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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE COMMISSION'S REVIEW OF PURPA QF CONTRACT PROVISIONS INCLUDING THE SURROGATE AVOIDED RESOURCE (SAR) AND INTEGRATED RESOURCE PLANNING (IRP) METHODOLOGIES FOR CALCULATING AVOIDED COST RATES.	**CASE NO. GNR-E-11-03** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Kristine A. Sasser, Deputy Attorney General, and in response to Order No. 32737, submits the following comments.

BACKGROUND

On February 5, 2013 the Commission issued Order No. 32737 in Case No. GNR-E-11-03. In part, that Order granted the Petitions for Clarification of Renewable Energy Coalition and Idaho Power regarding the definition of "canal drop hydro" and the determination of resource-specific capacity factors as they relate to "canal drop hydro" and "other" projects under the SAR methodology. Because the issues surrounding the definition of canal drop hydro and resource-specific capacity factors were not fully explored at hearing, the Commission directed the parties to file comments on these issues.

A proper definition of "canal drop hydro" is important because under the Surrogate Avoided Resource ("SAR") methodology "hydro" and "canal drop hydro" are distinguishable, each with its own set of published avoided cost rates. "Canal drop hydro" has a higher set of avoided cost rates because irrigation-related projects provide capacity when the utility most needs it – during the peak hours of the peak days of the year (i.e., during the summer season). The definition of "canal drop hydro" will dictate which hydro projects are entitled to the higher published avoided cost rates.

Resource-specific capacity factors are used in the SAR model for two different purposes. First, the *on-peak* capacity factors of each resource type are used in determining the value of the capacity provided by each resource towards helping to meet the utility's summer and winter peak. For example, resources that can provide capacity during a utility's peak load hours have much greater value to the utility than resources that do not generate on-peak. Higher peak capacity factors in the SAR model generate <u>higher</u> rates.

Second, *annual* capacity factors are used in the SAR model for the purpose of spreading capacity value over the kilowatt-hours of generation produced by the project. In actuality, capacity value is dependent only on the peak hour timing of a project's generation, not on the volume of its energy generation over the course of the year. However, because avoided cost payments are made only as a per kilowatt-hour payment (energy), capacity payments (capacity) must be spread over an estimated number of kilowatt hours in order for the project to be fully reimbursed for its capacity value. Higher annual capacity factors in the SAR model generate <u>lower</u> rates.

The "other" category of published rates is intended for all project types other than hydro, "canal drop hydro," wind, and solar. This would typically encompass project types such as biomass (wood or agricultural waste), biogas (municipal wastewater treatment, animal waste), landfill gas, and geothermal. These project types operate more like baseload facilities, and have similar capacity factors.

ANALYSIS

Definition of seasonal hydro project

Instead of using the term "canal drop hydro," Staff proposes using the term "seasonal hydro." What is important, Staff believes, is not whether a hydro project is located on a canal or whether it is somehow associated with irrigation, but instead whether it reliably generates during the season of the year when capacity is most valuable to the utility, i.e., summer for Idaho Power and PacifiCorp.

Staff proposes to define a seasonal hydro project as one that, over the last ten years, generated at least 90 percent of its average annual generation during the months of April through October. There currently are 26 hydro projects on Idaho Power's system that meet this definition and 33 hydro projects which do not meet this definition. Ninety-percent was chosen as the cut-off point because there appeared to be a natural break in the data at this point.

This definition would apply to any new hydro project seeking a contract and to any existing projects seeking to replace an expiring contract. For new contracts, Staff proposes that projects be required to demonstrate compliance with this definition in the first year of operation, with retroactive adjustment of rates if the project fails to comply.

Because Staff proposes to use capacity factor as a means of defining seasonal and non-seasonal hydro projects, each resulting category will by definition exhibit its own characteristics for both annual and peak hourly capacity factor. Adding or removing projects from one category to the other will unavoidably impact the overall capacity factor characteristics of the other category. Consequently, it will be necessary for Staff to propose annual and peak capacity factors for each category, even though Order No. 32737 seeks comments only on "capacity factors as they relate to 'canal drop hydro' and 'other' projects under the SAR methodology."

Annual capacity factors

Using monthly generation data provided by Idaho Power, Staff calculated an average annual capacity factor for two groups of projects: seasonal hydro projects and non-seasonal hydro projects. These, along with the peak capacity factors, are shown in the table below.

	Annual capacity factor	Peak hour capacity factors	
		Summer peak	Winter peak
Seasonal hydro projects	32%	79%	0%
Non-seasonal hydro projects	50%	67%	25%
"Other" projects	89%	93%	93%

Peak hour capacity factors

In the direct testimony of Mark Stokes, Idaho Power outlined its methodology for determining peak capacity factors. To summarize, Idaho Power examined the output of four different hydro projects during the hours of 3 p.m. through 7 p.m. in July. For each of these hours, Idaho Power calculated a capacity factor by summing the actual output from these projects and then dividing this by the sum of the nameplate capacity of the same projects. This resulted in a capacity factor for each peak hour of each year.

Idaho Power used these hourly capacity factors to compute an annual capacity factor for each year. Idaho Power defined the annual capacity factor as the hourly capacity factor that would be exceeded 90 percent of the time. Idaho Power calls this the 90th percentile capacity factor. Idaho Power averaged this annual 90th percentile capacity factor over all the years with data to arrive at the summertime peak capacity factor. Attachment 1 illustrates Idaho Power's approach.

Staff made several changes to Idaho Power's approach as listed below:

1. Staff defined summer peak hours as the hours between 3 p.m. and 8 p.m. from June 23 through July 31. Staff defined winter peak hours as 8 a.m. and 9 a.m. from December 1 through February 28/29.
2. Staff used MV90 hourly generation data instead of PI data.[1]
3. Staff applied a correction factor to the sample of projects that had hourly data available in order to make this sample more representative of the total population of projects.

