e-FILING REPORT COVER SHEET

REPORT NAME: Time Differentiated Cost of Service Data Report

COMPANY NAME: Idaho Power Company

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☐ No ☒ Yes

If yes, please submit only the cover letter electronically. Submit confidential information as directed OAR 860-001-0070 or the terms of an applicable protective order.

If known, please select designation: ☒ RE (Electric) ☐ RG (Gas) ☐ RW (Water)

☐ RO (Other)

Report is required by: ☐ OAR

☐ Statute

☒ Order No. 12-159

☐ Other

Is this report associated with a specific docket/case? ☐ No ☒ Yes

If Yes, enter docket number: UM 1415

Key words:

If known, please select the PUC Section to which the report should be directed:

☐ Corporate Analysis and Water Regulation

☐ Economic and Policy Analysis

☐ Electric and Natural Gas Revenue Requirements

☐ Electric Rates and Planning

☐ Natural Gas Rates and Planning

☐ Utility Safety, Reliability & Security

☐ Administrative Hearings Division

☐ Consumer Services Section

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- **Annual Fee Statement form and payment remittance or**
- **OUS or RSPF Surcharge form or surcharge remittance or**
- **Any other Telecommunications Reporting or**
- **Any daily safety or safety incident reports or**
- **Accident reports required by ORS 654.715.**

IDAHO POWER
An IDACORP Company

Matt Larkin
Regulatory Analyst

August 8, 2012

Attention: Filing Center
Public Utility Commission of Oregon
550 Capitol Street NE, Suite 215
P. O. Box 2148
Salem, OR 97308-2148

RE: Compliance Filing in Docket UM 1415
Time Differentiated Cost of Service Data Report

Dear Sir or Madam:

On May 8, 2012, the Public Utility Commission of Oregon ("Commission") issued Order No. 12-159 in Docket UM 1415 requiring utilities to provide data regarding the cost of providing electric service at different times throughout the year. The initial deadline set by the Commission was within sixty days of the order date, or July 9, 2012. On July 3, 2012, Idaho Power Company requested a one-month extension of this deadline to August 8, 2012, which was granted in Order No. 12-282 issued on July 6, 2012. Pursuant to the requirements of Order No. 12-159 and modified by Order No. 12-282, enclosed please find a copy of Idaho Power Company's Time Differentiated Cost of Service Data Report.

If you have any questions regarding this report, please direct them to me at (208) 388-2461, or Scott Wright at (208) 388-5493.

Very truly yours,

Matt Larkin

ML/kkt
Enclosures
cc/enc: Greg Said
Tim Tatum
Lisa Nordstrom
Lisa Rackner
RA Files
Legal Files

P.O. Box 70 (83707)
1221 W. Idaho St.
Boise, ID 83702

Idaho Power Company
Compliance with Order No. 12-159
Time Differentiated Cost of Service Data

I. Background

On May 8, 2012, the Public Utility Commission of Oregon ("Commission") issued Order No. 12-159 in Docket UM 1415 regarding cost methods for use in developing electric rate spreads. In ordering paragraph 2 of Order No. 12-159, utilities were directed to provide the Commission with detailed cost information associated with providing electrical service at different times within the year.

The initial deadline for providing the information set by Order No. 12-159 was within 60 days of the order issue date, or July 9, 2012. However, due to the high level of granularity requested by the Commission, Idaho Power Company ("Idaho Power" or "Company") determined that it would not be able to gather the requested data by the July 9 deadline, and contacted Commission Staff ("Staff") to discuss an extension. On July 3, 2012, the Company filed, with support from Staff, a request for extension of the submission deadline to August 8, 2012. On July 6, 2012, the Commission issued an order approving the Company's request. The following report contains the Company's complete cost data analysis in compliance with Directive 1 of Order No. 12-159.

II. Study Overview

Directive 1, listed on page 7 of Order No. 12-159, reads as follows:

> Within 60 days of entry of this order, we direct the electric utilities to provide the Commission with detailed information on the cost of serving Oregon customers during different time periods within the year. This cost data should be sufficiently granular to appropriately construct the specifics of both price and duration of on-peak, shoulder, and off-peak rates. The utilities are directed to develop best estimates of meaningful hourly marginal cost values, given their individual load and dispatch-cost structures, and provide this data as well.

The following report has been prepared in accordance with this directive. The cost of service information presented in this report is segmented into two sections: (1) time differentiated variable costs of service presented on an embedded cost basis and on a marginal cost basis and (2) seasonally differentiated embedded fixed costs of service. For the purpose of this report, the Company has defined variable costs of service to be only net power supply expenses, which consist of fuel and purchased power net of surplus sales.

