June 2015

IDAHO POWER®
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APPENDIX C
Technical Report

Integrated Resource Plan 2015

SAFE HARBOR STATEMENT

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.

June 2015

APPENDIX C
Technical Report

Integrated Resource Plan 2015

ACKNOWLEDGMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the *2015 Integrated Resource Plan*. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the Integrated Resource Plan. The Idaho Power team is comprised of individuals that represent many different departments within the company. The Integrated Resource Plan team members are responsible for preparing forecasts, working with the advisory council and the public, and performing all the analyses necessary to prepare the resource plan.

Idaho Power looks forward to continuing the resource planning process with customers, public interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at www.idahopower.com.

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INTRODUCTION

Appendix C–Technical Appendix contains supporting data and explanatory materials used to develop Idaho Power's *2015 Integrated Resource Plan* (IRP).

The main document, the IRP, contains a full narrative of Idaho Power's resource planning process. Additional information regarding the 2015 IRP sales and load forecast is contained in *Appendix A–Sales and Load Forecast*, and details on Idaho Power's demand-side management efforts are explained in *Appendix B–Demand-Side Management 2014 Annual Report*. The IRP, including the three appendices, was filed with the Idaho and Oregon public utility commissions in June 2015.

For information or questions concerning the resource plan or the resource planning process, contact Idaho Power:

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IRP ADVISORY COUNCIL AND MEMBERS

Idaho Power has involved representatives of the public in the IRP planning process since the early 1990s. This public forum has come to be known as the IRP Advisory Council (IRPAC). The IRPAC generally meets monthly during the development of the IRP and the meetings are open to the public. Members of the council include political, environmental, and customer representatives, as well as representatives of other public-interest groups.

As part of preparing the 2015 IRP, Idaho Power hosted a field trip to the Swan Falls hydroelectric project and museum.. Idaho Power also hosted 12 IRPAC meetings, including a resource portfolio design workshop. Idaho Power and members from the IRPAC also met in several small break-out sessions to discuss certain topics in greater detail. Idaho Power values these opportunities to convene, and the IRPAC members and the public have made significant contributions to this plan.

Idaho Power believes working with members of the IRPAC and the public is very rewarding, and the IRP is better because of the public involvement. Idaho Power and the members of the IRPAC recognize that outside perspective is valuable, but also recognize that final decisions on the IRP are made by Idaho Power.

Customer Representatives

Agricultural Representative.....Sid Erwin
Boise State University.....Barry Burbank
Glanbia.....Jim Bergin
Idaho National Laboratory.....Kurt Myers
Micron.....Clancy Kelley
Simplot.....Don Sturtevant/Don Strickler

Public Interest Representatives

Boise Metro Chamber of Commerce.....Ray Stark
Idaho Conservation League.....Ben Otto
Idaho Department of Commerce.....Chrissy Bowers
Idaho Legislature.....Representative Robert Anderst
Idaho Office of Energy Resources.....John Chatburn
Idaho Technology Council.....Jay Larsen
Northwest Power and Conservation Council.....Shirley Lindstrom/Jim Yost
Oil and Gas Industry Advisor.....David Hawk
Oregon State University – Malheur Experiment Station.....Clint Shock
Snake River Alliance.....Ken Miller
University of Idaho Center for Ecohydraulics Research.....Daniele Tonina
University of Idaho Integrated Design Lab.....Kevin Van Den Wymelenberg
Water Issues Advisor.....Vince Alberdi

Regulatory Commission Representatives

Idaho Public Utilities Commission.....Stacey Donohue
Public Utility Commission of Oregon.....Michael Breish

IRP Advisory Council Meeting Schedule and Agenda

Meeting Dates		Agenda Items
2014	Thursday, August 7	Introductions/meeting overview Welcome and opening remarks IRP process explanation System load and operation Demand response update Natural gas forecast Solar workgroup recap
2014	Thursday, September 4	Review of August IRPAC meeting Solar workgroup recap Coal study workgroup recap Natural gas forecast Overview of Idaho Power generation and transmission Resource stack introduction
2014	Wednesday, October 1	Field trip to Swan Falls hydroelectric project and museum
2014	Thursday, October 2	Review of September IRPAC meeting 2015 IRP load forecast Resource stack capital costs IRP risk factors
2014	Thursday, November 6	Review of October IRPAC meeting Coal study Demand-side management Water supply forecast Cloud seeding Hydro generation forecast
2014	Thursday, December 4	Review of November IRPAC meeting Recap of DSM working group meeting Clean Air Act Section 111(d) 500-kV transmission projects Power markets
2015	Thursday, January 8	Review of December IRPAC meeting Recap of DSM working group meetings Energy efficiency potential study final results PURPA/PPA forecast Resource stack
2015	Wednesday, January 28	Portfolio design workshop
2015	Thursday, February 5	Review of January IRPAC meeting AURORA overview Load and resource balance Portfolio design
2015	Thursday, March 12	Review of February IRPAC meeting Conservation voltage reduction update 2015 IRP resource portfolios Portfolio analysis overview

Meeting Dates		Agenda Items
2015	Thursday, April 2	Review of March IRPAC meeting Portfolio analysis results Sustainability at Idaho Power Hells Canyon Complex relicensing
2015	Thursday, May 7	Review of April IRPAC meeting Clean Air Act Section 111(d) sensitivity analysis Stochastic risk analysis Asset replacement deferment End of feeder solar project Flexibility analysis Operational impacts of oversupply
2015	Thursday, June 4	Review of May IRPAC meeting Preferred portfolio discussion Tipping point analysis Natural gas outlook from Potential Gas Committee Shoshone Falls expansion Loss of load expectation analysis 2015 IRP action plan Input for the 2017 IRP and public process

PUBLIC POLICY ISSUES

Clean Air Act Section 111(d) Sensitivities Assumptions

Section 111(d) Sensitivities

Because of the uncertainty associated with the EPA's proposed regulation of CO_2 under the *Clean Air Act of 1970* (CAA) Section 111(d), a range of sensitivities was modeled. Each sensitivity is based on multiple assumptions as provided in this section. It is noted that portfolio cost results associated with each sensitivity are contingent upon underlying assumptions of the sensitivity; stipulations for the final CAA Section 111(d) regulation may differ greatly from those assumed for these sensitivities, leading possibly to markedly different costs in practice.

Null Sensitivity (No CAA Section 111(d))

- No existing regulations require any modifications to operations or equipment
- No pending or future regulations (i.e., CAA Section 111(d)) will require any modifications to operations or equipment
- Analyzed to provide a comparison with portfolios complying with CAA Section 111(d)-based regulations on CO_2 emissions

State-by-State Mass-Based Compliance

- Compliance determined within state boundaries
- Compliance cannot cross state lines and plant reductions cannot be shifted across state lines
- Converting from rate base to mass base using percent reduction from rate goals established by proposed regulation
- No requirements for renewable energy or energy efficiency
- Generation is capped at the target levels
    - North Valmy targets—574,382 MWh/year for 2020-2029 and 533,343 MWh/year for 2030 through IRP planning period end
    - Jim Bridger targets—3,914,502 MWh/year for 2020-2029 and 3,675,608 MWh/year for 2030 through IRP planning period end
    - Langley Gulch target alternatives
        - 30 percent annual capacity factor for 2020 through IRP planning period end (837,018 MWh/year)
        - 55 percent annual capacity factor for 2020 through IRP planning period end (1,534,533 MWh/year)
        - 70 percent annual capacity factor for 2020 through IRP planning period end (1,953,042 MWh/year)

System-Wide Mass-Based Compliance

- Determine total CO_2 reduction for Idaho Power system
- Compliance is determined by meeting Idaho Power system CO_2 emission target
- Compliance can cross state lines and plant CO_2 reductions can be shifted across state lines
- Converting from rate base to mass base using percent reduction from rate goals established by proposed regulation
- No requirements for renewable energy or energy efficiency
- Idaho Power system emissions are capped at the target levels
    - 6,332,020 tons CO_2 for 2020–2029
    - 5,925,874 tons CO_2 for 2030 through IRP planning period end
- Early shutdown of units enables other units to increase generation

Emissions Intensity Compliance Utilizing the EPA's Compliance Building Blocks

- All building blocks required to meet compliance
- Rate reductions established based on the goal calculations by the EPA
- The state of Idaho is able to count previously constructed PURPA projects as part of building block 3
- Renewable energy (building block 3) and energy efficiency (building block 4) in Idaho grow to EPA projected levels
- No renewable energy or energy efficiency requirements for states where Idaho Power has no customers (Wyoming, Nevada)
- CAA Section 111(d) CO_2 attributes can cross state lines
- Affected unit generation and renewable energy/energy efficiency are variable as long as interim and final rates are met
- Idaho Power is not responsible for meeting interim or final goals for Wyoming, Nevada, or Oregon
- Since Boardman has an agreed upon closure date, Idaho Power has no rate requirements to meet in Oregon
- Interim goals are relaxed with agreed upon retirement dates for Boardman and North Valmy set at 2020 and 2025 respectively (note that pre-2025 North Valmy retirement also allows a relaxing of interim goals)
- Building block 1 (6 percent efficiency improvement) cannot be met or sustained and is reset to 0 percent
- Jim Bridger generation reduced from 2012 levels for pro-rata share of 95 MW natural gas plant under construction in Wyoming (building block 2)
- Generation capped at the target levels
    - North Valmy target—814,264 MWh/year until retirement (retirement no later than 2025)

- Jim Bridger target—4,488,392 MW/year for 2020 through IRP planning period end
- Langley Gulch target alternatives
  - 30 percent annual capacity factor for 2020 through IRP planning period end (837,018 MWh/year)
  - 55 percent annual capacity factor for 2020 through IRP planning period end (1,534,533 MWh/year)
  - 70 percent annual capacity factor for 2020 through IRP planning period end (1,953,042 MWh/year)

Flow Modeling

Models

Idaho Power uses two primary models for forecasting future flows for the IRP. The Snake River Planning Model (SRPM) is used to forecast surface water flows and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to forecast the impact of various aquifer management practices implemented on the Eastern Snake Plain Aquifer (ESPA). The SRPM was updated in late 2012 to include hydrologic conditions for years 1928 through 2009. ESPAM was also updated with the release of ESPAM 2.1 in late 2012. Beginning with the 2009 IRP, Idaho Power began running the SRPM and ESPAM as a combined modeling system. The combined model seeks to maximize diversions for aquifer recharge and system conversions without creating additional model irrigation shortages over a modeled reference condition.

Model Inputs

The model inputs used in this effort are similar to the inputs used in the 2011 and 2013 IRP but those inputs continued to be refined to reflect future system conditions and management policies. The general inputs to the model are reach declines, weather modification, aquifer recharge, system conversions, and retirement of land from irrigation.

Future reach declines were determined using a variety of statistical analysis. Trend data indicate reach gains into American Falls Reservoir and from Milner Dam to Lower Salmon Falls Dam demonstrated a statistically significant decline for the period of 1980 to 2013. Reach gains into American Falls Reservoir declined on average 23 cubic feet per second per month (cfs/month) with declines ranging from 12 to 34 cfs/month. Reach gains from Milner Dam to Lower Salmon Falls Dam for American declined on average 34 cubic feet per second per month (cfs/month) with declines ranging from 22 to 53 cfs/month. Declines in these two reaches met strict, predefined criteria and were therefore included as inputs into the model.

Weather modification was added to the model at different levels of development. For IRP years 2015 through 2019, weather modification was increased to reflect projected levels of fully built-out programs in Eastern Idaho, the Wood River Valley, and the Boise Basin. Beyond IRP year 2019, weather modification levels in these three basins were held constant through the rest of the IRP forecast period. The level of weather modification was held constant at the current level in the Payette River Basin throughout the IRP forecast period. The amount of weather modification added to each year is

based on the total runoff for each year from 1928 through 2009. At full build out the Payette basin increase total discharge by an average of 271,567 acre-ft/year. The Upper Snake, Wood River, and Boise Basins, respectively, add an average of 453,130 acre-ft/year; 108,900 acre-ft/year; and 218,249 acre-ft/year by IRP year 2019.

Aquifer recharge was added to the model at levels reflected in the 2014 Idaho Water Resource Board Preliminary Draft—Managed Recharge Plan. In the 2015 IRP, recharge expanded to include wintertime recharge from winter time diversions at Milner Dam. Recharge peaks in IRP year 2021 at approximately 209,839 acre-ft and then slowly declines as diminishing reach gains limit the amount of water available for aquifer recharge.

System conversion projects involve the conversion of ground water supplied irrigated land to surface supplied irrigated land. The number of acres modeled and potential water savings was based on data provided by the Idaho Department of Water Resources (IDWR). The current model assumes a total of 14,767 acres of converted land on the ESPA with a total water savings of 2.0 acre-ft or water per acre of irrigated land (acre-ft/ac). Additional conversion projects are added to the model and from 2020 to 2034 they are held constant at 16,687 acres. Diversions for conversion projects are limited by water availability to meet the demand. Diversions for conversion projects peak in 2020 at 32,440 acre-ft. Diversions for conversion project generally declines after 2020 at declines in reach gains reduces water availability for diversion.

The model accounts for approximately 15,140 acres that are currently in the Conservation Reserve Enhancement Program (CREP). These acres are idled under a 15-year contract with the U.S. Department of Agriculture. Each idled acre is credited in the ESPAM model for reducing irrigation withdrawal from the ESPA by 2.0 acre-ft/year. Many of the CREP contracts were initiated in 2006 and are set to retire beginning in 2020. The current model phases out CREP acres over a four-year period and includes no idled acres by IRP year 2024. The reduction in CREP acres further results in reducing the amount of water available for other management activities such as aquifer recharge and system conversions. Also included in this model run are 750 acres of short-term projects to reduce water use by ground water appropriators. The projects may include the elimination of end gun on center pivots or drying pivot corners. These short-term projects run from 2015 to 2023.

Model Results

The combined model allows for the ability to include future management activities, and the resulting reach gains from those management activities into Idaho Power's 2015 IRP. Management activities, such as recharge and system conversions, do not significantly change the total annual volume of water expected to flow through the Hells Canyon Complex, but instead change the timing and location of reach gains within the system. Other future management activities, such as weather modification and CREP do directly impact the annual volume of water expected through the Hells Canyon Complex as well as the timing and location of gains within the system.

Overall flow through the Hells Canyon Complex increases from IRP year 2015 through 2019 in response to increased weather modification in the Upper Snake, Wood and Boise River Basins. Flows peak in 2019 with the 50 percent exceedance flows into Brownlee Reservoir as just over 11.9 million acre-ft/year. In 2034, those flows have declined to approximately 11.3 million acre-ft/year,

with most of the declines attributable to declining flows into American Falls and the Milner to Lower Salmon Falls reach.

2015 Model Parameters

IRP Year	Managed Recharge (acft/yr)			Weather Modification (acft/yr)	System Conversions (Ac)	CREP (Ac)	Reach Declines (acft/yr)	
	Above American Falls	Below American Falls	Total				American Falls Inflows	Below Milner Inflows
2015	34,060	29,793	63,852	715,209	14,767	15,890	102,644	152,147
2016	33,896	29,772	63,668	840,784	14,767	15,890	119,751	177,504
2017	34,339	69,965	104,304	960,948	14,767	15,890	136,858	202,862
2018	35,417	94,061	129,478	1,017,289	15,407	15,890	153,966	228,220
2019	43,433	168,533	211,966	1,051,936	16,047	15,890	171,073	253,578
2020	42,926	167,127	210,052	1,051,936	16,687	12,033	188,180	278,936
2021	42,989	166,850	209,839	1,051,936	16,687	8,312	205,287	304,293
2022	42,795	166,640	209,435	1,051,936	16,687	4,531	222,395	329,651
2023	42,599	166,983	209,582	1,051,936	16,687	2,056	239,502	355,009
2024	42,265	164,705	206,970	1,051,936	16,687	0	256,609	380,367
2025	42,272	164,293	206,565	1,051,936	16,687	0	273,717	405,724
2026	42,271	163,541	205,812	1,051,936	16,687	0	290,824	431,082
2027	42,021	162,395	204,416	1,051,936	16,687	0	307,931	456,440
2028	42,240	162,839	205,079	1,051,936	16,687	0	325,039	481,798
2029	42,389	163,178	205,567	1,051,936	16,687	0	342,146	507,156
2030	42,129	162,217	204,346	1,051,936	16,687	0	359,253	532,513
2031	41,716	161,734	203,450	1,051,936	16,687	0	376,360	557,871
2032	41,715	161,600	203,315	1,051,936	16,687	0	393,468	583,229
2033	41,887	161,659	203,545	1,051,936	16,687	0	410,575	608,587
2034	42,189	163,380	205,570	1,051,936	16,687	0	427,682	633,944

SALES AND LOAD FORECAST DATA

Average Annual Forecast Growth Rates

	2015–2020	2015–2025	2015–2034
Sales			
Residential Sales	1.57%	1.40%	1.33%
Commercial Sales	1.02%	1.00%	0.98%
Irrigation Sales	0.62%	0.51%	0.49%
Industrial Sales	2.91%	2.36%	1.99%
Additional Firm Sales	0.89%	1.35%	0.64%
System Sales	1.48%	1.34%	1.20%
Total Sales	1.48%	1.34%	1.20%
Loads			
Residential Load	1.56%	1.40%	1.32%
Commercial Load	1.02%	0.99%	0.98%
Irrigation Load	0.56%	0.51%	0.49%
Industrial Load	2.78%	2.32%	1.97%
Additional Firm Sales	0.89%	1.35%	0.64%
System Load Losses	1.37%	1.25%	1.16%
System Load	1.43%	1.32%	1.19%
Total Load	1.43%	1.32%	1.19%
Peaks			
System Peak	1.78%	1.66%	1.53%
Total Peak	1.78%	1.66%	1.53%
Winter Peak	0.91%	0.93%	0.88%
Summer Peak	1.78%	1.66%	1.53%
Customers			
Residential Customers	2.13%	1.88%	1.62%
Commercial Customers	2.03%	1.91%	1.72%
Irrigation Customers	1.40%	1.35%	1.28%
Industrial Customers	0.53%	0.69%	0.66%