It should be noted that Staff agrees with Idaho Power that the 90th percentile capacity factor is appropriate to use. It is consistent with Idaho Power's IRP as Idaho Power uses 90th percentile water conditions for peak hour capacity planning in their IRP. Using a lower percentile capacity factor increases the probability that planned-on capacity will not be available when needed. Staff believes that the 90th percentile capacity factor minimizes this risk. If, instead, a 50th percentile capacity factor (the median) was used, then half of the time, planned-on capacity would not actually be available during peak hours.

[1] Idaho Power provided two different types of hourly generation data: MV90 data (measured in kilowatts) and PI data (measured in megawatts).

Staff determination of peak hours

Staff used 20 years of data from Idaho Power's annual FERC Form 1 filings to identify the day and hour of Idaho Power's summer and winter peak for those 20 years. The years included are 1991-1997 and 1999-2011. Staff does not have a copy of the 1998 filing and the 2012 filing has not yet been made.

Attachment 2 graphically shows the time of day and date that the summer peak occurred for this time period. As can be seen, the summer peak occurred between the hours of 3 p.m. through 8 p.m. from June 23rd through July 29th. Thus, Staff defined peak hours as those hours between 3 p.m. and 8 p.m. between June 23rd and July 31st. In comparison to Idaho Power's definition of peak hours, Staff's definition of peak hours includes an additional 8 days (June 23rd through June 30th) and an additional hour (8 p.m.).

Attachment 3 graphically shows the time of day and date that the winter peak occurred for this time period. The winter peak occurred anywhere from the first part of December to the last part of February. While there was variation in the month of the winter peak, there was little variation in the hour of the winter peak. The winter peak occurred at either 8 a.m. or 9 a.m. for all years except one in which it occurred at 7 p.m. Staff views the 7 p.m. peak as an anomaly and, therefore, defined winter peak hours as 8 a.m. and 9 a.m. during the months of December, January, and February.

Data sources

Idaho Power provided two different types of hourly generation data in response to Staff's Fourth Production Request, Request No. 22: MV90 data (measured in kilowatts) and PI data (measured in megawatts). Hourly generation data was available from 2006 through 2012. In 2012, Idaho Power had 59 hydro projects in the state of Idaho. Out of these 59 projects, nine projects had MV90 data and four had PI data.

Staff found several inconsistencies in the PI data provided by Idaho Power. Furthermore, as noted by Idaho Power in their response to Staff's Request No. 22, the PI data is inherently less precise than the MV90 data because the PI data is measured at the MW level while the MV90 data is measured at the kW level.[2] Due to the inconsistencies and lack of precision in the PI data, Staff decided to only use the MV90 data in its peak capacity calculations.

This approach differs from Idaho Power's approach. Idaho Power used PI data for four canal drop hydro projects to calculate its peak capacity factor. In addition, Idaho Power calculated its peak capacity factors using four years of data (2008 through 2011) while Staff used six years of data (2007-2012).

Representativeness of sample

As noted above, Staff defined the population of seasonal hydro projects as those hydro projects which had 90 percent of their generation occur during the months of April through October. Using the monthly generation data provided by Idaho Power, Staff found that 26 hydro projects met that definition. These 26 hydro projects comprise the population of seasonal hydro projects. Of the nine hydro projects with hourly MV90 data, seven are seasonal hydro projects. Those seven comprise the sample of seasonal hydro projects.

Staff had concerns that the sample of projects did not accurately represent the population of projects. Staff examined this issue by comparing the July monthly capacity factor for projects in the sample with the population of projects. Staff found that the July capacity factor was lower for projects included in the sample (71 percent) than for the population as a whole (78 percent). Therefore, a capacity factor calculated using only this sample would most likely be biased by underestimating the actual peak capacity contribution of the population. Furthermore, as the composition of projects included in the sample changed over time, this bias was likely worse for the early years of data.

In order to correct this potential bias, Staff took two steps. First, Staff used linear regression techniques to estimate the annual 90th percentile capacity factor for each project as if it had been operational throughout the entire time period. In other words, Staff estimated capacity factors for each year from 2007 through 2012 for each project in the sample. This step should account for changing sample composition during the time period. Second, Staff compared the average monthly July capacity factor of this sample to the average monthly July capacity factor of the population for the 2007-2012 time period (both averages were weighted by project nameplate capacity). Staff calculated the percentage difference between these two factors and called this the

[2] Hourly PI data is less precise than hourly MV90 data because PI data is used for scheduling purposes where less accuracy is required, whereas MV90 data is used for billing purposes where great accuracy is required.

sample correction factor. Staff then applied this sample correction factor to the average annual 90^{th} percentile capacity factor calculated using the regression results. This resulted in a summertime peak capacity factor for seasonal hydro projects of 79 percent. Staff did a similar analysis for non-seasonal hydro projects and calculated a summertime peak capacity factor of 67 percent.

Bias could also exist in the calculation of the wintertime peak capacity factor. In order to examine the issue of bias in the wintertime, Staff repeated the same analysis except using winter months in its calculation and comparing the results to the average of the December, January, and February monthly capacity factors. Staff used the wintertime peak capacity hours to define the peak period as described above. Staff calculated a wintertime peak capacity factor of 0 percent for seasonal hydro projects and 25 percent for non-seasonal hydro projects.

Capacity factors for "other" project types

As mentioned earlier, "other" project types include biomass (wood or agricultural waste), biogas (municipal wastewater treatment, animal waste), landfill gas, and geothermal. These project types operate more like baseload facilities, and have similar capacity factors.

Staff proposes that the Northwest Power and Conservation Council's Sixth Power Plan be used as the basis for capacity factors for projects in the "other" category. Appendix I of the Sixth Power Plan contains discussion of the generation characteristics and planning assumptions for a wide variety of generation resources, including each of those likely to fall in the "other" project category.