III. <u>Variable Cost of Service</u>

The Company utilized the AURORAxmp ("AURORA") modeling software to estimate hourly net power supply expenses on both an embedded cost basis and a marginal cost basis. To calculate the embedded variable cost of energy, the Company used modeling assumptions approved in its most recent Annual Power Cost Update filing, Docket UE 242, reflecting an April 2012 through March 2013 forecast test year. The median water condition was selected from a range of hydro conditions spanning from 1928 to 2010 as the hydro condition utilized in the hourly cost modeling of both the embedded and marginal cost outputs. Expenses and generation associated with Public Utility Regulatory Policies Act of 1978 ("PURPA") projects were not included in the hourly per unit cost output because the costs associated with these resources do not vary by hour. Because variations in PURPA generation are modeled in AURORA on a monthly basis, the inclusion of PURPA-associated expenses in the hourly output data would add a constant cost across all hours within each month, thus muting hourly expense variations calculated by the AURORA model.

To calculate the Company's marginal cost of energy, four additional years were modeled in the AURORA software to estimate the variable energy cost of serving the Company's forecasted load for the April 2013 through March 2017 time period. These four years, in addition to the March 2012 through April 2013 forecast test year, served as the base case reflecting the Company's expected variable energy costs from April 2012 through March 2017. To estimate hourly marginal net power supply expenses, the Company reran all five years in the forecast period with the addition of 50 megawatts ("MW") of load across all hours. The marginal cost of energy for each year is the difference between the base year cost and the "base year plus 50 MW" cost divided by the difference between the base year energy and the "base year plus 50 MW" energy. The five years were then averaged to calculate the Company's average hourly marginal cost of energy.

Please note that the data calculated in this model and presented in the following pages was compiled for the specific purpose of providing the Commission with an indication of the varying costs of providing electric service at different time periods throughout the year. This does not reflect a comprehensive cost of service analysis and should therefore be used for informational purposes only.

A. Embedded Study Results

Figures 1 through 4 reflect the embedded variable cost of energy at different times of the year, i.e., the variable energy cost of serving the Company's expected load during the April 2012 through March 2013 forecast test year. All values reflect net power supply expenses in dollars per megawatt-hour ("MWh").

Figure 1: Annual Embedded Cost in Terms of Average Monthly Cost

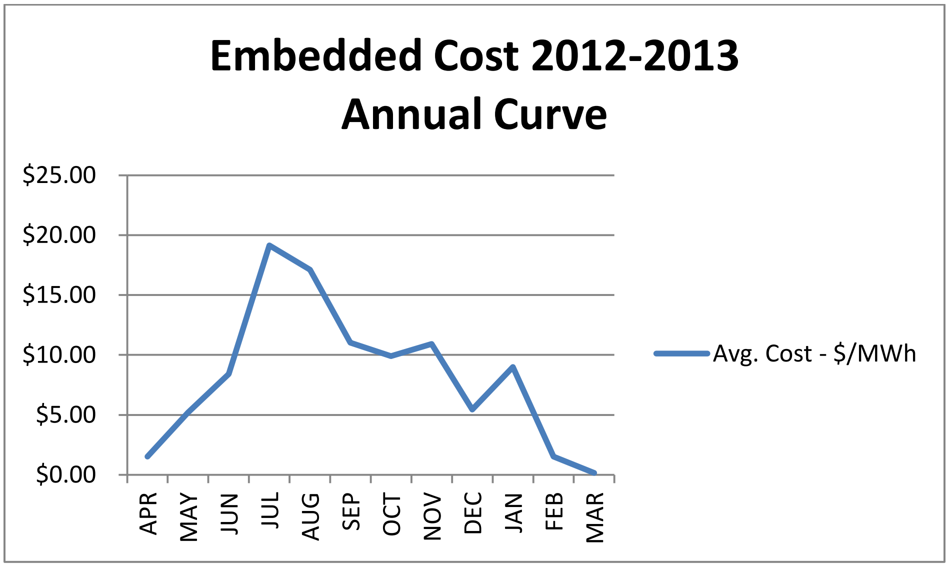


Figure 2: Weekly Embedded Cost in Terms of Average Daily Cost, Separated by Season