Expected-Case Load Forecast

Monthly Summary[1]	1/2015	2/2015	3/2015	4/2015	5/2015	6/2015	7/2015	8/2015	9/2015	10/2015	11/2015	12/2015
Average Load (aMW)–50th Percentile												
Residential	753	705	609	510	440	462	669	543	457	481	590	843
Commercial	482	470	446	433	428	454	534	475	461	453	448	503
Irrigation	2	2	5	89	302	536	659	544	311	77	5	3
Industrial	277	274	276	262	256	281	279	282	279	288	283	285
Additional Firm	105	103	99	101	95	100	98	98	101	100	104	103
Loss	139	133	122	119	131	160	199	171	138	118	121	150
System Load	**1,759**	**1,688**	**1,556**	**1,513**	**1,652**	**1,994**	**2,438**	**2,113**	**1,747**	**1,517**	**1,551**	**1,887**
Light Load	1,634	1,551	1,421	1,369	1,493	1,801	2,206	1,870	1,557	1,365	1,429	1,741
Heavy Load	1,858	1,791	1,663	1,618	1,790	2,135	2,621	2,304	1,898	1,627	1,658	2,002
Total Load	**1,759**	**1,688**	**1,556**	**1,513**	**1,652**	**1,994**	**2,438**	**2,113**	**1,747**	**1,517**	**1,551**	**1,887**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,264	2,342	2,072	2,017	2,649	3,109	3,537	2,995	2,887	2,117	2,170	2,603
Total Peak Load	**2,264**	**2,342**	**2,072**	**2,017**	**2,649**	**3,109**	**3,537**	**2,995**	**2,887**	**2,117**	**2,170**	**2,603**

Monthly Summary[1]	1/2016	2/2016	3/2016	4/2016	5/2016	6/2016	7/2016	8/2016	9/2016	10/2016	11/2016	12/2016
Average Load (aMW)–50th Percentile												
Residential	771	721	623	521	451	475	688	558	468	492	603	860
Commercial	490	477	453	440	435	462	543	483	469	461	456	509
Irrigation	2	2	5	90	308	547	673	556	317	79	5	3
Industrial	296	283	294	279	273	300	297	301	298	307	302	293
Additional Firm	110	105	105	104	97	94	101	101	99	101	105	109
Loss	143	136	125	122	135	164	204	175	142	121	124	153
System Load	**1,813**	**1,724**	**1,605**	**1,557**	**1,700**	**2,042**	**2,507**	**2,175**	**1,794**	**1,561**	**1,594**	**1,927**
Light Load	1,683	1,584	1,466	1,409	1,536	1,844	2,268	1,924	1,600	1,404	1,469	1,778
Heavy Load	1,924	1,828	1,706	1,666	1,841	2,186	2,712	2,355	1,950	1,684	1,695	2,044
Total Load	**1,813**	**1,724**	**1,605**	**1,557**	**1,700**	**2,042**	**2,507**	**2,175**	**1,794**	**1,561**	**1,594**	**1,927**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,334	2,378	2,125	2,072	2,714	3,211	3,630	3,087	2,978	2,167	2,218	2,640
Total Peak Load	**2,334**	**2,378**	**2,125**	**2,072**	**2,714**	**3,211**	**3,630**	**3,087**	**2,978**	**2,167**	**2,218**	**2,640**

Monthly Summary[1]	1/2017	2/2017	3/2017	4/2017	5/2017	6/2017	7/2017	8/2017	9/2017	10/2017	11/2017	12/2017
Average Load (aMW)–50th Percentile												
Residential	785	733	634	531	460	485	704	571	478	500	613	873
Commercial	495	481	457	444	439	466	547	488	474	466	460	514
Irrigation	2	2	5	91	311	551	678	560	320	79	5	3
Industrial	304	300	302	287	280	308	305	309	306	315	310	299
Additional Firm	111	110	106	105	97	94	102	102	100	101	105	109
Loss	145	139	127	123	137	166	207	178	144	123	126	155
System Load	1,842	1,765	1,630	1,581	1,725	2,071	2,543	2,207	1,822	1,585	1,619	1,953
Light Load	1,710	1,621	1,489	1,431	1,558	1,871	2,301	1,953	1,624	1,426	1,492	1,802
Heavy Load	1,955	1,872	1,732	1,701	1,856	2,217	2,752	2,390	1,980	1,710	1,722	2,082
Total Load	1,842	1,765	1,630	1,581	1,725	2,071	2,543	2,207	1,822	1,585	1,619	1,953
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,360	2,414	2,148	2,093	2,755	3,266	3,696	3,137	3,027	2,193	2,242	2,664
Total Peak Load	2,360	2,414	2,148	2,093	2,755	3,266	3,696	3,137	3,027	2,193	2,242	2,664

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2018	2/2018	3/2018	4/2018	5/2018	6/2018	7/2018	8/2018	9/2018	10/2018	11/2018	12/2018
Average Load (aMW)–50th Percentile												
Residential	794	741	641	537	467	493	715	580	485	506	620	884
Commercial	498	483	459	447	442	470	551	492	478	469	463	518
Irrigation	2	2	5	91	311	552	679	560	320	79	5	3
Industrial	309	306	308	292	286	314	311	315	312	321	316	304
Additional Firm	112	110	106	105	98	94	102	102	100	102	106	110
Loss	147	140	129	125	138	168	209	179	146	124	127	157
System Load	**1,863**	**1,783**	**1,647**	**1,597**	**1,741**	**2,090**	**2,568**	**2,228**	**1,841**	**1,602**	**1,637**	**1,975**
Light Load	1,730	1,638	1,504	1,445	1,573	1,888	2,323	1,972	1,641	1,441	1,508	1,823
Heavy Load	1,968	1,892	1,750	1,719	1,874	2,238	2,778	2,413	2,015	1,718	1,740	2,106
Total Load	**1,863**	**1,783**	**1,647**	**1,597**	**1,741**	**2,090**	**2,568**	**2,228**	**1,841**	**1,602**	**1,637**	**1,975**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,367	2,425	2,157	2,099	2,786	3,302	3,752	3,170	3,062	2,212	2,250	2,681
Total Peak Load	**2,367**	**2,425**	**2,157**	**2,099**	**2,786**	**3,302**	**3,752**	**3,170**	**3,062**	**2,212**	**2,250**	**2,681**

Monthly Summary[1]	1/2019	2/2019	3/2019	4/2019	5/2019	6/2019	7/2019	8/2019	9/2019	10/2019	11/2019	12/2019
Average Load (aMW)–50th Percentile												
Residential	803	748	647	543	473	500	727	589	492	511	626	893
Commercial	502	487	462	450	446	474	556	496	483	473	467	523
Irrigation	2	2	5	91	310	551	677	559	319	79	5	3
Industrial	315	311	313	297	291	319	316	320	317	327	321	309
Additional Firm	112	110	106	105	98	94	102	102	100	102	106	110
Loss	149	142	130	126	139	169	211	181	147	126	129	159
System Load	**1,883**	**1,800**	**1,664**	**1,612**	**1,756**	**2,107**	**2,589**	**2,247**	**1,858**	**1,618**	**1,654**	**1,996**
Light Load	1,748	1,654	1,519	1,459	1,587	1,903	2,342	1,989	1,656	1,455	1,523	1,842
Heavy Load	1,989	1,910	1,777	1,725	1,890	2,270	2,783	2,434	2,034	1,735	1,758	2,128
Total Load	**1,883**	**1,800**	**1,664**	**1,612**	**1,756**	**2,107**	**2,589**	**2,247**	**1,858**	**1,618**	**1,654**	**1,996**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,514	2,388	2,072	1,992	2,950	3,362	3,555	3,161	2,907	2,090	2,260	2,668
Total Peak Load	**2,514**	**2,388**	**2,072**	**1,992**	**2,950**	**3,362**	**3,555**	**3,161**	**2,907**	**2,090**	**2,260**	**2,668**

Monthly Summary[1]	1/2020	2/2020	3/2020	4/2020	5/2020	6/2020	7/2020	8/2020	9/2020	10/2020	11/2020	12/2020
Average Load (aMW)–50th Percentile												
Residential	810	753	652	547	477	505	735	596	497	515	630	901
Commercial	507	490	466	454	450	479	561	501	488	478	471	528
Irrigation	2	2	5	92	312	554	681	562	321	80	5	3
Industrial	320	306	318	302	296	325	322	326	322	332	327	315
Additional Firm	113	108	107	107	99	96	103	103	101	103	107	111
Loss	150	142	131	127	140	171	213	183	149	127	130	161
System Load	**1,902**	**1,801**	**1,680**	**1,628**	**1,774**	**2,129**	**2,615**	**2,271**	**1,878**	**1,634**	**1,670**	**2,019**
Light Load	1,766	1,655	1,534	1,473	1,603	1,923	2,366	2,009	1,674	1,470	1,539	1,863
Heavy Load	2,009	1,909	1,794	1,742	1,921	2,279	2,811	2,477	2,041	1,753	1,786	2,142
Total Load	**1,902**	**1,801**	**1,680**	**1,628**	**1,774**	**2,129**	**2,615**	**2,271**	**1,878**	**1,634**	**1,670**	**2,019**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,414	2,457	2,193	2,135	2,848	3,372	3,862	3,236	3,129	2,248	2,288	2,725
Total Peak Load	**2,414**	**2,457**	**2,193**	**2,135**	**2,848**	**3,372**	**3,862**	**3,236**	**3,129**	**2,248**	**2,288**	**2,725**

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2021	2/2021	3/2021	4/2021	5/2021	6/2021	7/2021	8/2021	9/2021	10/2021	11/2021	12/2021
Average Load (aMW)–50th Percentile												
Residential	818	759	658	552	483	512	746	604	503	520	636	911
Commercial	512	494	470	458	455	483	566	506	494	482	476	534
Irrigation	2	2	5	92	314	557	685	566	323	80	5	3
Industrial	326	323	324	308	301	331	328	332	328	338	333	320
Additional Firm	113	112	108	107	99	96	103	103	101	103	107	112
Loss	152	144	132	128	142	173	215	185	150	128	131	162
System Load	**1,923**	**1,834**	**1,697**	**1,645**	**1,793**	**2,152**	**2,643**	**2,296**	**1,899**	**1,652**	**1,688**	**2,041**
Light Load	1,785	1,685	1,550	1,489	1,620	1,944	2,391	2,032	1,693	1,486	1,555	1,884
Heavy Load	2,041	1,946	1,803	1,760	1,942	2,304	2,842	2,504	2,064	1,782	1,795	2,166
Total Load	**1,923**	**1,834**	**1,697**	**1,645**	**1,793**	**2,152**	**2,643**	**2,296**	**1,899**	**1,652**	**1,688**	**2,041**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,429	2,473	2,207	2,148	2,882	3,415	3,922	3,275	3,168	2,268	2,302	2,744
Total Peak Load	**2,429**	**2,473**	**2,207**	**2,148**	**2,882**	**3,415**	**3,922**	**3,275**	**3,168**	**2,268**	**2,302**	**2,744**

Monthly Summary[1]	1/2022	2/2022	3/2022	4/2022	5/2022	6/2022	7/2022	8/2022	9/2022	10/2022	11/2022	12/2022
Average Load (aMW)–50th Percentile												
Residential	825	765	663	557	488	518	756	612	508	524	641	920
Commercial	516	498	474	462	459	488	571	511	499	487	480	539
Irrigation	2	2	5	92	315	559	687	567	324	80	5	3
Industrial	332	329	330	314	307	337	334	338	334	345	339	326
Additional Firm	119	117	112	111	102	99	106	106	104	107	112	117
Loss	153	146	134	130	143	174	217	187	152	129	133	164
System Load	**1,948**	**1,856**	**1,718**	**1,666**	**1,814**	**2,176**	**2,672**	**2,322**	**1,922**	**1,672**	**1,710**	**2,070**
Light Load	1,809	1,705	1,569	1,507	1,639	1,965	2,417	2,055	1,714	1,505	1,575	1,910
Heavy Load	2,067	1,969	1,825	1,781	1,964	2,330	2,890	2,515	2,089	1,805	1,818	2,196
Total Load	**1,948**	**1,856**	**1,718**	**1,666**	**1,814**	**2,176**	**2,672**	**2,322**	**1,922**	**1,672**	**1,710**	**2,070**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,448	2,491	2,225	2,162	2,917	3,456	3,981	3,313	3,207	2,291	2,320	2,770
Total Peak Load	**2,448**	**2,491**	**2,225**	**2,162**	**2,917**	**3,456**	**3,981**	**3,313**	**3,207**	**2,291**	**2,320**	**2,770**

Monthly Summary[1]	1/2023	2/2023	3/2023	4/2023	5/2023	6/2023	7/2023	8/2023	9/2023	10/2023	11/2023	12/2023
Average Load (aMW)–50th Percentile												
Residential	834	772	670	563	494	526	767	622	515	529	647	933
Commercial	521	502	478	466	463	493	576	516	505	492	485	545
Irrigation	2	2	5	92	315	559	688	568	324	81	5	3
Industrial	338	335	336	319	312	343	340	344	340	351	345	332
Additional Firm	123	121	116	114	105	102	109	109	107	110	115	121
Loss	155	147	135	131	145	176	220	188	154	131	134	166
System Load	**1,974**	**1,879**	**1,740**	**1,686**	**1,835**	**2,199**	**2,700**	**2,347**	**1,945**	**1,693**	**1,732**	**2,100**
Light Load	1,833	1,726	1,589	1,526	1,658	1,987	2,443	2,077	1,734	1,524	1,595	1,938
Heavy Load	2,095	1,994	1,848	1,814	1,974	2,355	2,921	2,542	2,114	1,827	1,841	2,239
Total Load	**1,974**	**1,879**	**1,740**	**1,686**	**1,835**	**2,199**	**2,700**	**2,347**	**1,945**	**1,693**	**1,732**	**2,100**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,475	2,514	2,247	2,183	2,953	3,498	4,041	3,352	3,246	2,314	2,343	2,799
Total Peak Load	**2,475**	**2,514**	**2,247**	**2,183**	**2,953**	**3,498**	**4,041**	**3,352**	**3,246**	**2,314**	**2,343**	**2,799**

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2024	2/2024	3/2024	4/2024	5/2024	6/2024	7/2024	8/2024	9/2024	10/2024	11/2024	12/2024
Average Load (aMW)–50th Percentile												
Residential	845	782	678	571	501	535	781	633	523	536	655	946
Commercial	526	506	482	470	468	498	582	521	511	497	490	550
Irrigation	2	2	5	93	317	562	691	571	326	81	5	3
Industrial	344	329	342	325	318	349	346	350	346	357	351	338
Additional Firm	126	119	118	117	107	104	111	111	109	112	118	124
Loss	157	148	137	133	147	178	222	191	155	133	136	169
System Load	**2,001**	**1,886**	**1,762**	**1,708**	**1,857**	**2,226**	**2,733**	**2,376**	**1,970**	**1,715**	**1,755**	**2,130**
Light Load	1,858	1,733	1,609	1,545	1,678	2,011	2,472	2,103	1,757	1,543	1,617	1,966
Heavy Load	2,114	1,999	1,882	1,826	1,999	2,398	2,938	2,574	2,157	1,840	1,866	2,271
Total Load	**2,001**	**1,886**	**1,762**	**1,708**	**1,857**	**2,226**	**2,733**	**2,376**	**1,970**	**1,715**	**1,755**	**2,130**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,507	2,537	2,272	2,208	2,991	3,546	4,105	3,397	3,291	2,338	2,370	2,830
Total Peak Load	**2,507**	**2,537**	**2,272**	**2,208**	**2,991**	**3,546**	**4,105**	**3,397**	**3,291**	**2,338**	**2,370**	**2,830**

Monthly Summary[1]	1/2025	2/2025	3/2025	4/2025	5/2025	6/2025	7/2025	8/2025	9/2025	10/2025	11/2025	12/2025
Average Load (aMW)–50th Percentile												
Residential	857	791	687	578	509	544	795	644	532	543	663	959
Commercial	531	510	486	474	472	504	587	527	516	502	494	556
Irrigation	2	2	5	94	319	566	696	574	328	81	5	3
Industrial	350	347	348	331	323	355	352	357	353	364	358	344
Additional Firm	126	124	118	117	107	104	111	111	109	112	118	124
Loss	159	150	138	134	148	180	225	193	157	134	137	171
System Load	**2,025**	**1,924**	**1,783**	**1,727**	**1,879**	**2,252**	**2,766**	**2,405**	**1,995**	**1,736**	**1,776**	**2,157**
Light Load	1,881	1,768	1,628	1,563	1,698	2,034	2,502	2,129	1,779	1,562	1,636	1,991
Heavy Load	2,140	2,041	1,904	1,847	2,022	2,427	2,973	2,624	2,168	1,861	1,898	2,288
Total Load	**2,025**	**1,924**	**1,783**	**1,727**	**1,879**	**2,252**	**2,766**	**2,405**	**1,995**	**1,736**	**1,776**	**2,157**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,535	2,559	2,294	2,230	3,027	3,594	4,168	3,442	3,335	2,361	2,394	2,857
Total Peak Load	**2,535**	**2,559**	**2,294**	**2,230**	**3,027**	**3,594**	**4,168**	**3,442**	**3,335**	**2,361**	**2,394**	**2,857**

Monthly Summary[1]	1/2026	2/2026	3/2026	4/2026	5/2026	6/2026	7/2026	8/2026	9/2026	10/2026	11/2026	12/2026
Average Load (aMW)–50th Percentile												
Residential	868	801	696	586	517	553	809	655	540	550	671	973
Commercial	536	514	490	478	477	509	593	532	522	507	499	562
Irrigation	2	2	5	94	321	569	700	578	330	82	5	3
Industrial	356	353	354	337	329	362	358	363	359	370	364	350
Additional Firm	126	123	118	116	107	103	111	110	108	112	118	124
Loss	161	152	140	136	150	182	227	195	159	136	139	173
System Load	**2,050**	**1,945**	**1,803**	**1,747**	**1,900**	**2,278**	**2,798**	**2,434**	**2,019**	**1,756**	**1,796**	**2,184**
Light Load	1,903	1,787	1,646	1,581	1,717	2,058	2,532	2,154	1,800	1,580	1,654	2,015
Heavy Load	2,165	2,064	1,926	1,868	2,058	2,439	3,008	2,655	2,194	1,883	1,920	2,317
Total Load	**2,050**	**1,945**	**1,803**	**1,747**	**1,900**	**2,278**	**2,798**	**2,434**	**2,019**	**1,756**	**1,796**	**2,184**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,561	2,578	2,315	2,251	3,064	3,643	4,231	3,486	3,379	2,384	2,416	2,883
Total Peak Load	2,561	2,578	2,315	2,251	3,064	3,643	4,231	3,486	3,379	2,384	2,416	2,883