Attachment 4 is a summary of the Council's planning assumptions for Equivalent Forced Outage Rates and for Equivalent Annual Availabilities for relevant project types. Equivalent Forced Outage Rate (EFOR) is the hours of unit failure (unplanned outage hours and equivalent unplanned derated hours) given as a percentage of the total hours of the availability of that unit (unplanned outage, unplanned derated, and service hours). Equivalent Annual Availability (EAA) represents the amount of time that a plant is able to produce electricity in a year, divided by the amount of the time in the year. Occasions where only partial capacity is available are deducted. In other words, EFOR represents the percentage of time forced outages occur, while EAA represents the percentage of time the plant is available taking into consideration both forced and unforced outages.

Staff proposes an *annual* capacity factor of 89 percent for "other" project types based on the average EAA for the project types shown on Attachment 4. Staff believes it is more appropriate to base the annual capacity factor on EAA because it represents the percentage of time a project would be expected to operate during the year, accounting for both forced and unforced outages.

Staff proposes that a *peak* capacity factor of 93 percent be used for "other" project types based on the average EFOR for the project types shown on Attachment 4.[3] Because the generation from "other" project types generally does not vary substantially by season, Staff proposes that the same capacity factor be used for both summer and winter. Staff believes it is more appropriate to base the peak capacity factor on the EFOR because it only accounts for the periods of time when forced outages occur. Because projects can control when unforced outages occur, it is unlikely a project would choose to have an outage during the utility's peak load period. Staff proposes a rounded number be used for simplicity and in recognition that the numbers upon which it is based are not precise.

Avoided cost rates using Staff's proposed capacity factors

Using Staff's proposed capacity factors in the SAR model, Staff computed the resulting avoided cost rates for seasonal hydro, non-seasonal hydro and other project types. The resulting rates are shown in Attachment 5 for each utility. Compared to the rates currently in effect, the rates for seasonal hydro are almost equivalent to the rates for "canal drop hydro." This is due to the fact that the <u>increase</u> in rates due to changing the annual capacity factor almost completely offset the <u>decrease</u> in rates due to changing the peak summer capacity factor.[4] Specifically, the proposed rates for a 20-year seasonal hydro project online in 2013 are roughly a half percent lower than the current rates for a canal drop hydro project for all three utilities.

Compared to the current rates, the proposed rates for a 20-year non-seasonal hydro project online in 2013 are approximately 23 percent higher for Idaho Power and 24 percent higher for PacifiCorp. These large increases are driven by the increase in the summer peak capacity factor. The current summer peak capacity factor is 25 percent while the proposed summer peak capacity factor is 67 percent. The increase for Avista is 6 percent. This is due to the fact that Avista

[3] To be more precise, Staff's proposal is based on (1 - EFOR), which represents the percentage of time the project would be operational, rather than the time it would not be operational due to forced outages.
[4] The annual capacity factor decreased by 20% (40% to 32%) leading to an increase in rates. The peak summer capacity factor decreased by 21% (100% to 79%) leading to a decrease in rates.

switches from needing capacity in the summer to needing capacity in the winter and, while the summer peak capacity factor increased from the current factor, the winter peak capacity factor decreased from the current factor (50 percent to 25 percent). Finally, the proposed rates for a 20-year "other" project type online in 2013 is 2 to 4 percent lower than the current rates for all the utilities.

RECOMMENDATIONS

First, Staff recommends that the terminology "seasonal hydro project" be used in the future instead of "canal hydro" to refer to hydro projects whose generation is primarily produced in the summer months. Staff recommends that a seasonal hydro project be defined as one that generates at least 90 percent of its annual generation during the months of April through October. Seasonal hydro projects should qualify for higher published avoided cost rates than non-seasonal projects.

Second, Staff recommends that the following annual and peak capacity factors be used for seasonal hydro, non-seasonal hydro, and "other" project types:

	Annual capacity factor	Peak hour capacity factors	
		Summer peak	Winter peak
Seasonal hydro projects	32%	79%	0%
Non-seasonal hydro projects	50%	67%	25%
"Other" projects	89%	93%	93%

Dated at Boise, Idaho, this 25TH day of March 2013.

Kristine A. Sasser

Kristine A. Sasser
Deputy Attorney General

Technical Staff: Cathleen McHugh
Rick Sterling

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Attachment 1: Illustration of Idaho Power's methodology in calculating summer peak capacity factors

Note: All of the numbers used are for illustration purposes only. They do not reflect any actual project on Idaho Power's system.

1. Calculate total nameplate capacity of all the projects

	Project A (a)	Project B (b)	Project C (c)	Project D (d)	**Total nameplate capacity (e)=(a)+(b)+(c)+(d)**
Nameplate capacity (kW)	100	500	50	150	**800**

2. Calculate the capacity factor across all projects for each hour

Year 1	Project A (f)	Project B (g)	Project C (h)	Project D (i)	Total output (j)=(f)+(g)+(h)+(i)	**Capacity Factor (k)=(j)/(e)**
July 1 - 3 p.m.	96	380	22	107	605	**75.6%**
July 1 - 4 p.m.	93	366	27	110	596	**74.5%**
July 1 - 5 p.m.	93	440	27	107	667	**83.4%**
July 1 - 6 p.m.	93	371	20	101	585	**73.1%**
July 1 - 7 p.m.	95	382	21	95	593	**74.1%**
July 2 - 3 p.m.	98	383	20	103	604	**75.5%**
July 2 - 4 p.m.	99	392	20	100	611	**76.4%**
July 2 - 5 p.m.	94	365	22	102	583	**72.9%**
July 2 - 6 p.m.	91	363	23	92	569	**71.1%**
July 2 - 7 p.m.	92	360	24	116	592	**74.0%**
July 3 - 3 p.m.	95	375	24	98	592	**74.0%**
Year 2						
July 1 - 3 p.m.	95	377	22	99	593	**74.1%**
July 1 - 4 p.m.	92	382	28	110	612	**76.5%**
July 1 - 5 p.m.	96	384	22	110	612	**76.5%**
July 1 - 6 p.m.	98	428	23	103	652	**81.5%**
July 1 - 7 p.m.	94	426	24	114	658	**82.3%**
July 2 - 3 p.m.	98	438	23	103	662	**82.8%**
July 2 - 4 p.m.	96	449	21	92	658	**82.3%**
July 2 - 5 p.m.	94	417	26	120	657	**82.1%**
July 2 - 6 p.m.	100	433	20	112	665	**83.1%**
July 2 - 7 p.m.	94	359	22	95	570	**71.3%**
July 3 - 3 p.m.	93	400	24	98	615	**76.9%**

3. Calculate the 90th percentile capacity factor.
    a. Sort the capacity factors for each year in order of largest to smallest.