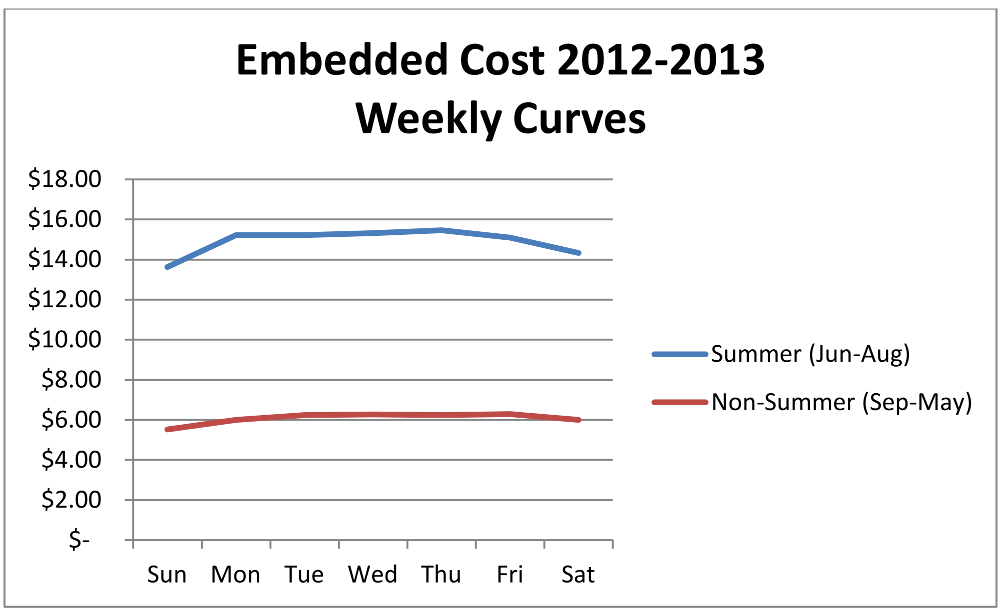


Figure 3a: Summer Time-of-Day Embedded Cost in Terms of Average Cost per Month[1]

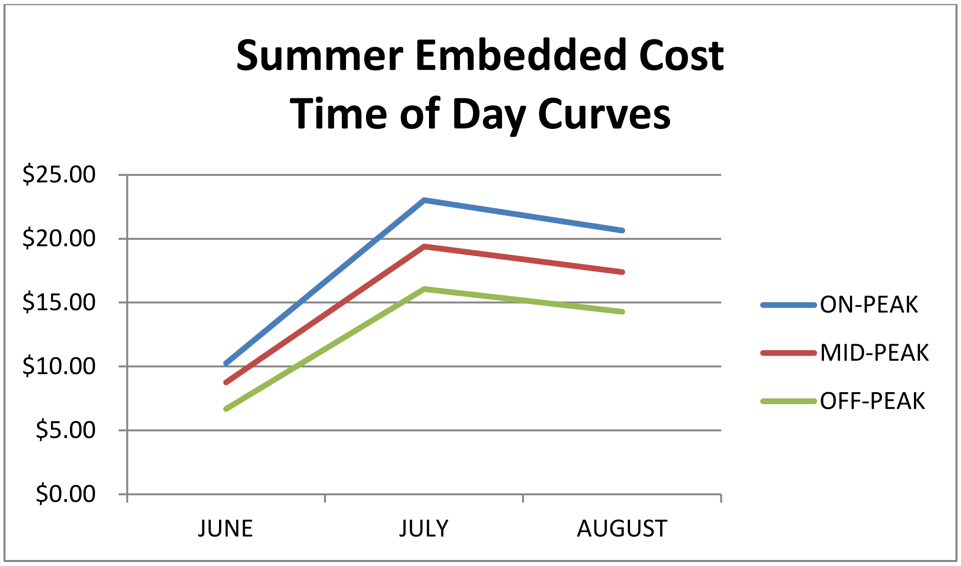
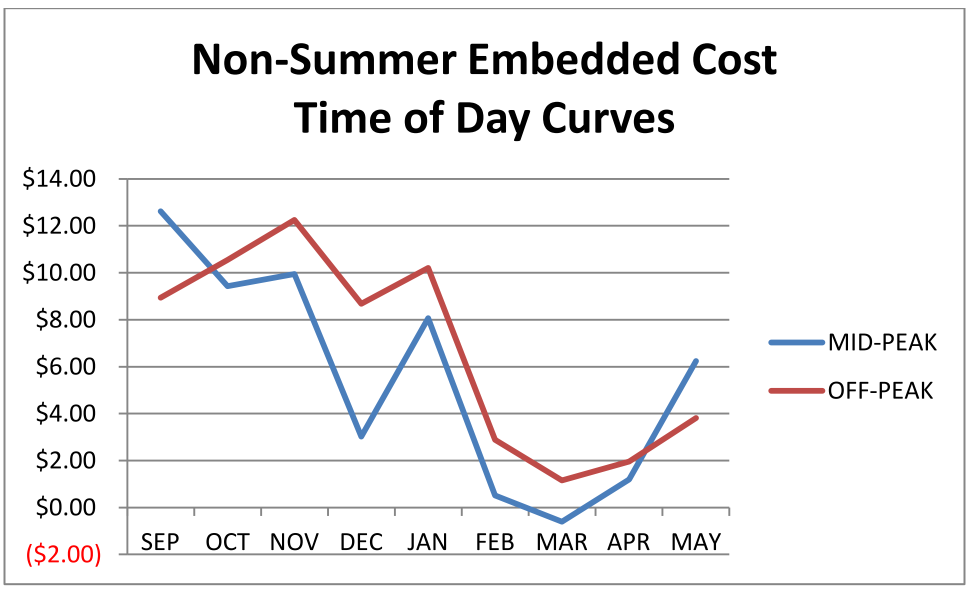