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2027	2/2027	3/2027	4/2027	5/2027	6/2027	7/2027	8/2027	9/2027	10/2027	11/2027	12/2027
Average Load (aMW)–50th Percentile												
Residential	880	810	704	593	524	562	823	667	548	557	679	987
Commercial	541	518	493	482	481	514	598	537	528	511	504	567
Irrigation	2	2	5	95	323	573	704	581	332	82	5	3
Industrial	363	359	360	342	335	368	364	369	365	376	370	356
Additional Firm	126	123	118	116	107	103	111	110	108	112	118	124
Loss	163	154	141	137	152	184	230	198	161	137	141	175
System Load	**2,074**	**1,966**	**1,823**	**1,766**	**1,922**	**2,304**	**2,830**	**2,462**	**2,043**	**1,776**	**1,816**	**2,211**
Light Load	1,926	1,806	1,664	1,598	1,736	2,081	2,560	2,179	1,821	1,598	1,673	2,041
Heavy Load	2,202	2,086	1,937	1,889	2,081	2,467	3,043	2,686	2,220	1,916	1,931	2,346
Total Load	**2,074**	**1,966**	**1,823**	**1,766**	**1,922**	**2,304**	**2,830**	**2,462**	**2,043**	**1,776**	**1,816**	**2,211**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,587	2,598	2,335	2,271	3,100	3,690	4,293	3,530	3,423	2,406	2,437	2,910
Total Peak Load	**2,587**	**2,598**	**2,335**	**2,271**	**3,100**	**3,690**	**4,293**	**3,530**	**3,423**	**2,406**	**2,437**	**2,910**

Monthly Summary[1]	1/2028	2/2028	3/2028	4/2028	5/2028	6/2028	7/2028	8/2028	9/2028	10/2028	11/2028	12/2028
Average Load (aMW)–50th Percentile												
Residential	892	820	713	601	532	572	838	678	557	564	687	1,000
Commercial	546	522	498	486	486	519	603	542	534	517	508	573
Irrigation	2	2	5	95	324	575	708	584	334	83	5	3
Industrial	369	352	367	348	340	374	371	375	371	383	376	362
Additional Firm	125	118	117	116	106	103	110	110	108	111	117	123
Loss	165	155	143	139	153	186	233	200	163	139	142	178
System Load	**2,098**	**1,969**	**1,843**	**1,785**	**1,943**	**2,329**	**2,862**	**2,490**	**2,067**	**1,796**	**1,837**	**2,239**
Light Load	1,948	1,809	1,683	1,616	1,755	2,104	2,590	2,204	1,843	1,615	1,692	2,066
Heavy Load	2,227	2,088	1,958	1,921	2,090	2,494	3,097	2,697	2,246	1,938	1,953	2,387
Total Load	**2,098**	**1,969**	**1,843**	**1,785**	**1,943**	**2,329**	**2,862**	**2,490**	**2,067**	**1,796**	**1,837**	**2,239**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,615	2,617	2,357	2,293	3,137	3,738	4,355	3,574	3,466	2,428	2,460	2,937
Total Peak Load	**2,615**	**2,617**	**2,357**	**2,293**	**3,137**	**3,738**	**4,355**	**3,574**	**3,466**	**2,428**	**2,460**	**2,937**

Monthly Summary[1]	1/2029	2/2029	3/2029	4/2029	5/2029	6/2029	7/2029	8/2029	9/2029	10/2029	11/2029	12/2029
Average Load (aMW)–50th Percentile												
Residential	904	830	722	609	540	581	852	690	566	571	696	1,013
Commercial	551	526	502	491	491	524	609	548	540	522	513	579
Irrigation	2	2	5	96	326	579	712	588	336	83	5	3
Industrial	375	371	373	354	346	381	377	382	378	389	383	367
Additional Firm	125	123	117	116	106	103	110	110	108	111	117	123
Loss	167	157	145	140	155	188	235	202	165	140	144	180
System Load	**2,124**	**2,009**	**1,864**	**1,806**	**1,965**	**2,356**	**2,896**	**2,520**	**2,092**	**1,817**	**1,858**	**2,265**
Light Load	1,972	1,846	1,702	1,634	1,775	2,128	2,620	2,230	1,865	1,634	1,712	2,090
Heavy Load	2,244	2,131	1,980	1,943	2,114	2,523	3,133	2,730	2,291	1,948	1,976	2,415
Total Load	**2,124**	**2,009**	**1,864**	**1,806**	**1,965**	**2,356**	**2,896**	**2,520**	**2,092**	**1,817**	**1,858**	**2,265**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,642	2,638	2,378	2,314	3,174	3,788	4,419	3,621	3,512	2,452	2,483	2,963
Total Peak Load	**2,642**	**2,638**	**2,378**	**2,314**	**3,174**	**3,788**	**4,419**	**3,621**	**3,512**	**2,452**	**2,483**	**2,963**

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2030	2/2030	3/2030	4/2030	5/2030	6/2030	7/2030	8/2030	9/2030	10/2030	11/2030	12/2030
Average Load (aMW)–50th Percentile												
Residential	914	838	729	616	547	589	865	701	573	577	702	1,024
Commercial	556	530	506	495	496	530	615	554	546	527	518	585
Irrigation	2	2	5	96	328	582	716	591	338	84	5	3
Industrial	381	377	379	360	352	387	383	388	384	395	389	373
Additional Firm	126	123	118	116	107	103	111	110	108	112	118	124
Loss	169	159	146	142	157	190	238	205	167	142	145	182
System Load	**2,147**	**2,029**	**1,883**	**1,825**	**1,986**	**2,381**	**2,927**	**2,548**	**2,115**	**1,836**	**1,878**	**2,290**
Light Load	1,994	1,864	1,720	1,651	1,794	2,151	2,648	2,255	1,886	1,652	1,730	2,113
Heavy Load	2,268	2,153	2,012	1,951	2,137	2,565	3,147	2,759	2,316	1,969	1,997	2,442
Total Load	**2,147**	**2,029**	**1,883**	**1,825**	**1,986**	**2,381**	**2,927**	**2,548**	**2,115**	**1,836**	**1,878**	**2,290**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,666	2,657	2,398	2,333	3,210	3,834	4,481	3,663	3,554	2,473	2,504	2,987
Total Peak Load	**2,666**	**2,657**	**2,398**	**2,333**	**3,210**	**3,834**	**4,481**	**3,663**	**3,554**	**2,473**	**2,504**	**2,987**

Monthly Summary[1]	1/2031	2/2031	3/2031	4/2031	5/2031	6/2031	7/2031	8/2031	9/2031	10/2031	11/2031	12/2031
Average Load (aMW)–50th Percentile												
Residential	923	845	736	621	553	597	877	710	580	582	708	1,035
Commercial	561	534	510	499	500	535	620	559	552	532	523	591
Irrigation	2	2	5	97	329	584	719	593	339	84	5	3
Industrial	387	382	384	365	357	392	389	394	389	401	395	378
Additional Firm	126	123	118	116	107	103	111	110	108	112	118	124
Loss	170	160	148	143	158	192	240	207	169	143	147	184
System Load	**2,169**	**2,047**	**1,901**	**1,842**	**2,005**	**2,404**	**2,956**	**2,573**	**2,137**	**1,854**	**1,896**	**2,314**
Light Load	2,014	1,880	1,736	1,666	1,811	2,172	2,674	2,277	1,905	1,668	1,747	2,135
Heavy Load	2,281	2,172	2,030	1,970	2,144	2,590	3,159	2,807	2,307	1,988	2,016	2,443
Total Load	**2,169**	**2,047**	**1,901**	**1,842**	**2,005**	**2,404**	**2,956**	**2,573**	**2,137**	**1,854**	**1,896**	**2,314**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,685	2,672	2,414	2,349	3,244	3,877	4,540	3,703	3,594	2,493	2,521	3,009
Total Peak Load	**2,685**	**2,672**	**2,414**	**2,349**	**3,244**	**3,877**	**4,540**	**3,703**	**3,594**	**2,493**	**2,521**	**3,009**

Monthly Summary[1]	1/2032	2/2032	3/2032	4/2032	5/2032	6/2032	7/2032	8/2032	9/2032	10/2032	11/2032	12/2032
Average Load (aMW)–50th Percentile												
Residential	932	852	742	627	559	605	889	720	587	587	714	1,045
Commercial	566	538	514	503	505	540	626	564	558	537	528	597
Irrigation	2	2	5	97	330	586	721	595	340	84	6	3
Industrial	392	375	390	370	362	398	394	399	395	407	400	384
Additional Firm	125	118	117	116	106	103	110	110	108	111	117	123
Loss	172	160	149	144	160	194	242	209	170	145	148	186
System Load	**2,189**	**2,045**	**1,917**	**1,858**	**2,023**	**2,426**	**2,983**	**2,598**	**2,158**	**1,871**	**1,913**	**2,338**
Light Load	2,033	1,879	1,751	1,681	1,828	2,191	2,699	2,299	1,924	1,683	1,763	2,157
Heavy Load	2,302	2,181	2,037	1,987	2,177	2,598	3,189	2,833	2,329	2,019	2,024	2,468
Total Load	**2,189**	**2,045**	**1,917**	**1,858**	**2,023**	**2,426**	**2,983**	**2,598**	**2,158**	**1,871**	**1,913**	**2,338**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,706	2,687	2,430	2,365	3,277	3,918	4,599	3,741	3,633	2,513	2,538	3,032
Total Peak Load	**2,706**	**2,687**	**2,430**	**2,365**	**3,277**	**3,918**	**4,599**	**3,741**	**3,633**	**2,513**	**2,538**	**3,032**

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2033	2/2033	3/2033	4/2033	5/2033	6/2033	7/2033	8/2033	9/2033	10/2033	11/2033	12/2033
Average Load (aMW)–50th Percentile												
Residential	941	859	749	633	566	613	902	730	594	593	721	1,056
Commercial	572	543	518	508	510	546	632	570	564	543	533	604
Irrigation	2	2	5	97	332	589	724	598	342	85	6	3
Industrial	398	394	396	376	367	404	400	405	401	413	406	389
Additional Firm	125	123	117	116	106	103	110	110	108	111	117	123
Loss	174	163	150	146	161	196	245	211	172	146	150	187
System Load	**2,212**	**2,083**	**1,936**	**1,876**	**2,043**	**2,450**	**3,013**	**2,624**	**2,181**	**1,890**	**1,932**	**2,362**
Light Load	2,054	1,914	1,768	1,697	1,846	2,213	2,726	2,322	1,945	1,700	1,780	2,180
Heavy Load	2,336	2,210	2,057	2,006	2,198	2,623	3,240	2,842	2,354	2,039	2,044	2,494
Total Load	**2,212**	**2,083**	**1,936**	**1,876**	**2,043**	**2,450**	**3,013**	**2,624**	**2,181**	**1,890**	**1,932**	**2,362**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,728	2,704	2,448	2,383	3,312	3,963	4,659	3,782	3,674	2,534	2,557	3,055
Total Peak Load	**2,728**	**2,704**	**2,448**	**2,383**	**3,312**	**3,963**	**4,659**	**3,782**	**3,674**	**2,534**	**2,557**	**3,055**

Monthly Summary[1]	1/2034	2/2034	3/2034	4/2034	5/2034	6/2034	7/2034	8/2034	9/2034	10/2034	11/2034	12/2034
Average Load (aMW)–50th Percentile												
Residential	950	866	756	639	572	621	915	740	602	598	727	1,067
Commercial	577	547	523	513	515	552	638	576	571	548	538	610
Irrigation	2	2	5	98	333	591	727	600	343	85	6	3
Industrial	403	399	401	381	372	409	405	411	406	419	412	395
Additional Firm	124	122	117	115	106	102	110	110	107	110	116	122
Loss	176	164	152	147	163	198	247	213	174	147	151	189
System Load	**2,233**	**2,100**	**1,953**	**1,893**	**2,061**	**2,473**	**3,042**	**2,650**	**2,203**	**1,907**	**1,950**	**2,387**
Light Load	2,073	1,930	1,783	1,713	1,863	2,234	2,752	2,345	1,964	1,716	1,796	2,202
Heavy Load	2,359	2,229	2,075	2,037	2,205	2,648	3,271	2,870	2,377	2,058	2,062	2,532
Total Load	**2,233**	**2,100**	**1,953**	**1,893**	**2,061**	**2,473**	**3,042**	**2,650**	**2,203**	**1,907**	**1,950**	**2,387**
Peak Load (MW)–90th Percentile												
System Peak (1 hour)	2,749	2,720	2,464	2,399	3,345	4,005	4,719	3,822	3,714	2,553	2,575	3,077
Total Peak Load	**2,749**	**2,720**	**2,464**	**2,399**	**3,345**	**4,005**	**4,719**	**3,822**	**3,714**	**2,553**	**2,575**	**3,077**

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Annual Summary

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Billed Sales (MWh)–50th Percentile										
Residential	5,144,709	5,270,572	5,372,014	5,441,649	5,508,610	5,556,959	5,616,876	5,673,430	5,740,794	5,823,961
Commercial	4,076,100	4,144,898	4,182,636	4,212,195	4,247,398	4,285,793	4,327,161	4,369,098	4,410,017	4,452,065
Irrigation	1,863,039	1,902,156	1,915,919	1,918,336	1,913,727	1,924,815	1,937,547	1,941,972	1,944,197	1,953,855
Industrial	2,413,190	2,573,787	2,642,594	2,692,807	2,738,789	2,786,007	2,837,470	2,889,584	2,942,288	2,994,216
Additional Firm	880,500	901,900	905,900	909,500	909,600	920,600	922,700	957,500	986,600	1,006,800
System Sales	14,377,538	14,793,313	15,019,064	15,174,487	15,318,124	15,474,174	15,641,753	15,831,584	16,023,896	16,230,898
Total Sales	**14,377,538**	**14,793,313**	**15,019,064**	**15,174,487**	**15,318,124**	**15,474,174**	**15,641,753**	**15,831,584**	**16,023,896**	**16,230,898**
Generation Month Sales (MWh)–50th Percentile										
Residential	5,154,280	5,295,641	5,377,433	5,446,875	5,512,460	5,579,744	5,621,345	5,678,710	5,747,258	5,849,294
Commercial	4,079,899	4,158,522	4,184,382	4,214,240	4,249,614	4,299,933	4,329,571	4,371,459	4,412,441	4,466,707
Irrigation	1,863,058	1,902,215	1,915,920	1,918,334	1,913,732	1,924,874	1,937,549	1,941,973	1,944,202	1,953,915
Industrial	2,426,435	2,579,462	2,646,735	2,696,599	2,742,683	2,790,251	2,841,768	2,893,931	2,946,571	2,998,631
Additional Firm	880,500	901,900	905,900	909,500	909,600	920,600	922,700	957,500	986,600	1,006,800
System Sales	14,404,172	14,837,741	15,030,370	15,185,549	15,328,090	15,515,403	15,652,934	15,843,573	16,037,072	16,275,347
Total Sales	**14,404,172**	**14,837,741**	**15,030,370**	**15,185,549**	**15,328,090**	**15,515,403**	**15,652,934**	**15,843,573**	**16,037,072**	**16,275,347**
Loss	1,244,160	1,278,960	1,294,764	1,307,629	1,319,635	1,335,210	1,346,414	1,360,666	1,375,528	1,395,261
Required Generation	15,648,332	16,116,700	16,325,134	16,493,178	16,647,725	16,850,613	16,999,348	17,204,238	17,412,599	17,670,608
Average Load (aMW)–50th Percentile										
Residential	588	603	614	622	629	635	642	648	656	666
Commercial	466	473	478	481	485	490	494	499	504	509
Irrigation	213	217	219	219	218	219	221	222	222	222
Industrial	277	294	302	308	313	318	324	330	336	341
Additional Firm	101	103	103	104	104	105	105	109	113	115
Loss	142	146	148	149	151	152	154	155	157	159
System Load	1,786	1,835	1,864	1,883	1,900	1,918	1,941	1,964	1,988	2,012
Light Load	1,621	1,665	1,691	1,709	1,725	1,741	1,761	1,782	1,804	1,826
Heavy Load	1,916	1,968	2,000	2,020	2,038	2,057	2,081	2,106	2,133	2,157
Total Load	**1,786**	**1,835**	**1,864**	**1,883**	**1,900**	**1,918**	**1,941**	**1,964**	**1,988**	**2,012**
Peak Load (MW)–90th Percentile										
System Peak (1 Hour)	3,537	3,630	3,696	3,752	3,805	3,862	3,922	3,981	4,041	4,105
Total Peak Load	**3,537**	**3,630**	**3,696**	**3,752**	**3,805**	**3,862**	**3,922**	**3,981**	**4,041**	**4,105**

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Billed Sales (MWh)–50th Percentile										
Residential	5,908,438	5,993,931	6,078,974	6,166,782	6,253,879	6,328,432	6,396,305	6,464,673	6,535,425	6,605,069
Commercial	4,495,518	4,538,294	4,579,379	4,623,210	4,669,570	4,713,503	4,755,847	4,800,838	4,849,140	4,896,765
Irrigation	1,966,693	1,979,082	1,990,214	2,000,471	2,012,334	2,022,468	2,031,444	2,038,333	2,047,116	2,054,980
Industrial	3,047,748	3,101,332	3,154,544	3,207,964	3,263,009	3,314,431	3,364,294	3,412,358	3,461,829	3,509,388
Additional Firm	1,006,800	1,004,100	1,004,100	998,800	998,800	1,004,100	1,004,100	998,800	998,800	993,500
System Sales	16,425,196	16,616,739	16,807,211	16,997,227	17,197,592	17,382,934	17,551,990	17,715,002	17,892,310	18,059,702
Total Sales	**16,425,196**	**16,616,739**	**16,807,211**	**16,997,227**	**17,197,592**	**17,382,934**	**17,551,990**	**17,715,002**	**17,892,310**	**18,059,702**
Generation Month Sales (MWh)–50th Percentile										
Residential	5,915,091	6,000,558	6,085,816	6,193,260	6,259,745	6,333,805	6,401,722	6,490,712	6,540,950	6,610,536
Commercial	4,497,988	4,540,679	4,581,913	4,638,404	4,672,117	4,715,970	4,758,459	4,816,547	4,851,901	4,899,689
Irrigation	1,966,699	1,979,087	1,990,219	2,000,532	2,012,339	2,022,472	2,031,447	2,038,393	2,047,120	2,054,984
Industrial	3,052,167	3,105,721	3,158,950	3,212,504	3,267,250	3,318,543	3,368,258	3,416,438	3,465,751	3,513,496
Additional Firm	1,006,800	1,004,100	1,004,100	998,800	998,800	1,004,100	1,004,100	998,800	998,800	993,500
System Sales	16,438,745	16,630,145	16,820,998	17,043,500	17,210,252	17,394,891	17,563,986	17,760,890	17,904,522	18,072,204
Total Sales	**16,438,745**	**16,630,145**	**16,820,998**	**17,043,500**	**17,210,252**	**17,394,891**	**17,563,986**	**17,760,890**	**17,904,522**	**18,072,204**
Loss	1,409,006	1,425,605	1,441,996	1,461,742	1,475,765	1,491,301	1,505,731	1,523,214	1,535,214	1,549,909
Required Generation	17,847,751	18,055,750	18,262,994	18,505,242	18,686,016	18,886,192	19,069,716	19,284,105	19,439,736	19,622,113
Average Load (aMW)–50th Percentile										
Residential	675	685	695	705	715	723	731	739	747	755
Commercial	513	518	523	528	533	538	543	548	554	559
Irrigation	225	226	227	228	230	231	232	232	234	235
Industrial	348	355	361	366	373	379	385	389	396	401
Additional Firm	115	115	115	114	114	115	115	114	114	113
Loss	161	163	165	166	168	170	172	173	175	177
System Load	2,037	2,061	2,085	2,107	2,133	2,156	2,177	2,195	2,219	2,240
Light Load	1,849	1,871	1,892	1,912	1,936	1,957	1,976	1,992	2,014	2,033
Heavy Load	2,185	2,210	2,236	2,260	2,288	2,312	2,328	2,347	2,373	2,396
Total Load	**2,037**	**2,061**	**2,085**	**2,107**	**2,133**	**2,156**	**2,177**	**2,195**	**2,219**	**2,240**
Peak Load (MW)–90th Percentile										
System Peak (1 Hour)	4,168	4,231	4,293	4,355	4,419	4,481	4,540	4,599	4,659	4,719
Total Peak Load	4,168	4,231	4,293	4,355	4,419	4,481	4,540	4,599	4,659	4,719