Year 1			Year 2	
July 1 - 5 p.m.	83.4%		July 2 - 6 p.m.	83.1%
July 2 - 4 p.m.	76.4%		July 2 - 3 p.m.	82.8%
July 1 - 3 p.m.	75.6%		July 1 - 7 p.m.	82.3%
July 2 - 3 p.m.	75.5%		July 2 - 4 p.m.	82.3%
July 1 - 4 p.m.	74.5%		July 2 - 5 p.m.	82.1%
July 1 - 7 p.m.	74.1%		July 1 - 6 p.m.	81.5%
July 2 - 7 p.m.	74.0%		July 3 - 3 p.m.	76.9%
July 3 - 3 p.m.	74.0%		July 1 - 4 p.m.	76.5%
July 1 - 6 p.m.	73.1%		July 1 - 5 p.m.	76.5%
July 2 - 5 p.m.	72.9%		July 1 - 3 p.m.	74.1%
July 2 - 6 p.m.	71.1%		July 2 - 7 p.m.	71.3%

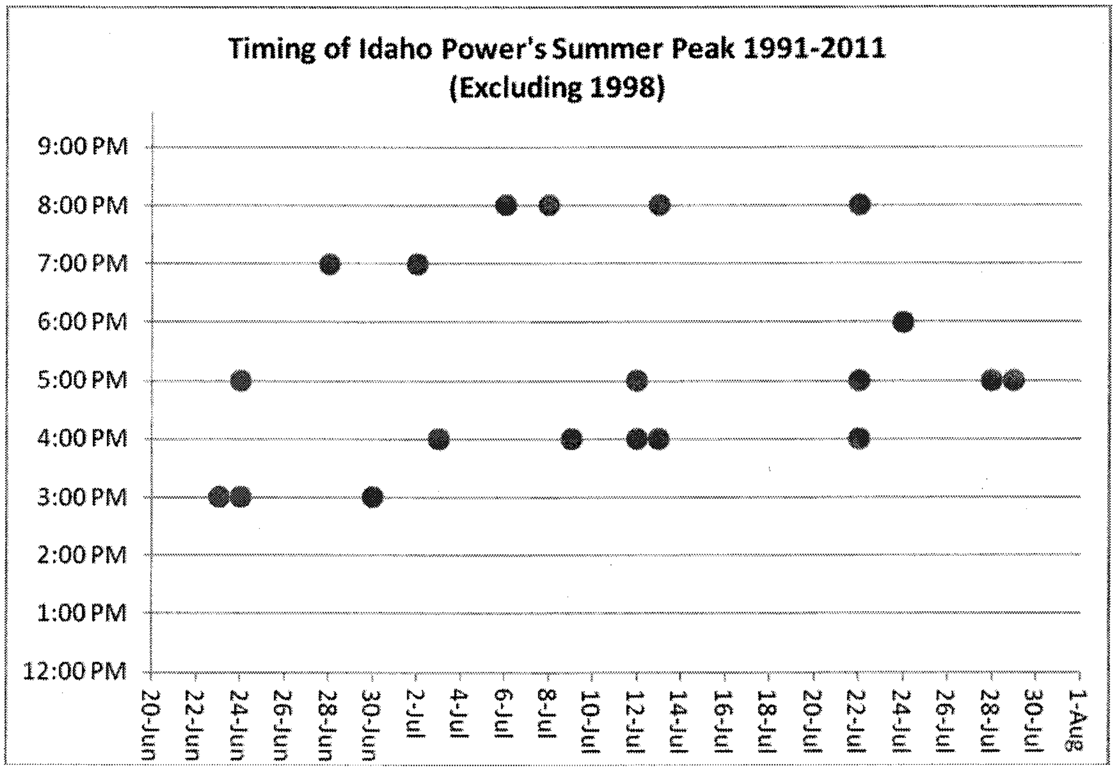
    b. For each year, identify the capacity factor that is exceeded 90% of the time.

Year 1			Year 2	
July 1 - 5 p.m.	83.4%		July 2 - 6 p.m.	83.1%
July 2 - 4 p.m.	76.4%		July 2 - 3 p.m.	82.8%
July 1 - 3 p.m.	75.6%		July 1 - 7 p.m.	82.3%
July 2 - 3 p.m.	75.5%		July 2 - 4 p.m.	82.3%
July 1 - 4 p.m.	74.5%		July 2 - 5 p.m.	82.1%
July 1 - 7 p.m.	74.1%		July 1 - 6 p.m.	81.5%
July 2 - 7 p.m.	74.0%		July 3 - 3 p.m.	76.9%
July 3 - 3 p.m.	74.0%		July 1 - 4 p.m.	76.5%
July 1 - 6 p.m.	73.1%		July 1 - 5 p.m.	76.5%
July 2 - 5 p.m.	72.9%		July 1 - 3 p.m.	74.1%
July 2 - 6 p.m.	71.1%		July 2 - 7 p.m.	71.3%