Figure 3b: Non-Summer Time-of-Day Embedded Cost in Terms of Average Cost per Month



[1] Time periods are defined in the Company's Tariff Schedules 9 and 19 as follows:

Summer On-Peak	1 p.m. to 9 p.m. Monday through Friday, except holidays
Summer Mid-Peak	7 a.m. to 1 p.m. and 9 p.m. to 11 p.m. Monday through Friday, except holidays, and 7 a.m. to 11 p.m. Saturday and Sunday, except holidays
Summer Off-Peak	11 p.m. to 7 a.m. Monday through Sunday and all hours on holidays
Non-Summer Mid-Peak	7 a.m. to 11 p.m. Monday through Saturday, except holidays
Non-Summer Off-Peak	11 p.m. to 7 a.m. Monday through Saturday and all hours on Sunday and holidays

Figure 4a: Weekday (Monday–Friday) Average Hourly Embedded Cost, Separated by Season

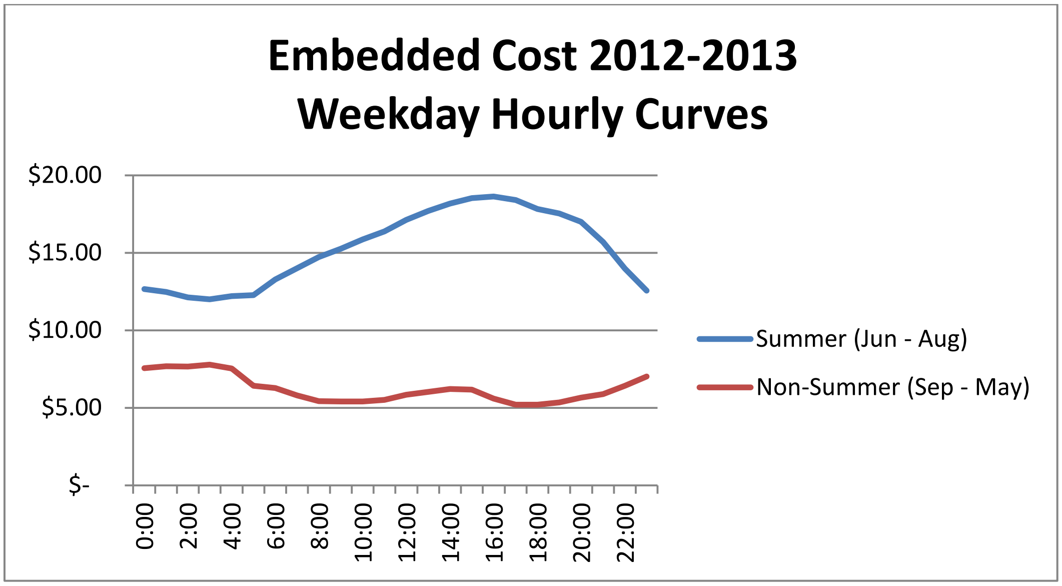
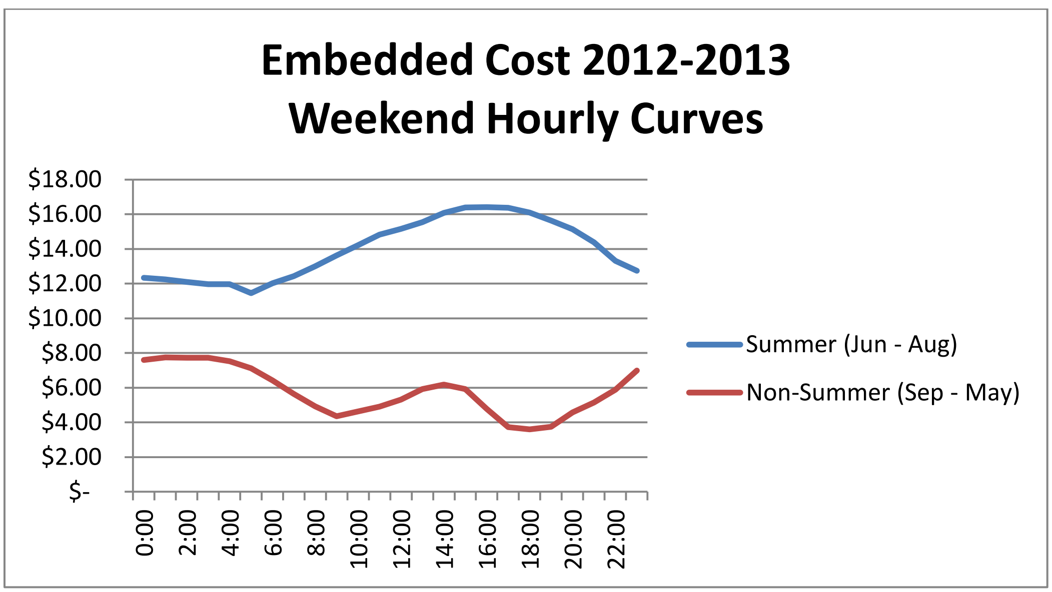