70th Percentile Load Forecast

Monthly Summary[1]	1/2015	2/2015	3/2015	4/2015	5/2015	6/2015	7/2015	8/2015	9/2015	10/2015	11/2015	12/2015
Average Load (aMW)–70th Percentile												
Residential	781	730	622	519	460	491	698	565	472	492	606	863
Commercial	492	479	450	440	437	462	541	481	467	457	452	507
Irrigation	2	2	6	106	348	577	678	555	324	84	5	3
Industrial	277	274	276	262	256	281	279	282	279	288	283	285
Additional Firm	105	103	99	101	95	100	98	98	101	100	104	103
Loss	143	137	124	122	138	168	205	174	142	120	123	153
System Load	**1,800**	**1,724**	**1,575**	**1,549**	**1,734**	**2,079**	**2,498**	**2,156**	**1,785**	**1,541**	**1,573**	**1,914**
Light Load	1,672	1,584	1,438	1,402	1,567	1,878	2,260	1,908	1,591	1,387	1,449	1,766
Heavy Load	1,902	1,829	1,683	1,657	1,878	2,226	2,686	2,351	1,940	1,653	1,682	2,030
Total Load	**1,800**	**1,724**	**1,575**	**1,549**	**1,734**	**2,079**	**2,498**	**2,156**	**1,785**	**1,541**	**1,573**	**1,914**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,330	2,400	2,128	2,027	2,682	3,163	3,576	3,029	2,901	2,133	2,233	2,625
Total Peak Load	**2,330**	**2,400**	**2,128**	**2,027**	**2,682**	**3,163**	**3,576**	**3,029**	**2,901**	**2,133**	**2,233**	**2,625**

Monthly Summary[1]	1/2016	2/2016	3/2016	4/2016	5/2016	6/2016	7/2016	8/2016	9/2016	10/2016	11/2016	12/2016
Average Load (aMW)–70th Percentile												
Residential	799	745	636	531	472	505	718	581	484	504	619	881
Commercial	500	486	457	447	444	470	550	489	475	465	459	514
Irrigation	2	2	6	108	355	588	692	567	331	85	6	3
Industrial	296	283	294	279	273	300	297	301	298	307	302	293
Additional Firm	110	105	105	104	97	94	101	101	99	101	105	109
Loss	147	139	127	125	142	172	210	179	145	123	126	156
System Load	**1,854**	**1,761**	**1,624**	**1,594**	**1,782**	**2,128**	**2,568**	**2,218**	**1,833**	**1,585**	**1,617**	**1,954**
Light Load	1,722	1,618	1,483	1,443	1,611	1,922	2,324	1,963	1,634	1,426	1,489	1,803
Heavy Load	1,968	1,867	1,726	1,705	1,930	2,279	2,779	2,403	1,992	1,711	1,719	2,073
Total Load	**1,854**	**1,761**	**1,624**	**1,594**	**1,782**	**2,128**	**2,568**	**2,218**	**1,833**	**1,585**	**1,617**	**1,954**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,400	2,437	2,181	2,082	2,748	3,266	3,669	3,122	2,992	2,183	2,281	2,663
Total Peak Load	**2,400**	**2,437**	**2,181**	**2,082**	**2,748**	**3,266**	**3,669**	**3,122**	**2,992**	**2,183**	**2,281**	**2,663**

Monthly Summary[1]	1/2017	2/2017	3/2017	4/2017	5/2017	6/2017	7/2017	8/2017	9/2017	10/2017	11/2017	12/2017
Average Load (aMW)–70th Percentile												
Residential	814	758	647	540	481	516	734	594	494	512	630	894
Commercial	505	490	460	451	448	475	555	494	480	469	464	518
Irrigation	2	2	6	109	357	592	697	571	333	86	6	3
Industrial	304	300	302	287	280	308	305	309	306	315	310	299
Additional Firm	111	110	106	105	97	94	102	102	100	101	105	109
Loss	149	142	129	127	144	174	213	182	148	125	128	158
System Load	**1,884**	**1,802**	**1,649**	**1,618**	**1,808**	**2,159**	**2,606**	**2,251**	**1,861**	**1,609**	**1,642**	**1,980**
Light Load	1,750	1,656	1,506	1,464	1,634	1,950	2,358	1,992	1,659	1,448	1,513	1,827
Heavy Load	2,000	1,912	1,752	1,741	1,946	2,312	2,820	2,439	2,022	1,737	1,746	2,111
Total Load	**1,884**	**1,802**	**1,649**	**1,618**	**1,808**	**2,159**	**2,606**	**2,251**	**1,861**	**1,609**	**1,642**	**1,980**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,426	2,472	2,204	2,103	2,788	3,320	3,736	3,172	3,042	2,209	2,305	2,686
Total Peak Load	**2,426**	**2,472**	**2,204**	**2,103**	**2,788**	**3,320**	**3,736**	**3,172**	**3,042**	**2,209**	**2,305**	**2,686**

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2018	2/2018	3/2018	4/2018	5/2018	6/2018	7/2018	8/2018	9/2018	10/2018	11/2018	12/2018
Average Load (aMW)–70th Percentile												
Residential	823	766	654	547	488	524	747	604	501	518	636	905
Commercial	508	492	463	454	452	478	559	498	485	473	467	523
Irrigation	2	2	6	109	357	593	698	571	334	86	6	3
Industrial	309	306	308	292	286	314	311	315	312	321	316	304
Additional Firm	112	110	106	105	98	94	102	102	100	102	106	110
Loss	151	144	130	128	145	176	215	183	149	126	129	160
System Load	**1,906**	**1,821**	**1,667**	**1,635**	**1,826**	**2,180**	**2,631**	**2,274**	**1,880**	**1,626**	**1,660**	**2,003**
Light Load	1,770	1,673	1,522	1,479	1,650	1,969	2,381	2,012	1,676	1,463	1,529	1,848
Heavy Load	2,013	1,931	1,771	1,759	1,965	2,334	2,847	2,463	2,059	1,744	1,765	2,136
Total Load	**1,906**	**1,821**	**1,667**	**1,635**	**1,826**	**2,180**	**2,631**	**2,274**	**1,880**	**1,626**	**1,660**	**2,003**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,433	2,483	2,213	2,109	2,820	3,356	3,793	3,205	3,076	2,228	2,313	2,703
Total Peak Load	**2,433**	**2,483**	**2,213**	**2,109**	**2,820**	**3,356**	**3,793**	**3,205**	**3,076**	**2,228**	**2,313**	**2,703**

Monthly Summary[1]	1/2019	2/2019	3/2019	4/2019	5/2019	6/2019	7/2019	8/2019	9/2019	10/2019	11/2019	12/2019
Average Load (aMW)–70th Percentile												
Residential	833	774	661	553	495	533	759	614	508	523	643	913
Commercial	512	496	466	457	455	483	564	503	490	477	471	528
Irrigation	2	2	6	109	356	592	696	570	333	86	6	3
Industrial	315	311	313	297	291	319	316	320	317	327	321	309
Additional Firm	112	110	106	105	98	94	102	102	100	102	106	110
Loss	152	145	132	129	147	177	217	185	151	128	131	161
System Load	**1,926**	**1,838**	**1,683**	**1,650**	**1,842**	**2,198**	**2,654**	**2,294**	**1,898**	**1,642**	**1,677**	**2,024**
Light Load	1,789	1,689	1,537	1,493	1,664	1,985	2,401	2,030	1,692	1,478	1,545	1,867
Heavy Load	2,035	1,950	1,798	1,765	1,982	2,368	2,853	2,484	2,078	1,761	1,783	2,158
Total Load	**1,926**	**1,838**	**1,683**	**1,650**	**1,842**	**2,198**	**2,654**	**2,294**	**1,898**	**1,642**	**1,677**	**2,024**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,456	2,500	2,231	2,127	2,849	3,387	3,847	3,234	3,108	2,246	2,332	2,723
Total Peak Load	**2,456**	**2,500**	**2,231**	**2,127**	**2,849**	**3,387**	**3,847**	**3,234**	**3,108**	**2,246**	**2,332**	**2,723**

Monthly Summary[1]	1/2020	2/2020	3/2020	4/2020	5/2020	6/2020	7/2020	8/2020	9/2020	10/2020	11/2020	12/2020
Average Load (aMW)–70th Percentile												
Residential	839	779	665	557	500	539	769	621	513	527	647	922
Commercial	517	500	470	461	460	487	569	507	495	482	475	533
Irrigation	2	2	6	109	358	595	700	573	335	86	6	3
Industrial	320	306	318	302	296	325	322	326	322	332	327	315
Additional Firm	113	108	107	107	99	96	103	103	101	103	107	111
Loss	154	145	133	130	148	179	219	187	152	129	132	163
System Load	**1,946**	**1,839**	**1,700**	**1,667**	**1,860**	**2,221**	**2,681**	**2,318**	**1,919**	**1,659**	**1,693**	**2,047**
Light Load	1,807	1,690	1,552	1,508	1,681	2,006	2,425	2,051	1,710	1,493	1,560	1,889
Heavy Load	2,055	1,950	1,816	1,782	2,015	2,378	2,882	2,528	2,085	1,779	1,811	2,171
Total Load	**1,946**	**1,839**	**1,700**	**1,667**	**1,860**	**2,221**	**2,681**	**2,318**	**1,919**	**1,659**	**1,693**	**2,047**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,479	2,515	2,249	2,145	2,882	3,426	3,905	3,270	3,143	2,264	2,351	2,747
Total Peak Load	**2,479**	**2,515**	**2,249**	**2,145**	**2,882**	**3,426**	**3,905**	**3,270**	**3,143**	**2,264**	**2,351**	**2,747**

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2021	2/2021	3/2021	4/2021	5/2021	6/2021	7/2021	8/2021	9/2021	10/2021	11/2021	12/2021
Average Load (aMW)–70th Percentile												
Residential	847	785	671	562	506	547	780	630	520	532	653	931
Commercial	522	504	474	465	464	493	574	513	501	486	480	539
Irrigation	2	2	6	110	360	599	704	577	337	87	6	3
Industrial	326	323	324	308	301	331	328	332	328	338	333	320
Additional Firm	113	112	108	107	99	96	103	103	101	103	107	112
Loss	155	147	134	132	150	181	221	189	154	130	133	165
System Load	**1,967**	**1,873**	**1,717**	**1,684**	**1,880**	**2,245**	**2,710**	**2,344**	**1,940**	**1,677**	**1,711**	**2,070**
Light Load	1,826	1,721	1,568	1,524	1,699	2,028	2,452	2,074	1,730	1,509	1,577	1,910
Heavy Load	2,088	1,987	1,824	1,801	2,036	2,404	2,914	2,557	2,109	1,810	1,819	2,195
Total Load	**1,967**	**1,873**	**1,717**	**1,684**	**1,880**	**2,245**	**2,710**	**2,344**	**1,940**	**1,677**	**1,711**	**2,070**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,495	2,531	2,263	2,158	2,916	3,469	3,965	3,310	3,182	2,284	2,365	2,766
Total Peak Load	**2,495**	**2,531**	**2,263**	**2,158**	**2,916**	**3,469**	**3,965**	**3,310**	**3,182**	**2,284**	**2,365**	**2,766**

Monthly Summary[1]	1/2022	2/2022	3/2022	4/2022	5/2022	6/2022	7/2022	8/2022	9/2022	10/2022	11/2022	12/2022
Average Load (aMW)–70th Percentile												
Residential	855	791	677	567	512	554	791	639	526	536	658	941
Commercial	527	508	478	469	469	498	580	518	506	491	484	544
Irrigation	2	2	6	110	361	600	706	578	338	87	6	3
Industrial	332	329	330	314	307	337	334	338	334	345	339	326
Additional Firm	119	117	112	111	102	99	106	106	104	107	112	117
Loss	157	149	135	133	151	182	223	191	155	132	135	167
System Load	**1,992**	**1,895**	**1,738**	**1,704**	**1,902**	**2,270**	**2,740**	**2,371**	**1,964**	**1,698**	**1,733**	**2,098**
Light Load	1,850	1,741	1,587	1,542	1,718	2,050	2,479	2,098	1,751	1,527	1,597	1,936
Heavy Load	2,115	2,011	1,847	1,823	2,060	2,430	2,964	2,567	2,134	1,832	1,843	2,226
Total Load	**1,992**	**1,895**	**1,738**	**1,704**	**1,902**	**2,270**	**2,740**	**2,371**	**1,964**	**1,698**	**1,733**	**2,098**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,513	2,550	2,281	2,173	2,952	3,510	4,026	3,348	3,221	2,307	2,383	2,792
Total Peak Load	**2,513**	**2,550**	**2,281**	**2,173**	**2,952**	**3,510**	**4,026**	**3,348**	**3,221**	**2,307**	**2,383**	**2,792**

Monthly Summary[1]	1/2023	2/2023	3/2023	4/2023	5/2023	6/2023	7/2023	8/2023	9/2023	10/2023	11/2023	12/2023
Average Load (aMW)–70th Percentile												
Residential	864	798	684	574	518	562	803	649	533	542	664	954
Commercial	532	512	482	473	473	503	585	523	512	496	489	550
Irrigation	2	2	6	110	361	600	707	579	338	87	6	3
Industrial	338	335	336	319	312	343	340	344	340	351	345	332
Additional Firm	123	121	116	114	105	102	109	109	107	110	115	121
Loss	159	151	137	134	153	184	226	193	157	133	136	169
System Load	**2,019**	**1,918**	**1,760**	**1,725**	**1,923**	**2,294**	**2,769**	**2,397**	**1,987**	**1,719**	**1,755**	**2,128**
Light Load	1,874	1,762	1,607	1,561	1,738	2,072	2,505	2,121	1,772	1,546	1,617	1,964
Heavy Load	2,143	2,035	1,870	1,857	2,070	2,457	2,996	2,596	2,159	1,855	1,866	2,270
Total Load	**2,019**	**1,918**	**1,760**	**1,725**	**1,923**	**2,294**	**2,769**	**2,397**	**1,987**	**1,719**	**1,755**	**2,128**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,541	2,572	2,303	2,194	2,987	3,552	4,086	3,387	3,261	2,330	2,406	2,822
Total Peak Load	**2,541**	**2,572**	**2,303**	**2,194**	**2,987**	**3,552**	**4,086**	**3,387**	**3,261**	**2,330**	**2,406**	**2,822**

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2024	2/2024	3/2024	4/2024	5/2024	6/2024	7/2024	8/2024	9/2024	10/2024	11/2024	12/2024
Average Load (aMW)–70th Percentile												
Residential	876	808	692	581	527	572	817	661	541	548	672	967
Commercial	537	516	486	477	478	508	590	528	518	501	494	556
Irrigation	2	2	6	111	363	603	710	582	340	88	6	3
Industrial	344	329	342	325	318	349	346	350	346	357	351	338
Additional Firm	126	119	118	117	107	104	111	111	109	112	118	124
Loss	161	151	139	136	154	186	228	195	159	135	138	171
System Load	**2,046**	**1,925**	**1,783**	**1,747**	**1,947**	**2,322**	**2,803**	**2,427**	**2,013**	**1,741**	**1,778**	**2,159**
Light Load	1,900	1,769	1,628	1,581	1,759	2,097	2,536	2,148	1,794	1,566	1,638	1,992
Heavy Load	2,161	2,041	1,904	1,869	2,095	2,502	3,014	2,629	2,204	1,867	1,891	2,302
Total Load	**2,046**	**1,925**	**1,783**	**1,747**	**1,947**	**2,322**	**2,803**	**2,427**	**2,013**	**1,741**	**1,778**	**2,159**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,573	2,596	2,328	2,218	3,025	3,600	4,151	3,431	3,305	2,354	2,433	2,853
Total Peak Load	**2,573**	**2,596**	**2,328**	**2,218**	**3,025**	**3,600**	**4,151**	**3,431**	**3,305**	**2,354**	**2,433**	**2,853**

Monthly Summary[1]	1/2025	2/2025	3/2025	4/2025	5/2025	6/2025	7/2025	8/2025	9/2025	10/2025	11/2025	12/2025
Average Load (aMW)–70th Percentile												
Residential	887	817	701	589	535	582	832	672	550	555	680	981
Commercial	542	520	490	482	483	513	596	534	524	506	499	561
Irrigation	2	2	6	111	365	607	715	586	342	88	6	3
Industrial	350	347	348	331	323	355	352	357	353	364	358	344
Additional Firm	126	124	118	117	107	104	111	111	109	112	118	124
Loss	163	154	140	138	156	189	231	198	161	136	140	173
System Load	**2,071**	**1,964**	**1,803**	**1,767**	**1,969**	**2,349**	**2,837**	**2,457**	**2,037**	**1,761**	**1,799**	**2,186**
Light Load	1,923	1,804	1,647	1,599	1,779	2,122	2,567	2,174	1,817	1,585	1,658	2,017
Heavy Load	2,188	2,084	1,926	1,890	2,119	2,531	3,050	2,679	2,214	1,889	1,924	2,319
Total Load	**2,071**	**1,964**	**1,803**	**1,767**	**1,969**	**2,349**	**2,837**	**2,457**	**2,037**	**1,761**	**1,799**	**2,186**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,601	2,617	2,350	2,240	3,062	3,648	4,215	3,476	3,349	2,377	2,456	2,880
Total Peak Load	**2,601**	**2,617**	**2,350**	**2,240**	**3,062**	**3,648**	**4,215**	**3,476**	**3,349**	**2,377**	**2,456**	**2,880**