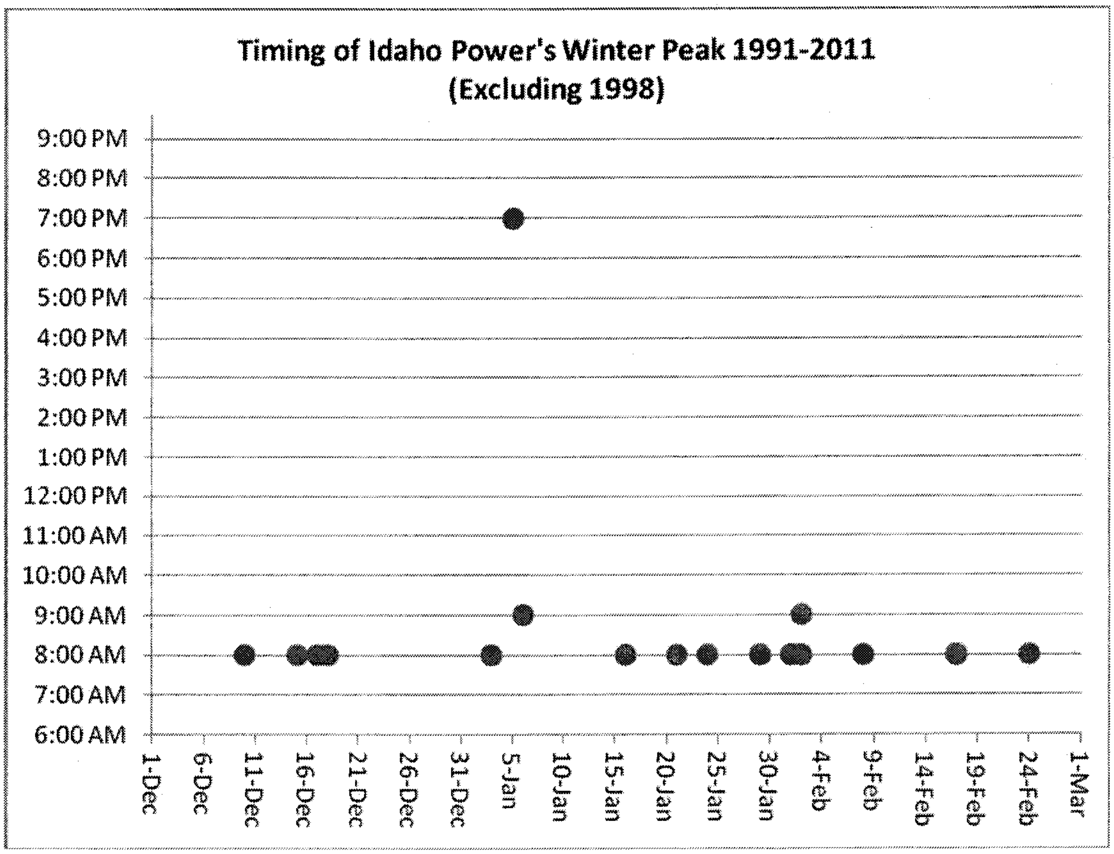
    c. Average the 90th percentile capacity factor across the two years.

90th percentile peak capacity factor = (72.9+74.1)/2 = 73.5%

Attachment 2: Timing of Idaho Power's Summer Peak



Attachment 3: Timing of Idaho Power's Winter Peak



Attachment No. 3
Case No. GNR-E-11-03
Staff Comments
3/25/13

Attachment 4: Planning assumptions of Northwest Power and Conservation Council's Sixth Power Plan

Northwest Power and Conservation Council
Sixth Power Plan
Appendix I

Resource Type	Equivalent Forced Outage Rate	Equivalent Annual Availability
Landfill Gas to Energy	8.0%	88%
Animal Manure Energy Recovery	8.0%	88%
Waste Water Treatment Energy Recovery	4.7%	93%
Woody Residue Power Plants	7.0%	86%
Geothermal	6.4%	90%
Average	6.8%	89%

Equivalent Forced Outage Rate (EFOR) is the hours of unit failure (unplanned outage hours and equivalent unplanned derated hours) given as a percentage of the total hours of the availability of that unit (unplanned outage, unplanned derated, and service hours).

Equivalent annual availability represents the amount of time that a plant is able to produce electricity in a year, divided by the amount of the time in the year. Occasions where only partial capacity is available are deducted.

Rates based on Staff's proposed capacity factors

AVISTA
AVOIDED COST RATES FOR NON-SEASONAL HYDRO PROJECTS
March 25, 2013
$/MWh
New Contract

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2012	2013	2014	2015	2016	2017	CONTRACT YEAR	NON-LEVELIZED RATES
1	30.53	30.35	30.25	33.34	34.38	35.49	2012	30.53
2	30.45	30.30	31.73	33.84	34.91	36.12	2013	30.35
3	30.39	31.24	32.54	34.34	35.49	36.84	2014	30.25
4	31.04	31.93	33.19	34.89	36.15	43.60	2015	33.34
5	31.60	32.53	33.80	35.49	41.44	48.26	2016	34.38
6	32.12	33.10	34.43	39.80	45.45	51.90	2017	35.49
7	32.64	33.70	38.08	43.26	48.74	54.83	2018	36.81
8	33.18	36.81	41.13	46.22	51.49	57.24	2019	38.48
9	35.87	39.51	43.81	48.75	53.79	59.25	2020	67.52
10	38.24	41.92	46.15	50.91	55.75	61.02	2021	71.24
11	40.41	44.05	48.17	52.78	57.49	62.66	2022	75.33
12	42.35	45.93	49.95	54.45	59.11	64.16	2023	78.56
13	44.08	47.59	51.55	56.01	60.58	65.51	2024	80.88
14	45.62	49.10	53.04	57.44	61.92	66.78	2025	82.93
15	47.04	50.52	54.41	58.74	63.17	67.98	2026	85.62
16	48.36	51.82	55.67	59.96	64.35	69.11	2027	89.17
17	49.59	53.02	56.85	61.11	65.47	70.18	2028	91.95
18	50.72	54.14	57.96	62.19	66.53	71.24	2029	94.38
19	51.79	55.20	59.01	63.22	67.57	72.29	2030	97.45
20	52.79	56.21	60.00	64.22	68.59	73.27	2031	100.68
							2032	103.98
							2033	107.23
							2034	112.11
							2035	117.22
							2036	119.85
							2037	124.06

