site, and are not necessarily proportional to the size of the project. A project size must be assumed, however, in order to spread forecasting costs amongst the energy-based avoided cost rates. For this model, forecasting costs have been assumed to be $3,500 per site per year, with a site being 10 aMW in size.

Miscellaneous

Miscellaneous data include the general inflation rate and the "tilting" rate. The general inflation rate is used as an escalator for some cost components, presumably whenever a more specific escalation rate cannot be determined. The "tilting" rate has been included in the gas-SAR model for many years and has been retained here also. In the past, the tilting rate has been assumed to represent an expected capital cost escalation rate for the SAR.

Financial

The financial data category is shown along with the other input data tables, but the data is actually computed on a different worksheet based on each individual utility's cost of capital, capital structure, and tax rates. Capital costs are computed using the worksheet in the model titled "CapCarChg". This worksheet is nearly identical to the worksheet used in the gas-fired CCCT SAR model, with one exception being that tax depreciation for the wind SAR is based on MACRS with a five year depreciation life.

OTHER MODELING ISSUES

Wind Integration

A wind integration charge is currently applied to the published avoided cost rates for wind QFs. The wind integration charge acts as a discount to reduce the rates paid to wind projects and accounts for the increased cost to the utility of integrating an intermittent resource. Wind integration charges have been established based on studies performed by each utility.

The Commission Staff believes that wind integration charges need to be accounted for in the wind SAR model, just as in the gas SAR model. A utility incurs wind integration charges of the same magnitude whether the resource is an SAR owned by the utility or a wind QF owned by someone else. Unless a wind QF can eliminate or mitigate for the intermittency of its generation, the utility does not "avoid" any wind integration costs because it buys from a wind QF.

In the wind SAR model, wind integration has been modeled the same way it is modeled in the gas SAR. For Idaho Power and Avista, wind integration is modeled as a percentage reduction in the avoided cost rate. The percentage reduction depends on each utility's wind penetration rate, ranging from seven to nine percent. The wind integration charge is capped at $6.50 per MWh. For PacifiCorp, the wind integration charge is $6.50 in all cases.

Dispatchabilty

One of the biggest differences between the current SAR and PURPA QFs is that the SAR is fully dispatchable and PURPA QFs are not (at least none to date have been dispatchable). Dispatchable resources have value for a utility, both because they can be operated whenever needed and because they do not need to be operated when not needed. All dispatchable resources provide some capacity. However, even some non-dispatchable QFs provide some capacity, while other QFs provide none at all. For example, a geothermal QF produces nearly the same amount of generation during all hours throughout the year. A hydro QF on an irrigation system generates a consistent, predictable amount during irrigation season. Wind QFs, on the other hand, provide little or no capacity because their generation is intermittent and unpredictable.

A project must provide capacity in order to be dispatchable. The value of capacity depends on when it is provided. Capacity provided during peak hours, days or seasons has substantially more value than capacity provided at other times. There may be times when providing capacity has no value. Consequently, higher capacity factors do not always necessarily mean higher value. Moreover, the value of capacity will vary over the life of the project depending on the utility's capacity position.

The difference between different QF resources' and an SAR's dispatchabilty and abilty to provide capacity has never been accounted for in Idaho's avoided cost methodologies. While it may be more necessary now than ever before, to do so could be difficult, especially now that there has become a much wider diversity of QF resource types with characteristics quite different from a gas-fired CCCT SAR.

However, if a wind SAR were adopted for purposes of computing avoided cost rates – at least for wind QFs – assigning a value to capacity or dispatchability would not be necessary. As long as the SAR used to compute rates has the same characteristics as the QF resources for which the rates are being set, there is no need for adjustments to account for differences.

Emission Adders, Fuel Risk Adders

Nothing in the current SAR methodology recognizes the value of reducing fossil fuel use (e.g., reduction in CO_2 taxes, value of SO_2 credits), benefits that a QF may provide that would not be provided by a gas-fired CCCT. If a QF causes some fossil-fueled resource to be deferred, displaced, or operated less, and thus have lower emission costs, it currently receives no credit for it. As emission costs begin to be imposed on fossil-fueled facilities, it could be argued that credit for the emission reductions attributable to QFs is warranted.

Similarly, some QFs, wind in particular, have no fuel costs. Therefore, unlike a gas-fired CCCT SAR, wind presents no fuel cost risk. It could be argued that QFs with no fuel cost risk deserve credit for this benefit also.