Monthly Summary[1]	1/2026	2/2026	3/2026	4/2026	5/2026	6/2026	7/2026	8/2026	9/2026	10/2026	11/2026	12/2026
Average Load (aMW)–70th Percentile												
Residential	899	827	709	597	543	592	847	684	558	562	688	994
Commercial	547	524	494	486	487	518	602	539	530	511	503	567
Irrigation	2	2	6	112	367	610	719	589	344	89	6	3
Industrial	356	353	354	337	329	362	358	363	359	370	364	350
Additional Firm	126	123	118	116	107	103	111	110	108	112	118	124
Loss	165	156	142	139	158	191	234	200	163	138	141	176
System Load	**2,095**	**1,985**	**1,823**	**1,787**	**1,991**	**2,376**	**2,871**	**2,486**	**2,062**	**1,781**	**1,820**	**2,213**
Light Load	1,946	1,824	1,665	1,617	1,799	2,146	2,597	2,200	1,838	1,603	1,677	2,042
Heavy Load	2,214	2,106	1,948	1,911	2,157	2,544	3,086	2,712	2,241	1,911	1,946	2,348
Total Load	**2,095**	**1,985**	**1,823**	**1,787**	**1,991**	**2,376**	**2,871**	**2,486**	**2,062**	**1,781**	**1,820**	**2,213**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,627	2,637	2,370	2,261	3,099	3,697	4,278	3,521	3,393	2,399	2,479	2,906
Total Peak Load	**2,627**	**2,637**	**2,370**	**2,261**	**3,099**	**3,697**	**4,278**	**3,521**	**3,393**	**2,399**	**2,479**	**2,906**

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2027	2/2027	3/2027	4/2027	5/2027	6/2027	7/2027	8/2027	9/2027	10/2027	11/2027	12/2027
Average Load (aMW)–70th Percentile												
Residential	910	836	718	604	551	602	862	697	567	569	696	1,008
Commercial	552	528	498	490	492	524	607	544	535	516	508	573
Irrigation	2	2	6	112	369	614	723	592	346	89	6	3
Industrial	363	359	360	342	335	368	364	369	365	376	370	356
Additional Firm	126	123	118	116	107	103	111	110	108	112	118	124
Loss	167	157	143	141	160	193	236	202	165	139	143	178
System Load	**2,120**	**2,006**	**1,843**	**1,806**	**2,013**	**2,403**	**2,904**	**2,515**	**2,086**	**1,801**	**1,840**	**2,241**
Light Load	1,969	1,843	1,683	1,635	1,819	2,170	2,627	2,226	1,860	1,621	1,696	2,068
Heavy Load	2,250	2,129	1,959	1,932	2,180	2,573	3,122	2,743	2,267	1,944	1,957	2,377
Total Load	**2,120**	**2,006**	**1,843**	**1,806**	**2,013**	**2,403**	**2,904**	**2,515**	**2,086**	**1,801**	**1,840**	**2,241**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,653	2,656	2,391	2,281	3,136	3,744	4,341	3,565	3,437	2,422	2,500	2,932
Total Peak Load	**2,653**	**2,656**	**2,391**	**2,281**	**3,136**	**3,744**	**4,341**	**3,565**	**3,437**	**2,422**	**2,500**	**2,932**

Monthly Summary[1]	1/2028	2/2028	3/2028	4/2028	5/2028	6/2028	7/2028	8/2028	9/2028	10/2028	11/2028	12/2028
Average Load (aMW)–70th Percentile												
Residential	922	846	727	612	560	612	877	709	576	576	705	1,022
Commercial	558	532	502	494	497	529	613	550	541	521	513	579
Irrigation	2	2	6	113	371	617	727	595	347	89	6	3
Industrial	369	352	367	348	340	374	371	375	371	383	376	362
Additional Firm	125	118	117	116	106	103	110	110	108	111	117	123
Loss	169	158	145	142	161	195	239	205	167	141	144	180
System Load	**2,145**	**2,010**	**1,864**	**1,826**	**2,035**	**2,429**	**2,937**	**2,544**	**2,111**	**1,822**	**1,861**	**2,268**
Light Load	1,991	1,846	1,702	1,652	1,839	2,194	2,657	2,251	1,882	1,639	1,714	2,093
Heavy Load	2,276	2,130	1,980	1,965	2,190	2,601	3,177	2,755	2,294	1,966	1,979	2,419
Total Load	**2,145**	**2,010**	**1,864**	**1,826**	**2,035**	**2,429**	**2,937**	**2,544**	**2,111**	**1,822**	**1,861**	**2,268**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,680	2,675	2,412	2,303	3,172	3,792	4,404	3,609	3,481	2,444	2,523	2,960
Total Peak Load	**2,680**	**2,675**	**2,412**	**2,303**	**3,172**	**3,792**	**4,404**	**3,609**	**3,481**	**2,444**	**2,523**	**2,960**

Monthly Summary[1]	1/2029	2/2029	3/2029	4/2029	5/2029	6/2029	7/2029	8/2029	9/2029	10/2029	11/2029	12/2029
Average Load (aMW)–70th Percentile												
Residential	934	856	736	620	568	622	893	721	585	583	713	1,034
Commercial	563	537	506	499	502	535	619	556	548	526	518	585
Irrigation	2	2	6	113	372	620	731	599	349	90	6	3
Industrial	375	371	373	354	346	381	377	382	378	389	383	367
Additional Firm	125	123	117	116	106	103	110	110	108	111	117	123
Loss	171	161	147	144	163	197	242	207	169	143	146	182
System Load	**2,170**	**2,050**	**1,885**	**1,847**	**2,058**	**2,457**	**2,972**	**2,575**	**2,136**	**1,843**	**1,883**	**2,294**
Light Load	2,015	1,883	1,721	1,671	1,860	2,220	2,688	2,279	1,905	1,658	1,734	2,117
Heavy Load	2,293	2,174	2,002	1,987	2,215	2,631	3,215	2,789	2,339	1,976	2,002	2,447
Total Load	**2,170**	**2,050**	**1,885**	**1,847**	**2,058**	**2,457**	**2,972**	**2,575**	**2,136**	**1,843**	**1,883**	**2,294**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,708	2,697	2,434	2,325	3,210	3,842	4,469	3,655	3,527	2,468	2,546	2,985
Total Peak Load	**2,708**	**2,697**	**2,434**	**2,325**	**3,210**	**3,842**	**4,469**	**3,655**	**3,527**	**2,468**	**2,546**	**2,985**

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2030	2/2030	3/2030	4/2030	5/2030	6/2030	7/2030	8/2030	9/2030	10/2030	11/2030	12/2030
Average Load (aMW)–70th Percentile												
Residential	944	864	743	627	575	631	907	732	593	589	720	1,045
Commercial	568	541	511	503	507	540	625	561	554	532	523	591
Irrigation	2	2	6	114	374	623	734	602	351	90	6	3
Industrial	381	377	379	360	352	387	383	388	384	395	389	373
Additional Firm	126	123	118	116	107	103	111	110	108	112	118	124
Loss	173	162	148	145	165	199	245	209	171	144	148	184
System Load	**2,194**	**2,070**	**1,904**	**1,866**	**2,080**	**2,483**	**3,004**	**2,603**	**2,160**	**1,862**	**1,902**	**2,320**
Light Load	2,037	1,902	1,739	1,688	1,879	2,243	2,717	2,304	1,926	1,675	1,753	2,141
Heavy Load	2,318	2,196	2,034	1,995	2,238	2,676	3,229	2,819	2,365	1,997	2,023	2,474
Total Load	**2,194**	**2,070**	**1,904**	**1,866**	**2,080**	**2,483**	**3,004**	**2,603**	**2,160**	**1,862**	**1,902**	**2,320**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,732	2,715	2,453	2,344	3,246	3,888	4,531	3,698	3,569	2,489	2,567	3,009
Total Peak Load	**2,732**	**2,715**	**2,453**	**2,344**	**3,246**	**3,888**	**4,531**	**3,698**	**3,569**	**2,489**	**2,567**	**3,009**

Monthly Summary[1]	1/2031	2/2031	3/2031	4/2031	5/2031	6/2031	7/2031	8/2031	9/2031	10/2031	11/2031	12/2031
Average Load (aMW)–70th Percentile												
Residential	953	871	750	633	582	640	919	743	600	594	726	1,056
Commercial	573	545	514	508	511	545	630	567	560	537	528	597
Irrigation	2	2	6	114	376	626	738	604	353	91	6	3
Industrial	387	382	384	365	357	392	389	394	389	401	395	378
Additional Firm	126	123	118	116	107	103	111	110	108	112	118	124
Loss	175	164	149	147	166	201	247	211	173	145	149	186
System Load	**2,216**	**2,088**	**1,922**	**1,883**	**2,099**	**2,507**	**3,033**	**2,629**	**2,182**	**1,880**	**1,920**	**2,344**
Light Load	2,057	1,918	1,755	1,704	1,897	2,265	2,744	2,327	1,945	1,691	1,769	2,163
Heavy Load	2,330	2,215	2,053	2,014	2,246	2,702	3,242	2,868	2,355	2,016	2,042	2,474
Total Load	**2,216**	**2,088**	**1,922**	**1,883**	**2,099**	**2,507**	**3,033**	**2,629**	**2,182**	**1,880**	**1,920**	**2,344**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,751	2,730	2,469	2,359	3,280	3,931	4,592	3,737	3,608	2,509	2,584	3,031
Total Peak Load	**2,751**	**2,730**	**2,469**	**2,359**	**3,280**	**3,931**	**4,592**	**3,737**	**3,608**	**2,509**	**2,584**	**3,031**

Monthly Summary[1]	1/2032	2/2032	3/2032	4/2032	5/2032	6/2032	7/2032	8/2032	9/2032	10/2032	11/2032	12/2032
Average Load (aMW)–70th Percentile												
Residential	962	878	756	639	589	648	932	753	607	600	732	1,067
Commercial	579	549	519	512	516	551	636	572	566	542	533	603
Irrigation	2	2	6	115	377	627	740	606	354	91	6	3
Industrial	392	375	390	370	362	398	394	399	395	407	400	384
Additional Firm	125	118	117	116	106	103	110	110	108	111	117	123
Loss	176	164	151	148	168	203	249	214	174	147	150	188
System Load	**2,236**	**2,087**	**1,939**	**1,900**	**2,118**	**2,530**	**3,062**	**2,654**	**2,203**	**1,897**	**1,938**	**2,367**
Light Load	2,076	1,917	1,770	1,719	1,914	2,286	2,770	2,349	1,965	1,707	1,785	2,185
Heavy Load	2,352	2,224	2,060	2,032	2,280	2,709	3,273	2,895	2,378	2,047	2,050	2,499
Total Load	**2,236**	**2,087**	**1,939**	**1,900**	**2,118**	**2,530**	**3,062**	**2,654**	**2,203**	**1,897**	**1,938**	**2,367**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,772	2,745	2,486	2,375	3,313	3,972	4,651	3,776	3,647	2,529	2,601	3,054
Total Peak Load	**2,772**	**2,745**	**2,486**	**2,375**	**3,313**	**3,972**	**4,651**	**3,776**	**3,647**	**2,529**	**2,601**	**3,054**

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2033	2/2033	3/2033	4/2033	5/2033	6/2033	7/2033	8/2033	9/2033	10/2033	11/2033	12/2033
Average Load (aMW)–70th Percentile												
Residential	971	885	763	645	596	657	946	764	614	605	738	1,078
Commercial	584	554	523	517	522	557	642	578	572	547	538	609
Irrigation	2	2	6	115	378	630	743	609	355	91	6	3
Industrial	398	394	396	376	367	404	400	405	401	413	406	389
Additional Firm	125	123	117	116	106	103	110	110	108	111	117	123
Loss	178	167	152	149	170	205	252	216	176	148	152	190
System Load	**2,259**	**2,124**	**1,957**	**1,918**	**2,139**	**2,556**	**3,093**	**2,682**	**2,227**	**1,916**	**1,957**	**2,392**
Light Load	2,097	1,952	1,787	1,735	1,933	2,308	2,798	2,373	1,985	1,724	1,803	2,208
Heavy Load	2,386	2,254	2,079	2,051	2,302	2,736	3,325	2,905	2,403	2,068	2,070	2,525
Total Load	**2,259**	**2,124**	**1,957**	**1,918**	**2,139**	**2,556**	**3,093**	**2,682**	**2,227**	**1,916**	**1,957**	**2,392**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,794	2,763	2,504	2,393	3,348	4,017	4,713	3,817	3,688	2,549	2,620	3,077
Total Peak Load	**2,794**	**2,763**	**2,504**	**2,393**	**3,348**	**4,017**	**4,713**	**3,817**	**3,688**	**2,549**	**2,620**	**3,077**

Monthly Summary[1]	1/2034	2/2034	3/2034	4/2034	5/2034	6/2034	7/2034	8/2034	9/2034	10/2034	11/2034	12/2034
Average Load (aMW)–70th Percentile												
Residential	980	892	769	651	603	666	959	774	622	610	744	1,089
Commercial	590	559	528	521	527	563	648	584	579	553	543	616
Irrigation	2	2	6	115	379	632	746	611	356	92	6	3
Industrial	403	399	401	381	372	409	405	411	406	419	412	395
Additional Firm	124	122	117	115	106	102	110	110	107	110	116	122
Loss	180	168	153	151	171	207	254	218	178	150	153	192
System Load	**2,280**	**2,142**	**1,974**	**1,935**	**2,159**	**2,579**	**3,123**	**2,708**	**2,249**	**1,934**	**1,974**	**2,416**
Light Load	2,117	1,968	1,803	1,751	1,950	2,330	2,825	2,396	2,005	1,740	1,819	2,230
Heavy Load	2,409	2,273	2,098	2,082	2,309	2,762	3,357	2,933	2,427	2,087	2,088	2,563
Total Load	**2,280**	**2,142**	**1,974**	**1,935**	**2,159**	**2,579**	**3,123**	**2,708**	**2,249**	**1,934**	**1,974**	**2,416**
Peak Load (MW)–95th Percentile												
System Peak (1 hour)	2,815	2,778	2,520	2,409	3,382	4,060	4,773	3,857	3,728	2,569	2,638	3,100
Total Peak Load	**2,815**	**2,778**	**2,520**	**2,409**	**3,382**	**4,060**	**4,773**	**3,857**	**3,728**	**2,569**	**2,638**	**3,100**

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Annual Summary

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Billed Sales (MWh)–70th Percentile										
Residential	5,317,055	5,447,177	5,552,704	5,625,914	5,695,969	5,747,179	5,809,857	5,869,137	5,939,209	6,025,044
Commercial	4,131,001	4,201,012	4,239,992	4,270,776	4,307,093	4,346,536	4,388,927	4,431,884	4,473,825	4,516,895
Irrigation	1,977,605	2,016,722	2,030,485	2,032,902	2,028,293	2,039,381	2,052,113	2,056,538	2,058,763	2,068,421
Industrial	2,413,190	2,573,787	2,642,594	2,692,807	2,738,789	2,786,007	2,837,470	2,889,584	2,942,288	2,994,216
Additional Firm	880,500	901,900	905,900	909,500	909,600	920,600	922,700	957,500	986,600	1,006,800
System Sales	14,719,352	15,140,599	15,371,675	15,531,900	15,679,743	15,839,703	16,011,067	16,204,643	16,400,686	16,611,376
Total Sales	**14,719,352**	**15,140,599**	**15,371,675**	**15,531,900**	**15,679,743**	**15,839,703**	**16,011,067**	**16,204,643**	**16,400,686**	**16,611,376**
Generation Month Sales (MWh)–70th Percentile										
Residential	5,326,729	5,472,945	5,558,208	5,631,202	5,699,862	5,770,615	5,814,359	5,874,448	5,945,701	6,051,025
Commercial	4,134,835	4,214,880	4,241,773	4,272,855	4,309,340	4,360,932	4,391,367	4,434,274	4,476,279	4,531,807
Irrigation	1,977,624	2,016,781	2,030,486	2,032,900	2,028,299	2,039,440	2,052,115	2,056,539	2,058,768	2,068,481
Industrial	2,426,435	2,579,462	2,646,735	2,696,599	2,742,683	2,790,251	2,841,768	2,893,931	2,946,571	2,998,631
Additional Firm	880,500	901,900	905,900	909,500	909,600	920,600	922,700	957,500	986,600	1,006,800
System Sales	14,746,123	15,185,968	15,383,103	15,543,056	15,689,784	15,881,839	16,022,310	16,216,691	16,413,918	16,656,744
Total Sales	**14,746,123**	**15,185,968**	**15,383,103**	**15,543,056**	**15,689,784**	**15,881,839**	**16,022,310**	**16,216,691**	**16,413,918**	**16,656,744**
Loss	1,276,987	1,312,390	1,328,626	1,341,950	1,354,358	1,370,388	1,381,874	1,396,485	1,411,705	1,431,876
Required Generation	16,023,110	16,498,358	16,711,729	16,885,006	17,044,142	17,252,227	17,404,184	17,613,176	17,825,623	18,088,620
Average Load (aMW)–70th Percentile										
Residential	608	623	634	643	651	657	664	671	679	689
Commercial	472	480	484	488	492	496	501	506	511	516
Irrigation	226	230	232	232	232	232	234	235	235	235
Industrial	277	294	302	308	313	318	324	330	336	341
Additional Firm	101	103	103	104	104	105	105	109	113	115
Loss	146	149	152	153	155	156	158	159	161	163
System Load	1,829	1,878	1,908	1,928	1,946	1,964	1,987	2,011	2,035	2,059
Light Load	1,660	1,705	1,731	1,749	1,766	1,782	1,803	1,825	1,847	1,869
Heavy Load	1,962	2,014	2,047	2,068	2,087	2,106	2,131	2,157	2,183	2,208
Total Load	**1,829**	**1,878**	**1,908**	**1,928**	**1,946**	**1,964**	**1,987**	**2,011**	**2,035**	**2,059**
Peak Load (MW)–95th Percentile										
System Peak (1 Hour)	3,576	3,669	3,736	3,793	3,847	3,905	3,965	4,026	4,086	4,151
Total Peak Load	**3,576**	**3,669**	**3,736**	**3,793**	**3,847**	**3,905**	**3,965**	**4,026**	**4,086**	**4,151**