Figure 4b: Weekend (Saturday–Sunday) Average Hourly Embedded Cost, Separated by Season



Hourly embedded cost data supporting these figures is provided in the confidential workpaper file as Table 2. Because this information is confidential it will be provided under separate cover in accordance with Protective Order No. 09-147 issued in this docket.

PURPA Expenses: Because PURPA expenses were removed from the hourly data output, a forecast of monthly PURPA costs is provided in Table 1 to illustrate variations in these costs over the course of the year. This forecast is consistent with the monthly PURPA costs included in the Company's most recent net power supply expense forecast approved in Docket UE 242, reflecting the April 2012 through March 2013 test year.

Table 1: Monthly PURPA Expense Forecast

Monthly PURPA Expense April 2012 through March 2013 Exhibit 202, Docket UE 242	
April	$14,067,150
May	$17,028,048
June	$19,882,458
July	$20,357,076
August	$18,666,456
September	$16,849,047
October	$15,803,766
November	$15,673,114
December	$16,687,798
January	$12,616,167
February	$12,661,462
March	$11,733,653
Total	$192,026,192

B. Marginal Study Results

Figures 5 through 8 reflect the marginal cost of energy at different times of the year, i.e., the cost of serving an incremental 50 MW of load across all hours over the five-year forecast period as described above. All values reflect net power supply expenses in dollars per MWh.

Figure 5: Annual Marginal Cost in Terms of Average Cost per Month

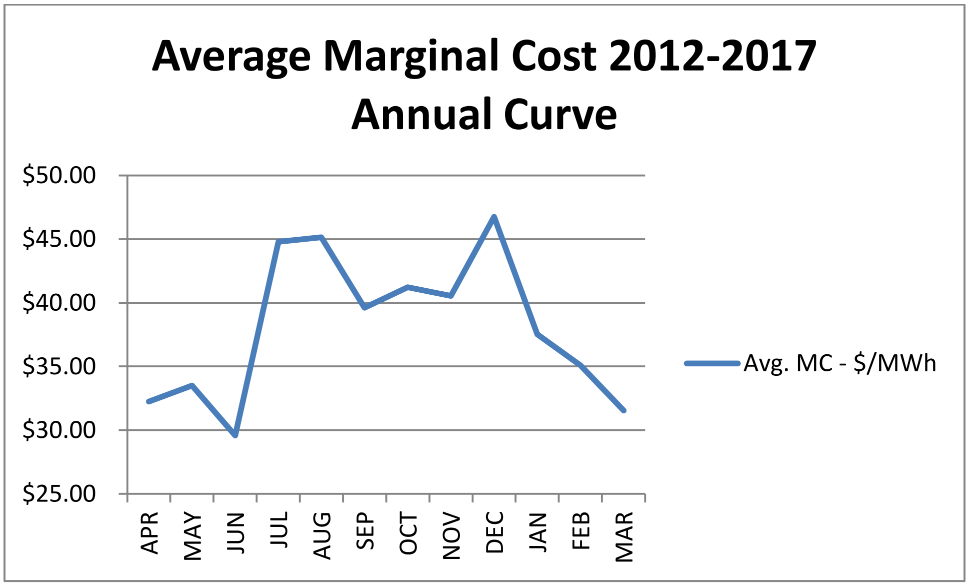


Figure 6: Weekly Marginal Cost in Terms of Average Daily Cost, Separated by Season