If a wind SAR were adopted, the questions of emission adders and fuel risk adders to published avoided cost rates become moot. One reason utilities' IRPs include wind resources in their preferred portfolios is because of the absence of emission costs and fuel price risk. As long as utilities continue to plan to acquire wind resources outside of PURPA, it is reasonable to assume for purposes of avoided cost rates that wind is truly an "avoided resource." Thus, adoption of a wind SAR will permit the Commission to steer clear of addressing the thorny issue likely to arise in the future of emission adders and fuel risk adders.

SOURCES FOR INPUT DATA

There are several possible sources for input data related to wind costs. Each utility, in its IRP, makes cost assumptions for new wind generation. In addition, the Northwest Power and Conservation Council (NPCC) makes similar cost assumptions in preparing its power plans. The U.S. Department of Energy, Energy Information Administration includes wind cost assumptions in its Annual Energy Outlook, a report published annually each spring.

Cost data from the NPCC has been used for the gas SAR model. Although the data have been considered accurate and impartial, parties in other proceedings before the Commission have expressed frustration that the data are not updated regularly. In addition, the Council staff have expressed some discomfort in being relied upon as a source for data that is directly used to establish rates. Council staff do not wish to be lobbied to adopt higher or lower cost data, since it views its role as planning, not ratesetting.

Table 1 is a summary of wind cost data from various sources. As shown, the data were compiled in various different years and are expressed in different year's dollars. Table 2 shows the same data adjusted to be in 2010 dollars. If necessary, the Commission Staff proposes that parties in this case negotiate in a workshop process to agree upon acceptable sources for input data.

UPDATES TO INPUT DATA ASSUMPTIONS

Whatever data source is chosen for the input cost data, it will be necessary to periodically update the assumptions. The Commission Staff proposes to update the avoided cost computations whenever the source data are updated.

Adjustments to Avoided Cost Rates Computed Based with a Wind SAR

Even if a wind SAR is adopted, there are still some adjustments made to avoided cost rates that Staff believes need to be retained. "Seasonalization" is an adjustment made to recognize changes in the value of power throughout the year. In seasons when power is normally plentiful and less expensive, in the spring for example, a seasonalization factor less than one is applied to reduce avoided cost rates. In other seasons when power is more expensive, such as in the summer and winter, a seasonalization factor greater than one is applied to increase avoided cost rates.

A daily load shape adjustment recognizes differences in power value between heavy and light load hours. The adjustment increases avoided cost rates for power delivered in heavy load hours and decreases rates for power delivered in light load hours. Staff believes this adjustment is still appropriate for all QF generation technologies, regardless of what type of SAR is used to compute avoided cost rates.

In addition to retaining seasonal and daily load shape adjustments, Staff also believes that the current requirement for a mechanical availability guarantee (MAG) should be retained. MAG requirements for wind projects recognize reliability by requiring that project facilities are mechanically available to operate whenever there is sufficient wind.

Fuel Price Risk and Dispatchability

As currently constructed, neither the gas SAR model nor the wind SAR model attempts to account for fuel price risk. Obviously, gas-fired resources are exposed to considerable price risk, while wind generation has little or no direct "fuel" price risk. Similarly, dispatchability is not accounted for in either SAR model. A gas-fired CCCT is dispatchable, a wind project is not. Fuel price risk and dispatchability would be difficult to account for in an SAR model. The fact that fuel price risk works in favor of a wind project, but dispatchability works against it are offsettting factors that help to minimize the impact of not including either in the SAR models.

THE RESULTS

The avoided cost rates computed using the wind SAR are shown on the attached tables. Note that these are the results using sample sets of input data. It is highly probable that some of the input data will be modified during the course of workshops. Nevertheless, the rates shown in the attached tables are within a likely range of results.

Using the sample data shown on page 12, a 20-year levelized wind rate with a 2010 online date is as follows for each utility for both a wind and a gas SAR:

Utility	Wind SAR	Gas SAR
Avista	$86.31/MWh	$79.17/MWh
Idaho Power	$84.72/MWh	$79.19/MWh
PacifiCorp	$85.06/MWh	$79.31/MWh

The Wind SAR rates shown above assume that the utility will own the RECs associated with all power purchased from each project. The Gas SAR rates assume that the project developer owns the RECs. Although not explicit in the computations, it could be implied from these rates, that the approximate 20-year levelized value of RECs is between $5.50 and $7.10.