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Billed Sales (MWh)–70th Percentile										
Residential	6,112,140	6,200,195	6,287,755	6,378,017	6,467,506	6,544,386	6,614,509	6,685,063	6,757,939	6,829,662
Commercial	4,561,364	4,605,150	4,647,240	4,692,068	4,739,417	4,784,329	4,827,637	4,873,585	4,922,833	4,971,401
Irrigation	2,081,259	2,093,648	2,104,780	2,115,037	2,126,900	2,137,034	2,146,010	2,152,899	2,161,682	2,169,546
Industrial	3,047,748	3,101,332	3,154,544	3,207,964	3,263,009	3,314,431	3,364,294	3,412,358	3,461,829	3,509,388
Additional Firm	1,006,800	1,004,100	1,004,100	998,800	998,800	1,004,100	1,004,100	998,800	998,800	993,500
System Sales	16,809,311	17,004,425	17,198,419	17,391,886	17,595,632	17,784,280	17,956,550	18,122,705	18,303,083	18,473,496
Total Sales	**16,809,311**	**17,004,425**	**17,198,419**	**17,391,886**	**17,595,632**	**17,784,280**	**17,956,550**	**18,122,705**	**18,303,083**	**18,473,496**
Generation Month Sales (MWh)–70th Percentile										
Residential	6,118,814	6,206,840	6,294,611	6,405,135	6,473,380	6,549,762	6,619,925	6,711,729	6,763,457	6,835,118
Commercial	4,563,863	4,607,563	4,649,803	4,707,547	4,741,992	4,786,824	4,830,276	4,889,591	4,925,621	4,974,352
Irrigation	2,081,265	2,093,654	2,104,785	2,115,098	2,126,905	2,137,039	2,146,014	2,152,960	2,161,686	2,169,550
Industrial	3,052,167	3,105,721	3,158,950	3,212,504	3,267,250	3,318,543	3,368,258	3,416,438	3,465,751	3,513,496
Additional Firm	1,006,800	1,004,100	1,004,100	998,800	998,800	1,004,100	1,004,100	998,800	998,800	993,500
System Sales	16,822,910	17,017,877	17,212,249	17,439,084	17,608,327	17,796,269	17,968,573	18,169,518	18,315,315	18,486,015
Total Sales	**16,822,910**	**17,017,877**	**17,212,249**	**17,439,084**	**17,608,327**	**17,796,269**	**17,968,573**	**18,169,518**	**18,315,315**	**18,486,015**
Loss	1,445,886	1,462,827	1,479,556	1,499,718	1,513,980	1,529,833	1,544,571	1,562,443	1,574,650	1,589,634
Required Generation	18,268,795	18,480,705	18,691,805	18,938,803	19,122,307	19,326,102	19,513,144	19,731,961	19,889,966	20,075,650
Average Load (aMW)–70th Percentile										
Residential	698	709	719	729	739	748	756	764	772	780
Commercial	521	526	531	536	541	546	551	557	562	568
Irrigation	238	239	240	241	243	244	245	245	247	248
Industrial	348	355	361	366	373	379	385	389	396	401
Additional Firm	115	115	115	114	114	115	115	114	114	113
Loss	165	167	169	171	173	175	176	178	180	181
System Load	2,085	2,110	2,134	2,156	2,183	2,206	2,228	2,246	2,271	2,292
Light Load	1,893	1,915	1,936	1,957	1,981	2,002	2,022	2,039	2,061	2,080
Heavy Load	2,237	2,263	2,288	2,313	2,342	2,366	2,382	2,402	2,428	2,452
Total Load	**2,085**	**2,110**	**2,134**	**2,156**	**2,183**	**2,206**	**2,228**	**2,246**	**2,271**	**2,292**
Peak Load (MW)–95th Percentile										
System Peak (1 Hour)	4,215	4,278	4,341	4,404	4,469	4,531	4,592	4,651	4,713	4,773
Total Peak Load	**4,215**	**4,278**	**4,341**	**4,404**	**4,469**	**4,531**	**4,592**	**4,651**	**4,713**	**4,773**

LOAD AND RESOURCE BALANCE DATA

Monthly Average Energy Load and Resource Balance

	1/2015	2/2015	3/2015	4/2015	5/2015	6/2015	7/2015	8/2015	9/2015	10/2015	11/2015	12/2015
Forecast EE	11	11	11	11	13	15	16	15	12	10	10	11
Load Forecast (70th% w/EE)	(1,800)	(1,724)	(1,575)	(1,549)	(1,734)	(2,079)	(2,498)	(2,156)	(1,785)	(1,541)	(1,573)	(1,914)
Total non-forecasted trended EE	0	0	0	0	0	0	0	0	0	0	0	0
Net Load Forecast (70th% w/ EE)	(1,800)	(1,724)	(1,575)	(1,549)	(1,734)	(2,079)	(2,498)	(2,156)	(1,785)	(1,541)	(1,573)	(1,914)
Existing Resources												
Total Coal	960	960	933	777	867	960	960	960	812	789	936	960
Total Gas	516	286	280	281	279	516	496	515	277	281	284	525
Hydro (70th%)—HCC	569	702	591	720	873	601	526	369	455	407	343	483
Hydro (70th%)—Other	217	291	237	263	314	328	279	210	224	219	202	208
Sho-Ban Water Lease	0	0	0	0	0	0	71	0	0	0	0	0
Total Hydro (70th%)	786	994	828	983	1,187	929	876	580	679	626	545	691
CSPP (PURPA)	202	244	248	303	299	301	258	219	241	223	205	198
PPAs												
Elkhorn Valley Wind	36	33	36	33	30	32	34	33	27	30	33	35
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	5	6	7	9	10	11	10	7	4	1	3	4
Clatskanie Exchange—Return	0	0	(20)	(20)	0	0	0	0	0	(20)	(20)	0
Total PPAs	**76**	**73**	**54**	**49**	**62**	**65**	**62**	**61**	**55**	**36**	**46**	**74**
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
Existing Resource Subtotal	2,538	2,556	2,342	2,393	2,694	2,771	2,651	2,334	2,063	1,955	2,015	2,447
Monthly Surplus/Deficit	738	832	767	844	960	692	153	178	278	414	442	534
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	738	832	767	844	960	692	153	178	278	414	442	534

Monthly Average Energy Load and Resource Balance (continued)

	1/2016	2/2016	3/2016	4/2016	5/2016	6/2016	7/2016	8/2016	9/2016	10/2016	11/2016	12/2016
Forecast EE	19	18	18	18	21	23	24	23	19	17	17	18
Load Forecast (70th% w/EE)	(1,854)	(1,761)	(1,624)	(1,594)	(1,782)	(2,128)	(2,568)	(2,218)	(1,833)	(1,585)	(1,617)	(1,954)
Total non-forecasted trended EE	7	7	7	7	8	9	9	9	7	7	7	7
Net Load Forecast (70th% w/ EE)	(1,847)	(1,754)	(1,618)	(1,587)	(1,775)	(2,120)	(2,559)	(2,209)	(1,825)	(1,579)	(1,610)	(1,947)
Existing Resources												
Total Coal	958	958	725	607	735	958	958	958	799	788	945	958
Total Gas	516	286	280	281	279	516	496	515	277	281	284	516
Hydro (70th%)—HCC	570	713	596	728	883	606	525	369	453	406	344	483
Hydro (70th%)—Other	218	307	243	265	316	328	279	210	224	219	202	208
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	787	1,019	839	994	1,198	934	804	579	677	625	545	690
CSPP (PURPA)	208	253	258	315	313	316	304	263	277	251	221	259
PPAs												
Elkhorn Valley Wind	36	33	36	33	30	32	34	33	27	30	33	35
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	71	67	67	60	52	54	52	54	51	55	63	70
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
Existing Resource Subtotal	2,539	2,583	2,168	2,257	2,578	2,779	2,614	2,369	2,080	1,999	2,058	2,493
Monthly Surplus/Deficit	692	829	551	670	803	659	55	159	255	421	448	546
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	692	829	551	670	803	659	55	159	255	421	448	546

Monthly Average Energy Load and Resource Balance (continued)

	1/2017	2/2017	3/2017	4/2017	5/2017	6/2017	7/2017	8/2017	9/2017	10/2017	11/2017	12/2017
Forecast EE	24	24	23	23	26	28	30	29	24	22	22	24
Load Forecast (70th% w/EE)	(1,884)	(1,802)	(1,649)	(1,618)	(1,808)	(2,159)	(2,606)	(2,251)	(1,861)	(1,609)	(1,642)	(1,980)
Total non-forecasted trended EE	19	19	18	18	20	22	24	22	19	17	17	19
Net Load Forecast (70th% w/ EE)	(1,865)	(1,784)	(1,632)	(1,600)	(1,788)	(2,137)	(2,583)	(2,229)	(1,842)	(1,592)	(1,625)	(1,961)
Existing Resources												
Total Coal	958	958	926	751	754	958	958	958	958	958	958	958
Total Gas	525	286	280	281	279	507	505	515	277	281	284	516
Hydro (70th%)—HCC	567	710	601	731	895	614	526	370	449	407	343	486
Hydro (70th%)—Other	215	311	240	268	318	329	279	211	224	219	193	203
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	782	1,021	841	999	1,213	943	805	581	673	626	536	689
CSPP (PURPA)	263	339	372	455	472	486	454	400	393	343	281	259
PPAs												
Elkhorn Valley Wind	36	33	36	33	30	32	34	33	27	30	33	35
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	71	67	67	60	52	54	52	54	51	55	63	70
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
Existing Resource Subtotal	2,598	2,671	2,485	2,546	2,770	2,949	2,773	2,507	2,352	2,263	2,121	2,492
Monthly Surplus/Deficit	733	888	854	946	982	812	191	278	511	671	496	531
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	733	888	854	946	982	812	191	278	511	671	496	531

Monthly Average Energy Load and Resource Balance (continued)

	1/2018	2/2018	3/2018	4/2018	5/2018	6/2018	7/2018	8/2018	9/2018	10/2018	11/2018	12/2018
Forecast EE	32	31	29	31	36	41	43	41	33	29	29	31
Load Forecast (70th% w/EE)	(1,906)	(1,821)	(1,667)	(1,635)	(1,826)	(2,180)	(2,631)	(2,274)	(1,880)	(1,626)	(1,660)	(2,003)
Total non-forecasted trended EE	29	29	27	28	33	37	40	37	31	26	26	29
Net Load Forecast (70th% w/ EE)	(1,876)	(1,792)	(1,640)	(1,606)	(1,793)	(2,142)	(2,592)	(2,237)	(1,850)	(1,600)	(1,633)	(1,974)
Existing Resources												
Total Coal	958	958	893	738	784	958	958	958	958	958	957	958
Total Gas	525	286	280	281	279	507	505	506	277	281	284	525
Hydro (70th%)—HCC	567	710	600	733	900	612	525	369	447	408	343	485
Hydro (70th%)—Other	216	309	234	270	319	329	279	211	224	220	192	200
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	783	1,019	834	1,003	1,219	941	804	580	671	628	535	685
CSPP (PURPA)	263	339	372	455	472	486	454	400	393	343	281	259
PPAs												
Elkhorn Valley Wind	36	33	36	33	30	32	34	33	27	30	33	35
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	71	67	67	60	52	54	52	54	51	55	63	70
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
Existing Resource Subtotal	2,599	2,669	2,445	2,537	2,806	2,947	2,772	2,497	2,350	2,264	2,120	2,497
Monthly Surplus/Deficit	722	877	806	931	1,013	805	180	260	500	664	486	522
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	722	877	806	931	1,013	805	180	260	500	664	486	522

Monthly Average Energy Load and Resource Balance (continued)

	1/2019	2/2019	3/2019	4/2019	5/2019	6/2019	7/2019	8/2019	9/2019	10/2019	11/2019	12/2019
Forecast EE	39	38	36	37	43	48	51	48	40	34	35	38
Load Forecast (70th% w/EE)	(1,926)	(1,838)	(1,683)	(1,650)	(1,842)	(2,198)	(2,654)	(2,294)	(1,898)	(1,642)	(1,677)	(2,024)
Total non-forecasted trended EE	41	40	38	40	47	52	55	52	43	37	37	40
Net Load Forecast (70th% w/ EE)	(1,885)	(1,798)	(1,645)	(1,610)	(1,795)	(2,146)	(2,598)	(2,242)	(1,855)	(1,606)	(1,640)	(1,983)
Existing Resources												
Total Coal	956	956	909	838	733	956	956	956	956	956	956	956
Total Gas	525	286	280	281	279	516	505	506	277	281	284	525
Hydro (70th%)—HCC	569	711	600	735	907	616	526	370	442	409	344	479
Hydro (70th%)—Other	215	302	221	263	321	330	280	211	224	221	186	193
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	784	1,012	821	998	1,227	946	806	581	666	629	530	671
CSPP (PURPA)	263	339	372	455	472	486	454	400	393	343	281	259
PPAs												
Elkhorn Valley Wind	36	33	36	33	30	32	34	33	27	30	33	35
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	71	67	67	60	52	54	52	54	51	55	63	70
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
Existing Resource Subtotal	2,598	2,660	2,448	2,632	2,764	2,959	2,773	2,497	2,343	2,264	2,113	2,481
Monthly Surplus/Deficit	713	863	802	1,021	969	814	175	255	488	659	473	498
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	713	863	802	1,021	969	814	175	255	488	659	473	498

Monthly Average Energy Load and Resource Balance (continued)

	1/2020	2/2020	3/2020	4/2020	5/2020	6/2020	7/2020	8/2020	9/2020	10/2020	11/2020	12/2020
Forecast EE	48	47	44	47	54	61	66	62	50	43	43	47
Load Forecast (70th% w/EE)	(1,946)	(1,839)	(1,700)	(1,667)	(1,860)	(2,221)	(2,681)	(2,318)	(1,919)	(1,659)	(1,693)	(2,047)
Total non-forecasted trended EE	47	45	43	45	53	59	64	60	48	42	42	45
Net Load Forecast (70th% w/ EE)	(1,899)	(1,794)	(1,657)	(1,622)	(1,808)	(2,161)	(2,617)	(2,258)	(1,870)	(1,618)	(1,652)	(2,001)
Existing Resources												
Total Coal	807	786	54	54	337	811	851	807	781	348	394	807
Total Gas	494	145	87	–	87	510	494	512	135	–	90	503
Hydro (70th%)—HCC	566	709	600	733	905	614	525	369	436	409	344	472
Hydro (70th%)—Other	213	291	218	261	320	329	279	210	222	220	186	193
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	779	1,000	818	994	1,224	943	804	579	658	628	529	665
CSPP (PURPA)	263	339	372	455	472	486	454	400	393	343	281	259
PPAs												
Elkhorn Valley Wind	36	33	36	33	30	32	34	33	27	30	33	35
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	71	67	67	60	52	54	52	54	51	55	63	70
Market Purchases	0	0	259	58	0	0	0	0	0	243	295	0
Existing Resource Subtotal	2,413	2,336	1,657	1,622	2,173	2,804	2,655	2,351	2,018	1,618	1,652	2,304
Monthly Surplus/Deficit	514	542	0	0	365	643	38	93	148	0	0	303
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	514	542	0	0	365	643	38	93	148	0	0	303

Monthly Average Energy Load and Resource Balance (continued)

	1/2021	2/2021	3/2021	4/2021	5/2021	6/2021	7/2021	8/2021	9/2021	10/2021	11/2021	12/2021
Forecast EE	55	54	51	54	63	71	76	71	58	49	50	54
Load Forecast (70th% w/EE)	(1,967)	(1,873)	(1,717)	(1,684)	(1,880)	(2,245)	(2,710)	(2,344)	(1,940)	(1,677)	(1,711)	(2,070)
Total non-forecasted trended EE	55	53	51	53	62	70	75	70	57	49	49	53
Net Load Forecast (70th% w/ EE)	(1,912)	(1,820)	(1,666)	(1,631)	(1,819)	(2,175)	(2,636)	(2,274)	(1,884)	(1,628)	(1,662)	(2,016)
Existing Resources												
Total Coal	753	732	–	–	283	756	797	753	726	294	407	753
Total Gas	494	145	87	–	87	510	494	512	135	–	90	494
Hydro (70th%)—HCC	564	707	589	731	903	611	524	367	430	409	344	469
Hydro (70th%)—Other	211	285	208	259	319	328	278	209	221	219	185	192
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	775	992	797	990	1,222	939	802	576	651	627	529	661
CSPP (PURPA)	263	339	372	455	472	486	454	400	393	343	281	259
PPAs												
Elkhorn Valley Wind	36	33	36	33	30	32	34	33	27	30	33	35
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	71	67	67	60	52	54	52	54	51	55	63	70
Market Purchases	0	0	345	126	0	0	37	0	0	309	293	0
Existing Resource Subtotal	2,355	2,274	1,666	1,631	2,116	2,746	2,636	2,294	1,957	1,628	1,662	2,237
Monthly Surplus/Deficit	443	455	0	0	297	571	0	20	73	0	0	221
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	443	455	0	0	297	571	0	20	73	0	0	221

Monthly Average Energy Load and Resource Balance (continued)

	1/2022	2/2022	3/2022	4/2022	5/2022	6/2022	7/2022	8/2022	9/2022	10/2022	11/2022	12/2022
Forecast EE	62	60	57	60	70	79	85	79	64	55	56	60
Load Forecast (70th% w/EE)	(1,992)	(1,895)	(1,738)	(1,704)	(1,902)	(2,270)	(2,740)	(2,371)	(1,964)	(1,698)	(1,733)	(2,098)
Total non-forecasted trended EE	64	63	60	62	73	82	88	82	67	57	58	63
Net Load Forecast (70th% w/ EE)	(1,928)	(1,833)	(1,679)	(1,642)	(1,829)	(2,188)	(2,652)	(2,288)	(1,897)	(1,640)	(1,675)	(2,035)
Existing Resources												
Total Coal	753	732	–	–	283	756	797	753	726	294	371	753
Total Gas	503	145	87	–	87	510	494	512	135	–	90	494
Hydro (70th%)—HCC	562	705	587	728	901	608	522	366	425	409	343	467
Hydro (70th%)—Other	210	286	203	257	318	327	278	208	220	218	184	191
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	771	991	790	986	1,219	935	800	574	645	627	528	658
CSPP (PURPA)	263	339	372	455	472	486	454	400	393	343	281	259
PPAs												
Elkhorn Valley Wind	36	33	36	33	30	32	34	33	27	30	33	35
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	71	67	67	60	52	54	52	54	51	55	63	70
Market Purchases	0	0	363	142	0	0	56	0	0	322	344	0
Existing Resource Subtotal	2,360	2,273	1,679	1,642	2,113	2,743	2,652	2,292	1,950	1,640	1,675	2,234
Monthly Surplus/Deficit	433	441	0	0	284	555	0	3	53	0	(0)	199
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	433	441	0	0	284	555	0	3	53	0	(0)	199