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

Rates based on Staff's proposed capacity factors

AVISTA
AVOIDED COST RATES FOR SEASONAL HYDRO PROJECTS
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$/MWh
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Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2012	2013	2014	2015	2016	2017	CONTRACT YEAR	NON-LEVELIZED RATES
1	30.53	30.35	30.25	33.34	34.38	35.49	2012	30.53
2	30.45	30.30	31.73	33.84	34.91	36.12	2013	30.35
3	30.39	31.24	32.54	34.34	35.49	36.84	2014	30.25
4	31.04	31.93	33.19	34.89	36.15	48.79	2015	33.34
5	31.60	32.53	33.80	35.49	45.42	56.61	2016	34.38
6	32.12	33.10	34.43	42.97	52.11	62.39	2017	35.49
7	32.64	33.70	40.68	48.72	57.34	66.89	2018	36.81
8	33.18	38.99	45.70	53.41	61.57	70.48	2019	38.48
9	37.71	43.38	49.92	57.31	65.03	73.44	2020	91.11
10	41.58	47.17	53.50	60.58	67.94	75.99	2021	95.18
11	44.96	50.43	56.56	63.36	70.48	78.28	2022	99.61
12	47.93	53.26	59.20	65.81	72.76	80.33	2023	103.20
13	50.53	55.73	61.54	68.03	74.81	82.17	2024	105.88
14	52.82	57.94	63.67	70.03	76.65	83.86	2025	108.29
15	54.89	59.96	65.60	71.84	78.35	85.43	2026	111.35
16	56.79	61.80	67.35	73.50	79.92	86.89	2027	115.28
17	58.53	63.48	68.97	75.05	81.39	88.27	2028	118.44
18	60.12	65.03	70.47	76.49	82.77	89.60	2029	121.26
19	61.59	66.47	71.88	77.84	84.10	90.90	2030	124.73
20	62.96	67.82	73.19	79.14	85.38	92.11	2031	128.35
							2032	132.06
							2033	135.72
							2034	141.02
							2035	146.55
							2036	149.61
							2037	154.26

Note: Staff proposes that seasonal hydro projects be defined as those hydro projects that, over the last ten years, generated at least 90 percent of its average annual generation during the months of April through October.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

Rates based on Staff's proposed capacity factors

AVISTA
AVOIDED COST RATES FOR OTHER PROJECTS
March 25, 2013
$/MWh
New Contract

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2012	2013	2014	2015	2016	2017	CONTRACT YEAR	NON-LEVELIZED RATES
1	30.53	30.35	30.25	33.34	34.38	35.49	2012	30.53
2	30.45	30.30	31.73	33.84	34.91	36.12	2013	30.35
3	30.39	31.24	32.54	34.34	35.49	36.84	2014	30.25
4	31.04	31.93	33.19	34.89	36.15	42.24	2015	33.34
5	31.60	32.53	33.80	35.49	40.40	46.07	2016	34.38
6	32.12	33.10	34.43	38.97	43.70	49.15	2017	35.49
7	32.64	33.70	37.40	41.84	46.49	51.68	2018	36.81
8	33.18	36.24	39.94	44.34	48.85	53.77	2019	38.48
9	35.38	38.49	42.21	46.51	50.85	55.54	2020	61.36
10	37.37	40.54	44.22	48.38	52.56	57.11	2021	64.99
11	39.22	42.39	45.98	50.01	54.09	58.58	2022	68.98
12	40.90	44.02	47.53	51.49	55.54	59.93	2023	72.12
13	42.40	45.47	48.94	52.87	56.86	61.16	2024	74.35
14	43.74	46.79	50.26	54.15	58.07	62.32	2025	76.30
15	44.98	48.05	51.49	55.32	59.21	63.41	2026	78.89
16	46.16	49.21	52.62	56.42	60.29	64.46	2027	82.34
17	47.25	50.29	53.68	57.46	61.31	65.46	2028	85.02
18	48.27	51.30	54.69	58.46	62.28	66.45	2029	87.35
19	49.23	52.26	55.64	59.40	63.25	67.43	2030	90.32
20	50.14	53.17	56.55	60.32	64.20	68.34	2031	93.45
							2032	96.65
							2033	99.78
							2034	104.56
							2035	109.55
							2036	112.07
							2037	116.17

Note: "Other projects" refers to projects other than wind, solar, hydro, and canal drop hydro projects. These "Other projects" may include (but are not limited to): cogeneration, biomass, biogas, landfill gas, or geothermal projects.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

Rates based on Staff's proposed capacity factors

IDAHO POWER COMPANY
AVOIDED COST RATES FOR NON-SEASONAL HYDRO PROJECTS
March 25, 2013
$/MWh
New Contract

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2012	2013	2014	2015	2016	2017		
1	30.53	30.35	34.03	59.05	60.46	61.94	2012	30.53
2	30.44	32.12	46.05	59.72	61.17	62.76	2013	30.35
3	31.55	40.40	50.48	60.41	61.93	63.67	2014	34.03
4	37.63	44.84	53.02	61.13	62.77	64.44	2015	59.05
5	41.51	47.75	54.82	61.91	63.52	65.54	2016	60.46
6	44.28	49.90	56.30	62.62	64.51	66.81	2017	61.94
7	46.44	51.67	57.51	63.54	65.68	68.08	2018	63.65
8	48.24	53.11	58.76	64.60	66.84	69.24	2019	65.72
9	49.75	54.52	60.05	65.68	67.93	70.30	2020	67.16
10	51.19	55.92	61.29	66.70	68.93	71.32	2021	70.87
11	52.61	57.25	62.43	67.64	69.90	72.36	2022	74.95
12	53.94	58.46	63.48	68.56	70.88	73.35	2023	78.18
13	55.16	59.57	64.48	69.48	71.83	74.30	2024	80.49
14	56.28	60.61	65.47	70.38	72.73	75.23	2025	82.53
15	57.33	61.63	66.41	71.24	73.62	76.14	2026	85.22
16	58.35	62.60	67.31	72.08	74.48	77.03	2027	88.76
17	59.32	63.52	68.18	72.90	75.33	77.90	2028	91.53
18	60.22	64.40	69.02	73.70	76.15	78.78	2029	93.96
19	61.10	65.25	69.83	74.49	76.99	79.68	2030	97.03
20	61.93	66.07	70.63	75.28	77.85	80.53	2031	100.25
							2032	103.55
							2033	106.79
							2034	111.67
							2035	116.77
							2036	119.39
							2037	123.60