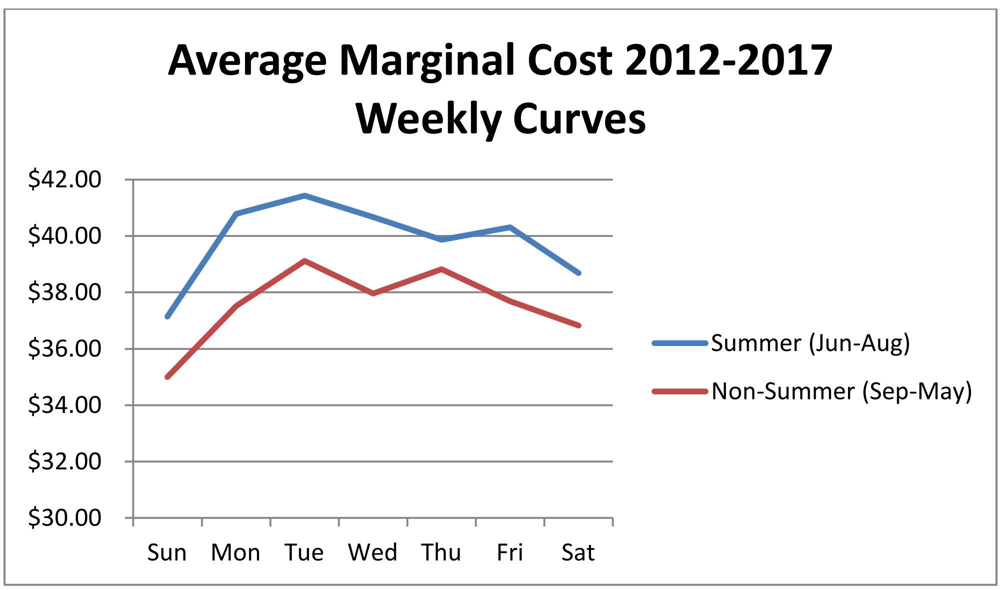


Figure 7a: Summer Time-of-Day Average Marginal Cost in Terms of Average Cost per Month

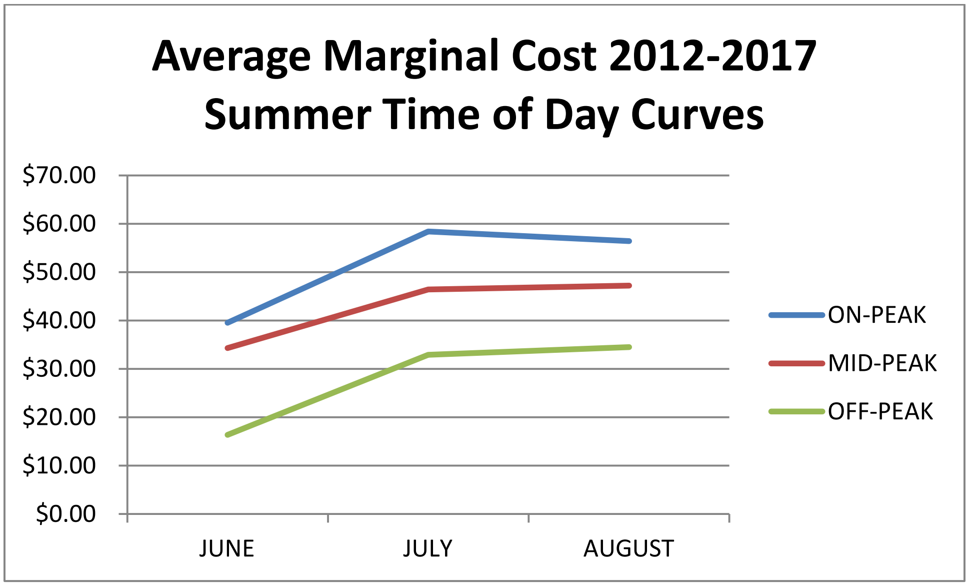


Figure 7b: Non-Summer Time-of-Day Average Marginal Cost in Terms of Average Cost per Month

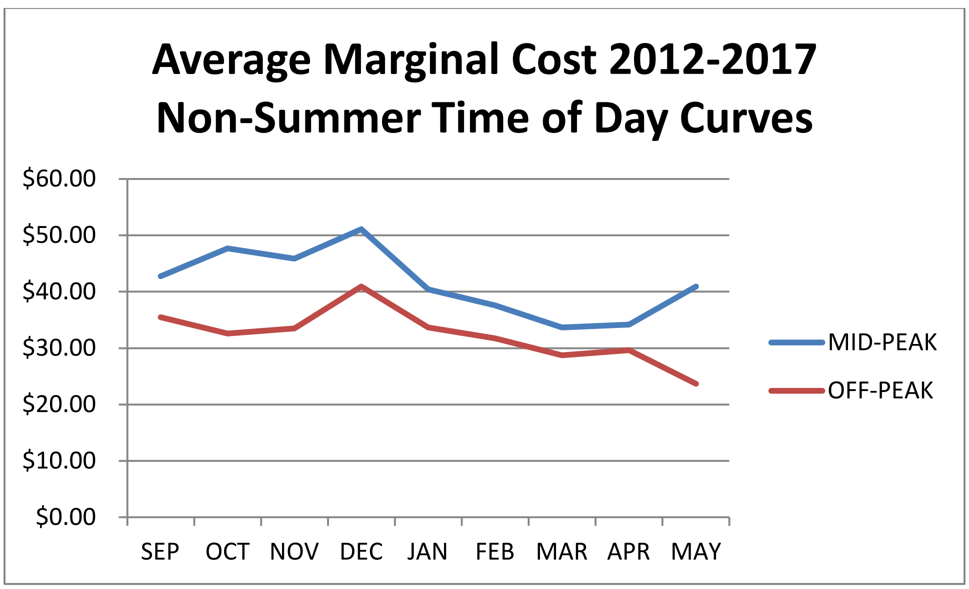


Figure 8a: Weekday (Monday–Friday) Average Hourly Marginal Cost, Separated by Season