Table 1. Summary of Wind Cost Assumptions

				PacifiCorp IRP			DOE/EIA
	Cost in Year	Avista IRP	Idaho Power IRP	East	West	NPCC 6th Plan	2010 AEO
		2009	2009	2008	2008	2008	2009
	Year$	2009$	2009$	2008$	2008$	2006$	2008$
Overnight Capital Cost	$/kW		1,275			2,100	1,966
Overnight Transmission Capital	$/kW		503				
AFUDC	$/kW		111				
Total Investment	$/kW	2,183	1,887	2,566	2,612		
Plant Life	years		30	25	25		
Transmission Costs	$/kW-yr	18.00				17.15	
Transmission Losses	%	1.90%				1.90%	
Fixed O&M	$/kW	45.00	35.00	31.43	31.43	40.00	30.98
Variable O&M	$/MWh		1.00			2.00	0.00
O&M Escalation Rate	%		3.00%				
Capacity Factor	%	30%	32%	35%	29%	30%	
Wind Integration Charge	$/MWh	4.05		11.75	11.75	11.43	
Production Tax Credit Esc Rate			3.00%				
General O&M Esc Rate			3.00%				

Table 2. Summary of Adjusted Wind Cost Assumptions

				PacifiCorp IRP				
	Cost in Year Year$	Avista IRP 2010 2010$	Idaho Power IRP 2010 2010$	East 2010 2010$	West 2010 2010$	NPCC 6th Plan 2010 2010$	DOE/EIA 2010 AEO 2010 2010$	Avg
Overnight Capital Cost	$/kW		1,304			2,149	1,961	1,804
Overnight Transmission Capital	$/kW		514					
AFUDC	$/kW		113					
Total Investment	$/kW	2,232	1,929	2,559	2,605			2,331
Plant Life	years		30	25	25			
Transmission Costs	$/kW-yr	18.40				17.55		17.98
Transmission Losses	%	1.90%				1.90%		
Fixed O&M	$/kW	46.01	35.79	31.35	31.35	40.93	30.90	36.05
Variable O&M	$/MWh		1.02			2.05	0.00	1.02
O&M Escalation Rate	%		3.00%					
Capacity Factor	%	30%	32%	35%	29%	30%		31.2%
Wind Integration Charge	$/MWh	4.14		11.72	11.72	11.69		9.82
Production Tax Credit Esc Rate			3.00%					
General O&M Esc Rate			3.00%					

AVISTA
AVOIDED COST RATES FOR WIND PROJECTS SMALLER THAN 10 aMW
WITHOUT RECS
DRAFT
$/MWh

LEVELIZED							**NON-LEVELIZED**	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2010	2011	2012	2013	2014	2015		
1	82.66	83.13	83.61	84.09	84.59	85.09	2010	82.66
2	82.88	83.36	83.84	84.33	84.83	85.34	2011	83.13
3	83.11	83.58	84.07	84.56	85.07	85.58	2012	83.61
4	83.32	83.80	84.29	84.79	85.30	85.83	2013	84.09
5	83.54	84.02	84.51	85.02	85.54	86.07	2014	84.59
6	83.75	84.23	84.73	85.24	85.77	86.31	2015	85.09
7	83.95	84.44	84.95	85.47	86.00	86.55	2016	85.61
8	84.15	84.65	85.16	85.69	86.23	86.79	2017	86.13
9	84.35	84.86	85.38	85.91	86.46	87.02	2018	86.69
10	84.55	85.06	85.58	86.12	86.68	87.24	2019	87.28
11	84.74	85.26	85.79	86.33	86.89	87.47	2020	87.87
12	84.93	85.45	85.99	86.54	87.10	87.68	2021	88.48
13	85.12	85.65	86.19	86.74	87.31	87.89	2022	89.11
14	85.30	85.84	86.38	86.94	87.51	88.10	2023	89.74
15	85.48	86.02	86.57	87.13	87.71	88.30	2024	90.38
16	85.66	86.20	86.75	87.32	87.90	88.50	2025	91.04
17	85.83	86.37	86.93	87.50	88.09	88.69	2026	91.71
18	85.99	86.54	87.10	87.68	88.27	88.87	2027	92.40
19	86.16	86.71	87.27	87.85	88.45	89.05	2028	93.09
20	86.31	86.87	87.44	88.02	88.62	89.23	2029	93.80
							2030	94.53
							2031	95.26
							2032	96.02
							2033	96.78
							2034	97.56
							2035	98.36