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

Rates based on Staff's proposed capacity factors

IDAHO POWER COMPANY
AVOIDED COST RATES FOR SEASONAL HYDRO PROJECTS
March 25, 2013
$/MWh
New Contract

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2012	2013	2014	2015	2016	2017		
1	30.53	30.35	36.16	80.70	82.42	84.23	2012	30.53
2	30.44	33.14	57.55	81.53	83.29	85.21	2013	30.35
3	32.20	47.77	65.20	82.36	84.21	86.27	2014	36.16
4	42.94	55.44	69.41	83.22	85.19	87.19	2015	80.70
5	49.64	60.33	72.28	84.15	86.08	88.43	2016	82.42
6	54.34	63.85	74.50	85.00	87.22	89.85	2017	84.23
7	57.90	66.61	76.28	86.06	88.53	91.26	2018	86.26
8	60.77	68.84	77.98	87.26	89.83	92.56	2019	88.66
9	63.13	70.88	79.64	88.47	91.05	93.75	2020	90.43
10	65.27	72.80	81.20	89.61	92.18	94.91	2021	94.49
11	67.27	74.56	82.63	90.68	93.28	96.08	2022	98.91
12	69.11	76.16	83.93	91.72	94.39	97.20	2023	102.49
13	70.77	77.60	85.16	92.77	95.46	98.27	2024	105.16
14	72.27	78.95	86.35	93.78	96.48	99.32	2025	107.56
15	73.66	80.24	87.49	94.75	97.47	100.34	2026	110.62
16	74.99	81.46	88.56	95.70	98.45	101.35	2027	114.53
17	76.23	82.59	89.60	96.63	99.41	102.33	2028	117.68
18	77.39	83.68	90.59	97.54	100.34	103.32	2029	120.49
19	78.50	84.72	91.55	98.42	101.28	104.32	2030	123.95
20	79.55	85.72	92.48	99.32	102.24	105.28	2031	127.56
							2032	131.26
							2033	134.91
							2034	140.20
							2035	145.71
							2036	148.76
							2037	153.40

Note: Staff proposes that seasonal hydro projects be defined as those hydro projects that, over the last ten years, generated at least 90 percent of its average annual generation during the months of April through October.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

Rates based on Staff's proposed capacity factors

IDAHO POWER COMPANY
AVOIDED COST RATES FOR OTHER PROJECTS
March 25, 2013
$/MWh
New Contract

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2012	2013	2014	2015	2016	2017	CONTRACT YEAR	NON-LEVELIZED RATES
1	30.53	30.35	32.38	53.39	54.72	56.12	2012	30.53
2	30.44	31.33	42.47	54.03	55.39	56.90	2013	30.35
3	31.04	38.11	46.23	54.67	56.11	57.77	2014	32.38
4	35.99	41.78	48.42	55.35	56.91	58.50	2015	53.39
5	39.17	44.22	50.00	56.09	57.62	59.55	2016	54.72
6	41.47	46.05	51.32	56.77	58.58	60.79	2017	56.12
7	43.28	47.58	52.41	57.65	59.70	62.02	2018	57.74
8	44.82	48.84	53.56	58.68	60.84	63.14	2019	59.72
9	46.11	50.10	54.76	59.73	61.89	64.16	2020	61.07
10	47.38	51.37	55.93	60.71	62.85	65.15	2021	64.70
11	48.65	52.59	57.01	61.62	63.79	66.15	2022	68.68
12	49.86	53.71	58.00	62.50	64.74	67.12	2023	71.82
13	50.97	54.73	58.94	63.40	65.66	68.04	2024	74.05
14	51.99	55.70	59.88	64.27	66.53	68.93	2025	75.99
15	52.95	56.66	60.78	65.09	67.38	69.81	2026	78.58
16	53.90	57.57	61.64	65.90	68.22	70.67	2027	82.03
17	54.80	58.43	62.46	66.69	69.03	71.51	2028	84.70
18	55.64	59.26	63.27	67.47	69.83	72.37	2029	87.02
19	56.46	60.06	64.05	68.23	70.65	73.24	2030	89.99
20	57.24	60.83	64.81	69.00	71.47	74.06	2031	93.11
							2032	96.31
							2033	99.44
							2034	104.21
							2035	109.20
							2036	111.71
							2037	115.81

Note: "Other projects" refers to projects other than wind, solar, hydro, and canal drop hydro projects. These "Other projects" may include (but are not limited to): cogeneration, biomass, biogas, landfill gas, or geothermal projects.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