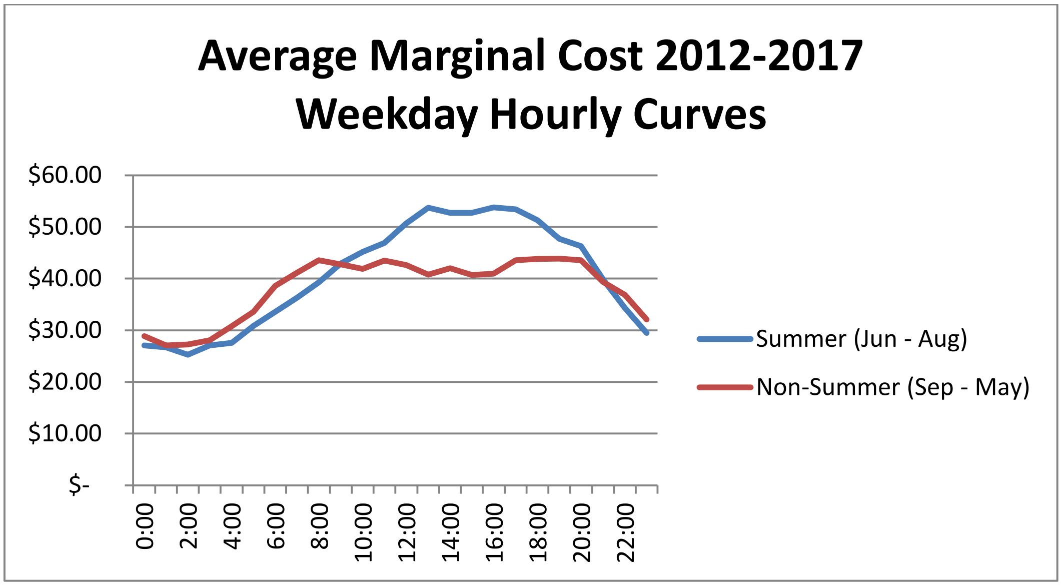
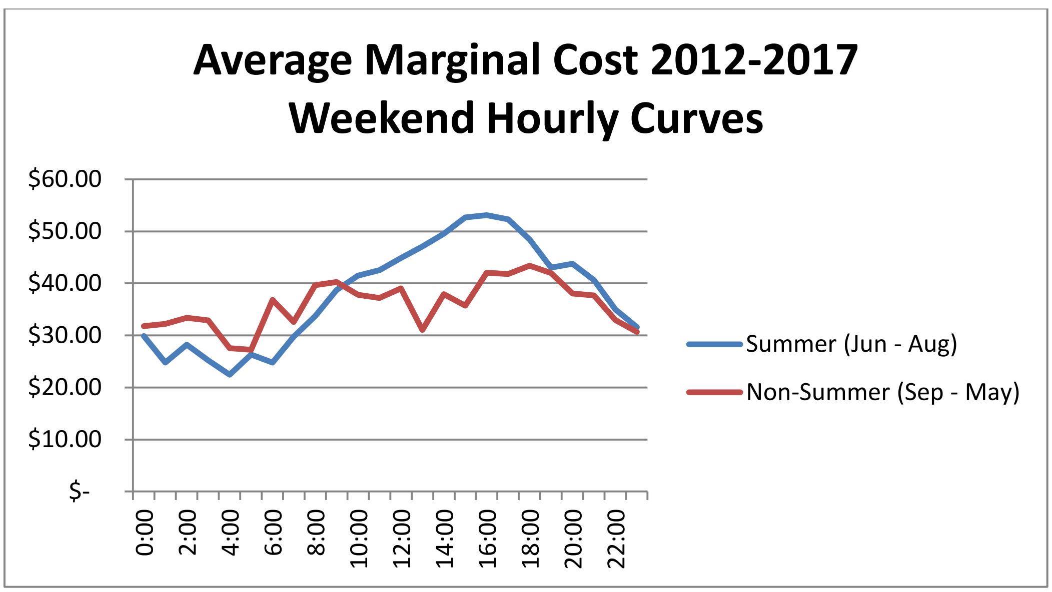


Figure 8b: Weekend (Saturday–Sunday) Average Hourly Marginal Cost, Separated by Season



Hourly marginal cost data supporting these figures is provided in the confidential workpaper file as Table 3. Because this information is confidential it will be provided under separate cover in accordance with Protective Order No. 09-147 issued in this docket.