Monthly Average Energy Load and Resource Balance (continued)

	1/2023	2/2023	3/2023	4/2023	5/2023	6/2023	7/2023	8/2023	9/2023	10/2023	11/2023	12/2023
Forecast EE	68	67	63	66	77	87	93	87	71	61	61	67
Load Forecast (70th% w/EE)	(2,019)	(1,918)	(1,760)	(1,725)	(1,923)	(2,294)	(2,769)	(2,397)	(1,987)	(1,719)	(1,755)	(2,128)
Total non-forecasted trended EE	75	73	69	72	84	95	102	95	77	66	67	73
Net Load Forecast (70th% w/ EE)	(1,944)	(1,845)	(1,691)	(1,653)	(1,839)	(2,199)	(2,667)	(2,302)	(1,910)	(1,652)	(1,688)	(2,055)
Existing Resources												
Total Coal	753	732	–	–	283	756	797	753	726	294	385	753
Total Gas	503	145	87	–	87	501	503	512	135	–	90	494
Hydro (70th%)—HCC	559	703	586	726	899	605	521	364	419	409	344	459
Hydro (70th%)—Other	208	266	203	256	316	326	277	207	218	217	183	190
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	767	969	789	982	1,215	931	798	571	637	626	527	649
CSPP (PURPA)	263	339	372	455	472	486	454	400	393	343	281	259
PPAs												
Elkhorn Valley Wind	36	33	36	33	30	32	34	33	27	30	33	35
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	71	67	67	60	52	54	52	54	51	55	63	70
Market Purchases	0	0	377	156	0	0	64	12	0	335	343	0
Existing Resource Subtotal	2,356	2,251	1,691	1,653	2,109	2,730	2,667	2,302	1,942	1,652	1,688	2,225
Monthly Surplus/Deficit	413	406	0	0	270	531	0	0	32	0	(0)	170
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	413	406	0	0	270	531	0	0	32	0	(0)	170

Monthly Average Energy Load and Resource Balance (continued)

	1/2024	2/2024	3/2024	4/2024	5/2024	6/2024	7/2024	8/2024	9/2024	10/2024	11/2024	12/2024
Forecast EE	75	73	69	72	84	95	102	95	77	66	67	73
Load Forecast (70th% w/EE)	(2,046)	(1,925)	(1,783)	(1,747)	(1,947)	(2,322)	(2,803)	(2,427)	(2,013)	(1,741)	(1,778)	(2,159)
Total non-forecasted trended EE	86	83	79	82	96	109	117	109	88	76	77	83
Net Load Forecast (70th% w/ EE)	(1,960)	(1,842)	(1,703)	(1,665)	(1,851)	(2,213)	(2,687)	(2,318)	(1,925)	(1,665)	(1,702)	(2,075)
Existing Resources												
Total Coal	753	732	–	–	283	756	797	753	726	294	402	753
Total Gas	503	145	87	–	87	510	503	503	135	–	90	503
Hydro (70th%)—HCC	556	696	585	724	897	602	519	362	412	409	343	450
Hydro (70th%)—Other	208	254	204	252	316	325	276	206	217	216	183	189
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	764	950	789	976	1,213	927	795	568	628	625	526	639
CSPP (PURPA)	263	339	372	455	472	486	454	400	393	343	281	259
PPAs												
Elkhorn Valley Wind	36	33	36	33	30	32	34	33	27	30	33	35
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	71	67	67	60	52	54	52	54	51	55	63	70
Market Purchases	0	0	389	173	0	0	86	41	0	348	341	0
Existing Resource Subtotal	2,353	2,232	1,703	1,665	2,107	2,735	2,687	2,318	1,934	1,665	1,702	2,224
Monthly Surplus/Deficit	392	389	0	0	256	522	0	0	9	0	(0)	149
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	392	389	0	0	256	522	0	0	9	0	(0)	149

Monthly Average Energy Load and Resource Balance (continued)

	1/2025	2/2025	3/2025	4/2025	5/2025	6/2025	7/2025	8/2025	9/2025	10/2025	11/2025	12/2025
Forecast EE	80	78	74	77	88	99	107	100	81	71	72	78
Load Forecast (70th% w/EE)	(2,071)	(1,964)	(1,803)	(1,767)	(1,969)	(2,349)	(2,837)	(2,457)	(2,037)	(1,761)	(1,799)	(2,186)
Total non-forecasted trended EE	97	94	89	92	106	119	128	120	98	85	87	94
Net Load Forecast (70th% w/ EE)	(1,974)	(1,870)	(1,714)	(1,675)	(1,864)	(2,230)	(2,709)	(2,337)	(1,940)	(1,676)	(1,713)	(2,092)
Existing Resources												
Total Coal	753	732	–	–	283	756	797	753	726	294	419	753
Total Gas	494	145	87	–	87	510	512	503	135	–	90	503
Hydro (70th%)—HCC	554.8	693.9	583.8	722.3	895.1	598.3	518.1	361.0	407.5	401.0	344.3	446.8
Hydro (70th%)—Other	206.5	242.5	202.4	250.8	315.1	324.5	275.2	204.8	214.9	214.9	181.7	187.3
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	761	936	786	973	1,210	923	793	566	622	616	526	634
CSPP (PURPA)	263	339	372	455	472	486	454	400	393	341	278	257
PPAs												
Elkhorn Valley Wind	36	33	36	33	30	32	34	33	27	30	33	35
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	71	67	67	60	52	54	52	54	51	55	63	70
Market Purchases	0	0	402	187	0	0	101	62	12	371	338	0
Existing Resource Subtotal	2,342	2,219	1,714	1,675	2,104	2,730	2,709	2,337	1,940	1,676	1,713	2,217
Monthly Surplus/Deficit	367	349	0	0	241	500	0	0	0	0	(0)	124
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	567	549	200	500	741	1,000	500	500	500	200	200	324

Monthly Average Energy Load and Resource Balance (continued)

	1/2026	2/2026	3/2026	4/2026	5/2026	6/2026	7/2026	8/2026	9/2026	10/2026	11/2026	12/2026
Forecast EE	86	83	79	81	92	103	111	104	85	75	77	83
Load Forecast (70th% w/EE)	(2,095)	(1,985)	(1,823)	(1,787)	(1,991)	(2,376)	(2,871)	(2,486)	(2,062)	(1,781)	(1,820)	(2,213)
Total non-forecasted trended EE	108	105	100	102	116	130	140	131	108	94	97	105
Net Load Forecast (70th% w/ EE)	(1,988)	(1,880)	(1,724)	(1,685)	(1,876)	(2,246)	(2,731)	(2,355)	(1,954)	(1,687)	(1,723)	(2,108)
Existing Resources												
Total Coal	651	651	–	–	210	651	651	651	651	294	304	651
Total Gas	494	145	87	–	87	510	494	512	135	–	90	512
Hydro (70th%)—HCC	553	689	583	720	893	597	517	359	403	401	344	446
Hydro (70th%)—Other	206	223	200	246	314	323	274	204	214	214	181	187
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	759	912	783	966	1,207	919	791	563	617	615	525	633
CSPP (PURPA)	260	336	365	448	467	484	452	398	390	338	274	254
PPAs												
Elkhorn Valley Wind	36	33	36	33	30	32	34	33	27	30	33	35
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	71	67	67	60	52	54	52	54	51	55	63	70
Market Purchases	0	0	422	210	0	0	257	177	111	386	336	0
Existing Resource Subtotal	2,234	2,110	1,724	1,685	2,024	2,618	2,697	2,355	1,954	1,687	1,591	2,119
Monthly Surplus/Deficit	246	230	0	0	148	372	(34)	0	0	0	(132)	11
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	446	430	200	500	648	872	466	500	500	200	68	211

Monthly Average Energy Load and Resource Balance (continued)

	1/2027	2/2027	3/2027	4/2027	5/2027	6/2027	7/2027	8/2027	9/2027	10/2027	11/2027	12/2027
Forecast EE	91	88	84	85	95	107	116	108	89	79	81	88
Load Forecast (70th% w/EE)	(2,120)	(2,006)	(1,843)	(1,806)	(2,013)	(2,403)	(2,904)	(2,515)	(2,086)	(1,801)	(1,840)	(2,241)
Total non-forecasted trended EE	119	116	110	112	126	141	153	143	118	104	107	116
Net Load Forecast (70th% w/ EE)	(2,001)	(1,890)	(1,733)	(1,694)	(1,887)	(2,262)	(2,751)	(2,372)	(1,968)	(1,698)	(1,733)	(2,124)
Existing Resources												
Total Coal	651	651	–	–	210	651	651	651	651	294	304	651
Total Gas	503	145	87	–	87	510	494	512	135	–	90	494
Hydro (70th%)—HCC	551	679	582	719	892	595	515	358	398	401	344	445
Hydro (70th%)—Other	205	211	199	243	313	322	274	203	211	213	180	185
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	756	891	780	962	1,205	917	789	561	610	614	524	630
CSPP (PURPA)	257	333	365	448	467	484	452	398	390	338	274	254
PPAs												
Elkhorn Valley Wind	36	33	36	33	30	32	34	33	27	30	33	35
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	71	67	67	60	52	54	52	54	51	55	63	70
Market Purchases	0	0	434	224	0	0	254	197	132	397	334	26
Existing Resource Subtotal	2,237	2,086	1,733	1,694	2,021	2,616	2,692	2,372	1,968	1,698	1,588	2,124
Monthly Surplus/Deficit	236	196	0	0	134	354	(59)	0	0	0	(146)	0
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	436	396	200	500	634	854	441	500	500	200	54	200

Monthly Average Energy Load and Resource Balance (continued)

	1/2028	2/2028	3/2028	4/2028	5/2028	6/2028	7/2028	8/2028	9/2028	10/2028	11/2028	12/2028
Forecast EE	92	88	89	99	111	120	112	93	82	85	92	92
Load Forecast (70th% w/EE)	(2,010)	(1,864)	(1,826)	(2,035)	(2,429)	(2,937)	(2,544)	(2,111)	(1,822)	(1,861)	(2,268)	(2,010)
Total non-forecasted trended EE	128	122	123	137	153	166	156	129	114	118	128	128
Net Load Forecast (70th% w/ EE)	(1,881)	(1,742)	(1,703)	(1,898)	(2,276)	(2,771)	(2,388)	(1,982)	(1,707)	(1,743)	(2,140)	(1,881)
Existing Resources												
Total Coal	651	–	–	210	651	651	651	651	294	304	651	651
Total Gas	145	87	–	87	501	503	512	135	–	90	494	145
Hydro (70th%)—HCC	675	581	717	890	593	514	357	393	402	344	442	675
Hydro (70th%)—Other	210	194	244	313	321	273	201	210	212	178	184	210
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	885	775	961	1,203	915	787	558	603	614	523	626	885
CSPP (PURPA)	333	365	448	467	484	452	398	390	338	274	254	333
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	9	9	8	7	7	8	8	8	10	9	9	9
Neal Hot Springs Geothermal	24	22	19	14	15	11	13	16	15	20	26	24
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	33	31	27	22	22	18	21	24	25	30	35	33
Market Purchases	0	441	267	0	0	249	249	179	405	331	80	0
Existing Resource Subtotal	2,046	1,699	1,703	1,989	2,573	2,659	2,388	1,982	1,676	1,551	2,140	2,046
Monthly Surplus/Deficit	165	(43)	0	91	297	(112)	0	0	(31)	(192)	0	165
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	500	500	500	500	500	500	200	200	200	200
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	500	500	500	500	500	500	200	200	200	200
Monthly Surplus/Deficit	365	157	500	591	797	388	500	500	169	8	200	365

Monthly Average Energy Load and Resource Balance (continued)

	1/2029	2/2029	3/2029	4/2029	5/2029	6/2029	7/2029	8/2029	9/2029	10/2029	11/2029	12/2029
Forecast EE	99	97	92	92	102	114	123	116	96	86	89	97
Load Forecast (70th% w/EE)	(2,170)	(2,050)	(1,885)	(1,847)	(2,058)	(2,457)	(2,972)	(2,575)	(2,136)	(1,843)	(1,883)	(2,294)
Total non-forecasted trended EE	144	140	133	134	148	165	179	168	140	124	129	140
Net Load Forecast (70th% w/ EE)	(2,026)	(1,910)	(1,752)	(1,713)	(1,911)	(2,292)	(2,793)	(2,407)	(1,996)	(1,718)	(1,753)	(2,154)
Existing Resources												
Total Coal	651	651	–	–	210	651	651	651	651	294	323	651
Total Gas	503	145	87	–	87	501	503	503	135	–	90	503
Hydro (70th%)—HCC	547	672	580	715	888	591	513	355	384	401	344	441
Hydro (70th%)—Other	204	208	193	240	312	320	272	200	209	211	178	182
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	751	880	773	955	1,201	911	785	556	593	612	522	623
CSPP (PURPA)	247	322	352	431	452	469	442	391	380	327	261	241
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	34	33	31	27	22	22	18	21	24	25	30	35
Market Purchases	0	0	440	300	0	0	245	286	214	403	329	102
Existing Resource Subtotal	2,186	2,031	1,683	1,713	1,972	2,555	2,643	2,407	1,996	1,661	1,553	2,154
Monthly Surplus/Deficit	159	121	(68)	0	61	263	(149)	0	0	(57)	(200)	0
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	359	321	132	500	561	763	351	500	500	143	0	200

Monthly Average Energy Load and Resource Balance (continued)

	1/2030	2/2030	3/2030	4/2030	5/2030	6/2030	7/2030	8/2030	9/2030	10/2030	11/2030	12/2030
Forecast EE	104	102	97	97	106	118	129	121	101	90	94	102
Load Forecast (70th% w/EE)	(2,194)	(2,070)	(1,904)	(1,866)	(2,080)	(2,483)	(3,004)	(2,603)	(2,160)	(1,862)	(1,902)	(2,320)
Total non-forecasted trended EE	152	147	140	140	154	172	187	175	146	130	136	147
Net Load Forecast (70th% w/ EE)	(2,043)	(1,922)	(1,764)	(1,725)	(1,926)	(2,312)	(2,817)	(2,428)	(2,014)	(1,732)	(1,767)	(2,172)
Existing Resources												
Total Coal	651	488	–	–	210	651	651	651	651	210	439	651
Total Gas	503	145	87	–	87	510	503	503	90	–	–	503
Hydro (70th%)—HCC	546	670	579	713	887	590	511	355	379	401	345	438
Hydro (70th%)—Other	202	207	194	233	312	318	271	200	208	210	177	181
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	748	877	773	946	1,198	908	783	555	587	612	521	620
CSPP (PURPA)	244	319	349	431	452	459	435	386	373	320	251	233
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	34	33	31	27	22	22	18	21	24	25	30	35
Market Purchases	0	60	438	321	0	0	242	305	289	402	327	131
Existing Resource Subtotal	2,180	1,922	1,677	1,725	1,969	2,551	2,631	2,421	2,014	1,569	1,567	2,172
Monthly Surplus/Deficit	137	0	(87)	0	43	240	(186)	(7)	0	(163)	(200)	0
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	337	200	113	500	543	740	314	493	500	37	0	200

Monthly Average Energy Load and Resource Balance (continued)

	1/2031	2/2031	3/2031	4/2031	5/2031	6/2031	7/2031	8/2031	9/2031	10/2031	11/2031	12/2031
Forecast EE	110	107	101	101	110	123	134	126	105	94	98	107
Load Forecast (70th% w/EE)	(2,216)	(2,088)	(1,922)	(1,883)	(2,099)	(2,507)	(3,033)	(2,629)	(2,182)	(1,880)	(1,920)	(2,344)
Total non-forecasted trended EE	159	154	147	146	160	178	194	182	152	136	142	154
Net Load Forecast (70th% w/ EE)	(2,057)	(1,934)	(1,775)	(1,737)	(1,940)	(2,329)	(2,839)	(2,447)	(2,030)	(1,744)	(1,778)	(2,189)
Existing Resources												
Total Coal	651	488	–	–	210	651	651	651	651	210	247	651
Total Gas	494	145	87	–	87	510	512	503	90	–	–	503
Hydro (70th%)—HCC	544	669	578	711	885	588	510	355	374	401	344	435
Hydro (70th%)—Other	202	205	193	226	311	317	271	199	206	209	176	181
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	746	874	770	937	1,196	905	781	553	580	610	521	616
CSPP (PURPA)	213	249	279	352	378	395	388	351	329	269	188	171
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	34	33	31	27	22	22	18	21	24	25	30	35
Market Purchases	0	145	436	420	47	0	238	303	302	400	324	214
Existing Resource Subtotal	2,137	1,934	1,603	1,737	1,940	2,484	2,588	2,382	1,976	1,515	1,309	2,189
Monthly Surplus/Deficit	80	0	(172)	0	0	155	(251)	(65)	(54)	(229)	(470)	0
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	270	270	270	270	270	270	270	270	270	270	270	270
New Resource Subtotal	470	470	470	770	770	770	770	770	770	470	470	470
Monthly Surplus/Deficit	550	470	298	770	770	925	519	705	716	241	0	470

Monthly Average Energy Load and Resource Balance (continued)

	1/2032	2/2032	3/2032	4/2032	5/2032	6/2032	7/2032	8/2032	9/2032	10/2032	11/2032	12/2032
Forecast EE	114	111	106	105	114	128	140	131	109	98	103	111
Load Forecast (70th% w/EE)	(2,236)	(2,087)	(1,939)	(1,900)	(2,118)	(2,530)	(3,062)	(2,654)	(2,203)	(1,897)	(1,938)	(2,367)
Total non-forecasted trended EE	166	161	153	152	166	185	202	189	158	142	148	161
Net Load Forecast (70th% w/ EE)	(2,071)	(1,926)	(1,786)	(1,747)	(1,953)	(2,346)	(2,860)	(2,465)	(2,045)	(1,756)	(1,790)	(2,206)
Existing Resources												
Total Coal	651	488	–	–	210	651	651	651	651	210	261	651
Total Gas	494	145	87	–	87	510	494	512	90	–	–	494
Hydro (70th%)—HCC	543	667	576	709	883	586	509	353	369	401	344	434
Hydro (70th%)—Other	201	204	191	222	310	316	270	198	205	208	175	179
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	743	871	767	931	1,193	902	779	551	574	610	520	613
CSPP (PURPA)	171	232	265	336	371	388	382	346	323	263	187	170
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	34	33	31	27	22	22	18	21	24	25	30	35
Market Purchases	0	156	434	435	70	0	234	299	302	399	322	243
Existing Resource Subtotal	2,094	1,926	1,583	1,729	1,953	2,474	2,558	2,380	1,964	1,507	1,319	2,206
Monthly Surplus/Deficit	23	0	(202)	(18)	0	128	(303)	(85)	(82)	(248)	(470)	0
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	270	270	270	270	270	270	270	270	270	270	270	270
New Resource Subtotal	470	470	470	770	770	770	770	770	770	470	470	470
Monthly Surplus/Deficit	493	470	268	752	770	898	467	685	688	222	(0)	470