Rates based on Staff's proposed capacity factors

PACIFICORP
AVOIDED COST RATES FOR NON-SEASONAL HYDRO PROJECTS
March 25, 2013
$/MWh
New Contract

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2012	2013	2014	2015	2016	2017		
1	30.53	30.35	55.03	58.49	59.89	61.37	2012	30.53
2	30.44	42.22	56.70	59.16	60.60	62.19	2013	30.35
3	38.02	47.23	57.68	59.84	61.36	63.09	2014	55.03
4	42.56	50.04	58.50	60.56	62.20	63.86	2015	58.49
5	45.52	51.97	59.28	61.34	62.94	64.95	2016	59.89
6	47.68	53.49	60.08	62.05	63.94	66.23	2017	61.37
7	49.41	54.79	60.80	62.97	65.11	67.50	2018	63.07
8	50.89	55.90	61.69	64.04	66.28	68.67	2019	65.13
9	52.14	57.05	62.71	65.12	67.37	69.73	2020	66.56
10	53.39	58.25	63.73	66.14	68.37	70.75	2021	70.26
11	54.65	59.41	64.70	67.09	69.34	71.80	2022	74.33
12	55.86	60.49	65.61	68.01	70.33	72.80	2023	77.56
13	56.98	61.48	66.49	68.95	71.29	73.76	2024	79.86
14	58.01	62.44	67.39	69.85	72.20	74.69	2025	81.89
15	58.99	63.38	68.25	70.72	73.09	75.61	2026	84.57
16	59.95	64.29	69.08	71.56	73.96	76.51	2027	88.10
17	60.87	65.15	69.89	72.40	74.82	77.38	2028	90.87
18	61.74	65.99	70.68	73.21	75.66	78.28	2029	93.28
19	62.57	66.80	71.46	74.00	76.51	79.19	2030	96.34
20	63.38	67.59	72.22	74.81	77.38	80.06	2031	99.55
							2032	102.84
							2033	106.07
							2034	110.94
							2035	116.03
							2036	118.64
							2037	122.84

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

Rates based on Staff's proposed capacity factors

PACIFICORP
AVOIDED COST RATES FOR SEASONAL HYDRO PROJECTS
March 25, 2013
$/MWh
New Contract

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2012	2013	2014	2015	2016	2017		
1	30.53	30.35	75.91	79.67	81.38	83.18	2012	30.53
2	30.44	52.26	77.72	80.49	82.24	84.15	2013	30.35
3	44.45	60.70	78.85	81.32	83.15	85.20	2014	75.91
4	52.27	65.29	79.81	82.18	84.14	86.12	2015	79.67
5	57.24	68.34	80.73	83.10	85.02	87.36	2016	81.38
6	60.77	70.64	81.66	83.95	86.16	88.78	2017	83.18
7	63.51	72.54	82.52	85.01	87.46	90.19	2018	85.19
8	65.78	74.12	83.54	86.21	88.77	91.49	2019	87.58
9	67.66	75.66	84.68	87.42	89.99	92.68	2020	89.33
10	69.44	77.19	85.83	88.57	91.12	93.84	2021	93.37
11	71.14	78.64	86.93	89.64	92.22	95.01	2022	97.78
12	72.74	79.98	87.95	90.68	93.34	96.14	2023	101.34
13	74.19	81.21	88.95	91.74	94.41	97.22	2024	104.00
14	75.53	82.38	89.96	92.76	95.44	98.27	2025	106.38
15	76.78	83.52	90.94	93.74	96.44	99.30	2026	109.42
16	77.98	84.61	91.87	94.69	97.43	100.32	2027	113.32
17	79.12	85.64	92.79	95.63	98.40	101.30	2028	116.45
18	80.20	86.63	93.68	96.55	99.34	102.31	2029	119.24
19	81.22	87.59	94.56	97.44	100.29	103.32	2030	122.68
20	82.21	88.51	95.42	98.35	101.26	104.29	2031	126.28
							2032	129.96
							2033	133.59
							2034	138.86
							2035	144.36
							2036	147.39
							2037	152.01

Note: Staff proposes that seasonal hydro projects be defined as those hydro projects that, over the last ten years, generated at least 90 percent of its average annual generation during the months of April through October.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

Rates based on Staff's proposed capacity factors

PACIFICORP
AVOIDED COST RATES FOR OTHER PROJECTS
March 25, 2013
$/MWh
New Contract

Eligibility for these rates is limited to wind and solar projects 100 kW or smaller, and to non-wind and non-solar projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2012	2013	2014	2015	2016	2017		
1	30.53	30.35	49.58	52.95	54.27	55.67	2012	30.53
2	30.44	39.60	51.20	53.59	54.95	56.45	2013	30.35
3	36.34	43.71	52.15	54.23	55.67	57.32	2014	49.58
4	40.03	46.06	52.93	54.91	56.47	58.05	2015	52.95
5	42.46	47.70	53.67	55.65	57.17	59.10	2016	54.27
6	44.26	49.00	54.43	56.33	58.13	60.34	2017	55.67
7	45.72	50.15	55.13	57.21	59.26	61.57	2018	57.29
8	46.99	51.14	55.98	58.25	60.40	62.70	2019	59.26
9	48.08	52.19	56.96	59.30	61.45	63.73	2020	60.60
10	49.20	53.29	57.96	60.28	62.42	64.72	2021	64.22
11	50.34	54.38	58.89	61.20	63.36	65.73	2022	68.20
12	51.45	55.39	59.77	62.09	64.32	66.70	2023	71.34
13	52.48	56.33	60.62	62.99	65.25	67.62	2024	73.55
14	53.43	57.23	61.49	63.87	66.12	68.53	2025	75.49
15	54.34	58.12	62.32	64.70	66.99	69.41	2026	78.07
16	55.24	58.98	63.12	65.52	67.83	70.28	2027	81.51
17	56.10	59.80	63.90	66.32	68.66	71.13	2028	84.18
18	56.91	60.59	64.67	67.11	69.47	72.00	2029	86.50
19	57.70	61.37	65.42	67.88	70.29	72.89	2030	89.46
20	58.46	62.12	66.15	68.66	71.13	73.72	2031	92.57
							2032	95.76
							2033	98.88
							2034	103.64
							2035	108.62
							2036	111.13
							2037	115.22

Note: "Other projects" refers to projects other than wind, solar, hydro, and canal drop hydro projects. These "Other projects" may include (but are not limited to): cogeneration, biomass, biogas, landfill gas, or geothermal projects.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2012 released June 25, 2012. See "Annual Energy Outlook 2012, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS **25TH** DAY OF MARCH 2013, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. GNR-E-11-03, BY E-MAILING A COPY THEREOF TO THE FOLLOWING:

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