IDAHO POWER COMPANY
AVOIDED COST RATES FOR WIND PROJECTS SMALLER THAN 10 aMW
WITHOUT RECS
DRAFT
$/MWh

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2010	2011	2012	2013	2014	2015		
1	80.83	81.33	81.85	82.37	82.90	83.44	2010	80.83
2	81.07	81.58	82.10	82.62	83.16	83.71	2011	81.33
3	81.31	81.82	82.34	82.88	83.42	83.97	2012	81.85
4	81.54	82.06	82.59	83.12	83.67	84.23	2013	82.37
5	81.77	82.30	82.83	83.37	83.92	84.48	2014	82.90
6	82.00	82.53	83.06	83.61	84.17	84.73	2015	83.44
7	82.22	82.75	83.29	83.84	84.41	84.98	2016	84.00
8	82.44	82.98	83.52	84.08	84.64	85.22	2017	84.56
9	82.66	83.19	83.74	84.30	84.87	85.45	2018	85.14
10	82.87	83.41	83.96	84.53	85.10	85.69	2019	85.72
11	83.07	83.62	84.18	84.74	85.32	85.91	2020	86.32
12	83.27	83.82	84.38	84.96	85.54	86.13	2021	86.93
13	83.47	84.02	84.59	85.16	85.75	86.35	2022	87.55
14	83.66	84.22	84.79	85.37	85.96	86.56	2023	88.19
15	83.85	84.41	84.98	85.57	86.16	86.77	2024	88.83
16	84.03	84.60	85.17	85.76	86.36	86.97	2025	89.49
17	84.21	84.78	85.36	85.95	86.55	87.17	2026	90.16
18	84.39	84.96	85.54	86.13	86.74	87.36	2027	90.84
19	84.55	85.13	85.72	86.31	86.92	87.54	2028	91.54
20	84.72	85.30	85.89	86.49	87.10	87.73	2029	92.25
							2030	92.97
							2031	93.71
							2032	94.46
							2033	95.23
							2034	96.01
							2035	96.81

PACIFICORP
AVOIDED COST RATES FOR WIND PROJECTS SMALLER THAN 10 aMW
WITHOUT RECS
DRAFT
$/MWh

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2010	2011	2012	2013	2014	2015		
1	81.18	81.69	82.20	82.72	83.26	83.80	2010	81.18
2	81.43	81.93	82.45	82.98	83.52	84.06	2011	81.69
3	81.66	82.18	82.70	83.23	83.77	84.33	2012	82.20
4	81.90	82.41	82.94	83.48	84.03	84.58	2013	82.72
5	82.13	82.65	83.18	83.72	84.27	84.84	2014	83.26
6	82.35	82.88	83.42	83.96	84.52	85.09	2015	83.80
7	82.58	83.11	83.65	84.20	84.76	85.33	2016	84.35
8	82.79	83.33	83.87	84.43	84.99	85.57	2017	84.92
9	83.01	83.55	84.10	84.65	85.23	85.81	2018	85.49
10	83.22	83.76	84.31	84.88	85.45	86.04	2019	86.08
11	83.42	83.97	84.53	85.09	85.67	86.26	2020	86.68
12	83.62	84.17	84.73	85.31	85.89	86.48	2021	87.29
13	83.82	84.37	84.94	85.51	86.10	86.70	2022	87.91
14	84.01	84.57	85.14	85.72	86.31	86.91	2023	88.54
15	84.20	84.76	85.33	85.91	86.51	87.11	2024	89.19
16	84.38	84.94	85.52	86.11	86.70	87.31	2025	89.84
17	84.56	85.12	85.70	86.29	86.90	87.51	2026	90.51
18	84.73	85.30	85.88	86.48	87.08	87.70	2027	91.20
19	84.90	85.47	86.06	86.66	87.26	87.88	2028	91.89
20	85.06	85.64	86.23	86.83	87.44	88.06	2029	92.60
							2030	93.33
							2031	94.07
							2032	94.82
							2033	95.59
							2034	96.37
							2035	97.16

	B	C	D	E
34	Input Data		Units	Idaho Power Data
35				
36	Surrogate Avoided Resource	Plant Cost	$/kW	2,149
37		Base Year		2006
38		Plant Life	Years	25
39		Escalation Rate; Plant Cost	%	1.40%
40		Capacity Factor	%	30.0%
41		Fixed O&M	$/kW	40.93
42		Variable O&M	$/MWh	2.05
43		Base Year; O&M		2010
44		Escalation Rate; O&M	%	1.90%
45				
46	Transmission	Transmission Cost	$/kW-mo	1.80
47		Base Year		2010
48		Escalation Rate; Transmission Cost	%	2.00%
49		Transmission Losses	%	1.90%
50				
51	Production Tax Credits	Production Tax Credit	¢/kWh	2.1
52		Base Year		2010
53		Escalation Rate; PTC	%	1.90%
54				
55	RECs	REC Premium	$/MWh	0.00
56		Base Year		2010
57		Escalation Rate; REC	%	2.70%
58				
59	Forecasting	Forecasting Cost	$/site	3,500
60		Base Year		2010
61		Escalation Rate; Forecasting	%	1.90%
62				
63	Miscellaneous	General Inflation rate	%	1.9%
64		"Tilting" Rate	%	0.00%
65		Current Year		2010
66				