IV. Fixed Cost of Service

As described on page 10, lines 21-23, of the Company's reply comments filed in this docket on October 20, 2011, "the [Company's] class cost of service model is not currently equipped to provide greater time variant cost data for capacity-related costs and other fixed cost components." Although Idaho Power is unable to provide fixed costs of service on an hourly basis, the Company does have available monthly fixed costs of service for the generation and transmission functional categories. These time-differentiated fixed costs of service are developed using forecast monthly resource surpluses/deficiencies, which are determined in the Company's Integrated Resource Plan ("IRP") analysis. The Company has produced these monthly fixed costs of service as part of its class cost of service studies filed in past general rate cases.

Figure 9, attached to this document, contains monthly peak hour surplus/deficiency data from the Company's most recent class cost of service study filed in Docket UE 233. This workpaper indicates the months during which the Company's supply position is at either a surplus or deficit with respect to each month's peak load hour. The Company currently utilizes this data in the cost allocation and rate setting process as one of the factors considered in determining potential seasonal rate differentiations.

V. Conclusion

The data presented in this report is intended to provide the Commission with information regarding the cost of serving Idaho Power's customers at various times throughout the year, on a seasonal, monthly, and time-of-day basis. The Company looks forward to discussing potential rate structures with Staff as directed in ordering paragraph 3 of Order No. 12-159, and hopes that the data presented herein will serve as a solid foundation for evaluating the merits of these time variant rate structures.

Please contact Scott Wright, (208) 388-5493, swright@idahopower.com, or Matt Larkin, (208) 388-2461, mlarkin@idahopower.com, with questions regarding this information.

IDAHO POWER COMPANY
2011 Marginal Cost Analysis
Generation and Transmission Capacity Cost Allocation Factors Workpaper

A. Generation & Transmission Relating to Integration of 2011 IRP Resources

I 90% Water, 70% Load - - Monthly Peak-hour Surplus / Deficiency Existing and Committed Resources - - 2011 IRP, Technical Appendix

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	191	208	558	878	115	-82	-137	-15	-297	504	318	-125
2012	205	227	573	909	83	-233	8	162	-49	793	625	211
2013	519	543	882	1234	359	-6	-154	15	-100	768	609	196
2014	457	497	836	1184	301	-86	-240	-71	-168	727	559	116
2015	415	464	801	1153	245	-155	-236	-144	-233	690	519	61

II Computation of Five Year Average Monthly Share of Total Deficiencies

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2011		0	0	0	0	0	-82	-137	-15	-297	0	0	-125	
2012		0	0	0	0	0	-233	0	0	-49	0	0	0	
2013		0	0	0	0	0	-6	-154	0	-100	0	0	0	
2014		0	0	0	0	0	-86	-240	-71	-168	0	0	0	
2015		0	0	0	0	0	-155	-236	-144	-233	0	0	0	
Average 2011 - 2015		0	0	0	0	0	-112	-153	-46	-169	0	0	-25	-506
% of Average	**-506**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**22.20%**	**30.30%**	**9.13%**	**33.45%**	**0.00%**	**0.00%**	**4.93%**	**100.00%**

III Monthly Values

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
0.00%	0.00%	0.00%	0.00%	0.00%	22.20%	30.30%	9.13%	33.45%	0.00%	0.00%	4.93%	100.00%

B. Planned System Expansion

Monthly Peak Hour Loads (70th Percentile) 2011 IRP Technical Appendix

Generation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Sum
2011	2553	2440	2147	1901	2863	3047	3185	2930	3019	2068	2231	2815	31198
2015	2661	2517	2236	1958	3067	3364	3533	3222	3277	2203	2353	2948	33338
Growth	107.60	76.52	89.83	57.28	203.74	317.58	348.31	292.36	257.72	134.85	121 11	132.76	2,139.64
Percent of Total	5.03%	3.58%	4.20%	2.68%	9.52%	14.84%	16.28%	13.66%	12.04%	6.30%	5.66%	6.20%	100.00%

Five year peak growth (2011 - 2015): 348

Transmission	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Sum
2011	2553	2440	2147	1901	2863	3047	3185	2930	3019	2068	2231	2815	31198
2020	2781	2595	2328	2026	3276	3632	3839	3498	3532	2307	2462	3121	35396
Growth	227 19	155.22	181.23	125.20	412.87	585.02	654.26	567 55	512.89	239.31	230.35	306.53	4,197.62
Percent of Total	5.41%	3.70%	4.32%	2.98%	9.84%	13.94%	15.59%	13.52%	12.22%	5.70%	5.49%	7.30%	100.00%

Ten year peak growth (2011 - 2020): 654