Monthly Average Energy Load and Resource Balance (continued)

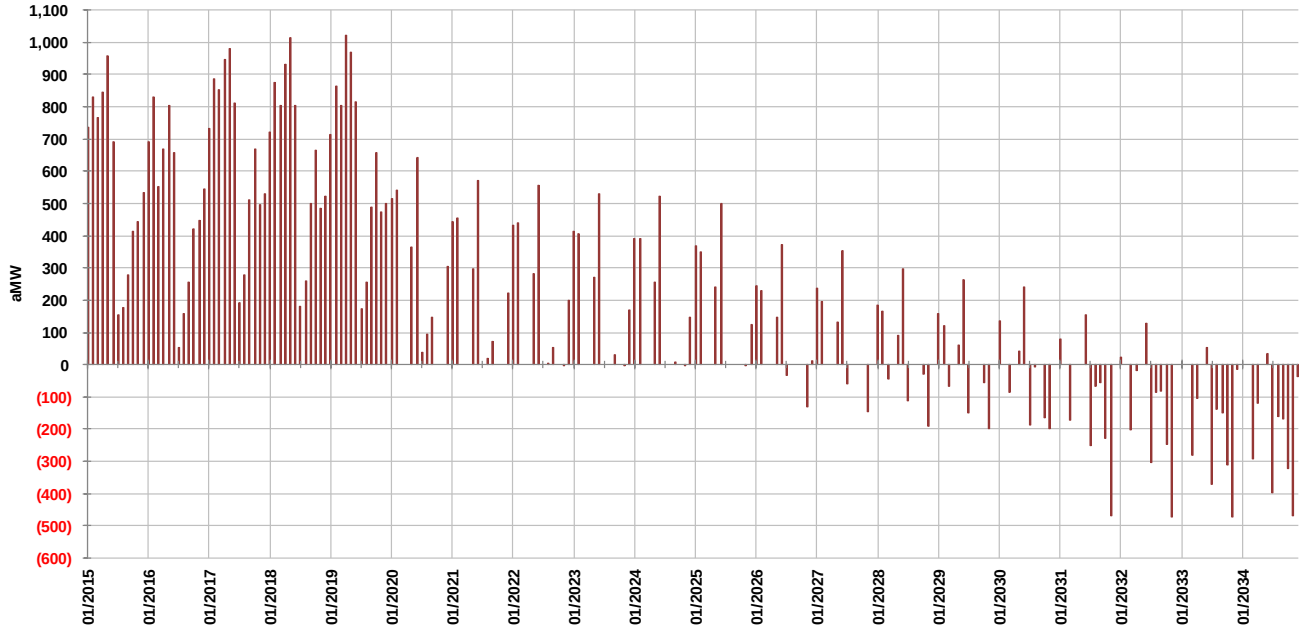
	1/2033	2/2033	3/2033	4/2033	5/2033	6/2033	7/2033	8/2033	9/2033	10/2033	11/2033	12/2033
Forecast EE	119	116	110	109	118	132	145	136	113	102	107	116
Load Forecast (70th% w/EE)	(2,259)	(2,124)	(1,957)	(1,918)	(2,139)	(2,556)	(3,093)	(2,682)	(2,227)	(1,916)	(1,957)	(2,392)
Total non-forecasted trended EE	173	168	159	158	171	191	209	196	164	147	154	168
Net Load Forecast (70th% w/ EE)	(2,086)	(1,956)	(1,798)	(1,759)	(1,968)	(2,364)	(2,884)	(2,485)	(2,062)	(1,769)	(1,802)	(2,224)
Existing Resources												
Total Coal	651	488	–	–	210	651	651	651	651	210	313	651
Total Gas	503	145	87	–	87	510	494	512	90	–	–	494
Hydro (70th%)—HCC	542	665	571	707	882	584	507	352	364	401	345	432
Hydro (70th%)—Other	199	203	189	220	309	314	269	197	204	208	174	178
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	741	868	760	927	1,191	899	777	549	568	608	520	610
CSPP (PURPA)	130	175	208	268	319	335	343	319	280	220	151	134
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	34	33	31	27	22	22	18	21	24	25	30	35
Market Purchases	28	247	433	433	139	0	230	296	302	396	319	285
Existing Resource Subtotal	2,086	1,956	1,519	1,656	1,968	2,418	2,512	2,347	1,915	1,460	1,332	2,209
Monthly Surplus/Deficit	0	0	(279)	(104)	0	54	(371)	(138)	(148)	(309)	(470)	(16)
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	270	270	270	270	270	270	270	270	270	270	270	270
New Resource Subtotal	470	470	470	770	770	770	770	770	770	470	470	470
Monthly Surplus/Deficit	470	470	191	666	770	824	399	632	622	161	(0)	454

Monthly Average Energy Load and Resource Balance (continued)

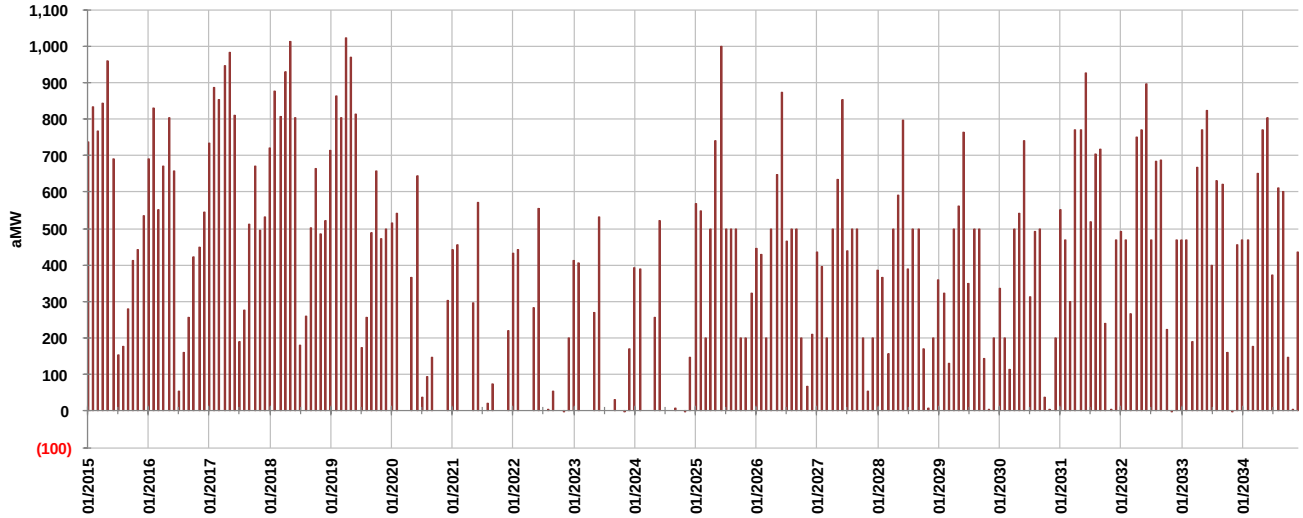
	1/2034	2/2034	3/2034	4/2034	5/2034	6/2034	7/2034	8/2034	9/2034	10/2034	11/2034	12/2034
Forecast EE	124	120	114	113	122	136	149	140	117	105	111	120
Load Forecast (70th% w/EE)	(2,280)	(2,142)	(1,974)	(1,935)	(2,159)	(2,579)	(3,123)	(2,708)	(2,249)	(1,934)	(1,974)	(2,416)
Total non-forecasted trended EE	179	174	166	164	177	198	217	203	170	153	161	174
Net Load Forecast (70th% w/ EE)	(2,101)	(1,968)	(1,808)	(1,771)	(1,981)	(2,382)	(2,906)	(2,505)	(2,079)	(1,781)	(1,814)	(2,242)
Existing Resources												
Total Coal	651	488	–	–	210	651	651	651	651	210	327	651
Total Gas	503	145	87	–	87	510	494	512	90	–	–	494
Hydro (70th%)—HCC	542	664	569	706	881	582	506	350	359	401	345	432
Hydro (70th%)—Other	197	200	187	218	308	313	269	196	203	207	173	177
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	739	864	756	924	1,189	896	775	546	562	607	518	609
CSPP (PURPA)	130	175	208	268	319	335	343	319	280	220	151	134
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange—Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange—Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	34	33	31	27	22	22	18	21	24	25	30	35
Market Purchases	44	262	433	433	154	0	230	296	302	396	319	285
Existing Resource Subtotal	2,101	1,968	1,515	1,653	1,981	2,415	2,510	2,345	1,909	1,459	1,344	2,207
Monthly Surplus/Deficit	0	0	(293)	(118)	0	33	(396)	(160)	(170)	(322)	(470)	(35)
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	270	270	270	270	270	270	270	270	270	270	270	270
New Resource Subtotal	470	470	470	770	770	770	770	770	770	470	470	470
Monthly Surplus/Deficit	470	470	177	652	770	803	374	610	600	148	0	435

Monthly Average Energy Surplus/Deficit Charts

Average energy monthly surpluses and deficits with existing DSM and existing resources



Average energy monthly surpluses and deficits with existing DSM, existing resources, IRP DSM, and IRP Resources



Peak-Hour Load and Resource Balance

	1/2015	2/2015	3/2015	4/2015	5/2015	6/2015	7/2015	8/2015	9/2015	10/2015	11/2015	12/2015
Load Forecast (95th% w/no DSM)	(2,343)	(2,412)	(2,137)	(2,039)	(2,697)	(3,181)	(3,597)	(3,044)	(2,918)	(2,141)	(2,245)	(2,637)
Existing DSM (EE)	12	12	10	12	15	18	21	15	17	8	12	12
Load Forecast (95th% w/DSM and EE)	(2,330)	(2,400)	(2,128)	(2,027)	(2,682)	(3,163)	(3,576)	(3,029)	(2,901)	(2,133)	(2,233)	(2,625)
Non-forecasted trended EE	0	0	0	0	0	0	0	0	0	0	0	0
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,330)	(2,400)	(2,128)	(2,027)	(2,682)	(2,773)	(3,186)	(2,692)	(2,901)	(2,133)	(2,233)	(2,625)
Existing Resources												
Total Coal	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	1,087	1,078	1,003	1,072	1,119	995	1,000	724	789	878	709	802
Hydro (90th%)—Other	207	209	187	204	303	313	281	208	215	214	200	207
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,294	1,287	1,190	1,276	1,422	1,307	1,281	932	1,004	1,092	909	1,009
CSPP (PURPA)	72	74	77	109	150	157	156	147	135	107	79	75
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	5	6	7	9	10	11	10	7	4	1	3	4
Clatskanie Exchange– Return	0	0	(20)	(20)	0	0	0	0	0	(20)	(20)	0
Total PPAs	44	44	23	21	37	38	33	33	33	11	18	44
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
Existing Resource Subtotal	3,147	3,141	3,027	3,143	3,345	3,240	3,207	2,849	2,909	2,947	2,743	2,865
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	817	742	899	1,116	663	467	21	157	8	814	510	239

Peak-Hour Load and Resource Balance (continued)

	1/2016	2/2016	3/2016	4/2016	5/2016	6/2016	7/2016	8/2016	9/2016	10/2016	11/2016	12/2016
Load Forecast (95th% w/no DSM)	(2,419)	(2,458)	(2,201)	(2,102)	(2,771)	(3,294)	(3,695)	(3,147)	(3,018)	(2,202)	(2,295)	(2,681)
Existing DSM (EE)	19	21	20	20	24	28	26	25	25	20	14	18
Load Forecast (95th% w/DSM and EE)	(2,400)	(2,437)	(2,181)	(2,082)	(2,748)	(3,266)	(3,669)	(3,122)	(2,992)	(2,183)	(2,281)	(2,663)
Non-forecasted trended EE	7	8	8	8	9	11	10	10	10	8	5	7
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,393)	(2,429)	(2,173)	(2,075)	(2,738)	(2,865)	(3,270)	(2,775)	(2,982)	(2,175)	(2,276)	(2,656)
Existing Resources												
Total Coal	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	1,086	1,094	1,003	1,073	1,133	993	1,000	722	785	880	710	801
Hydro (90th%)—Other	207	210	187	204	303	312	281	208	215	215	200	207
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,292	1,304	1,189	1,277	1,437	1,305	1,281	930	1,000	1,095	910	1,008
CSPP (PURPA)	72	74	88	120	170	221	220	211	192	139	111	77
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	39	38	36	32	27	27	23	26	29	30	35	40
Market Purchases	0	0	0	0	0	0	8	0	25	0	0	0
Existing Resource Subtotal	3,140	3,153	3,051	3,167	3,370	3,291	3,270	2,904	2,982	3,000	2,792	2,861
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	748	724	877	1,092	632	426	0	129	0	825	516	206

Peak-Hour Load and Resource Balance (continued)

	1/2017	2/2017	3/2017	4/2017	5/2017	6/2017	7/2017	8/2017	9/2017	10/2017	11/2017	12/2017
Load Forecast (95th% w/no DSM)	(2,453)	(2,498)	(2,227)	(2,130)	(2,819)	(3,356)	(3,773)	(3,205)	(3,072)	(2,236)	(2,329)	(2,714)
Existing DSM (EE)	27	26	23	27	31	36	36	33	30	27	24	28
Load Forecast (95th% w/DSM and EE)	(2,426)	(2,472)	(2,204)	(2,103)	(2,788)	(3,320)	(3,736)	(3,172)	(3,042)	(2,209)	(2,305)	(2,686)
Non-forecasted trended EE	21	20	18	21	25	28	28	26	23	21	19	22
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,405)	(2,452)	(2,185)	(2,083)	(2,763)	(2,902)	(3,318)	(2,809)	(3,018)	(2,189)	(2,286)	(2,665)
Existing Resources												
Total Coal	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	1,083	1,098	995	1,089	1,143	994	1,000	722	780	880	712	794
Hydro (90th%)—Other	204	209	186	205	305	313	282	208	216	215	196	202
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,286	1,307	1,181	1,295	1,448	1,306	1,282	930	996	1,095	907	997
CSPP (PURPA)	74	76	203	235	375	406	405	396	359	232	204	77
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	39	38	36	32	27	27	23	26	29	30	35	40
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
Existing Resource Subtotal	3,137	3,159	3,156	3,299	3,587	3,477	3,447	3,089	3,121	3,094	2,883	2,850
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	732	706	971	1,216	823	575	129	280	102	906	597	186

Peak-Hour Load and Resource Balance (continued)

	1/2018	2/2018	3/2018	4/2018	5/2018	6/2018	7/2018	8/2018	9/2018	10/2018	11/2018	12/2018
Load Forecast (95th% w/no DSM)	(2,468)	(2,518)	(2,246)	(2,143)	(2,861)	(3,403)	(3,847)	(3,255)	(3,118)	(2,263)	(2,347)	(2,739)
Existing DSM (EE)	35	35	33	34	42	47	54	50	41	35	34	36
Load Forecast (95th% w/DSM and EE)	(2,433)	(2,483)	(2,213)	(2,109)	(2,820)	(3,356)	(3,793)	(3,205)	(3,076)	(2,228)	(2,313)	(2,703)
Non-forecasted trended EE	32	32	31	31	38	44	50	46	38	32	31	33
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,401)	(2,451)	(2,182)	(2,078)	(2,781)	(2,922)	(3,353)	(2,822)	(3,038)	(2,196)	(2,282)	(2,670)
Existing Resources												
Total Coal	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	1,077	1,108	991	1,090	1,147	992	1,000	720	774	878	711	791
Hydro (90th%)—Other	204	208	186	205	305	313	281	208	216	216	195	200
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,281	1,316	1,177	1,295	1,453	1,305	1,281	928	990	1,094	906	991
CSPP (PURPA)	74	76	203	235	375	406	405	396	359	232	204	77
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	39	38	36	32	27	27	23	26	29	30	35	40
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
Existing Resource Subtotal	3,131	3,168	3,153	3,300	3,591	3,476	3,446	3,087	3,114	3,094	2,882	2,845
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	731	716	971	1,221	810	554	93	265	77	898	600	175

Peak-Hour Load and Resource Balance (continued)

	1/2019	2/2019	3/2019	4/2019	5/2019	6/2019	7/2019	8/2019	9/2019	10/2019	11/2019	12/2019
Load Forecast (95th% w/no DSM)	(2,494)	(2,533)	(2,272)	(2,160)	(2,900)	(3,447)	(3,907)	(3,287)	(3,162)	(2,284)	(2,372)	(2,763)
Existing DSM (EE)	38	33	42	34	51	60	61	53	55	38	41	40
Load Forecast (95th% w/DSM and EE)	(2,456)	(2,500)	(2,231)	(2,127)	(2,849)	(3,387)	(3,847)	(3,234)	(3,108)	(2,246)	(2,332)	(2,723)
Non-forecasted trended EE	41	36	45	36	54	65	65	57	59	41	44	43
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,415)	(2,464)	(2,186)	(2,090)	(2,795)	(2,932)	(3,391)	(2,841)	(3,049)	(2,205)	(2,288)	(2,681)
Existing Resources												
Total Coal	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021	1,021
Total Gas	716	716	716	716	716	716	716	716	716	716	716	716
Hydro (90th%)—HCC	1,077	1,123	977	1,088	1,155	996	1,000	720	769	880	712	772
Hydro (90th%)—Other	203	208	195	204	306	314	281	208	216	217	189	190
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,280	1,331	1,172	1,293	1,462	1,309	1,281	928	985	1,098	902	961
CSPP (PURPA)	74	76	203	235	375	406	405	396	359	232	204	77
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	39	38	36	32	27	27	23	26	29	30	35	40
Market Purchases	0	0	0	0	0	0	0	0	0	0	0	0
Existing Resource Subtotal	3,131	3,183	3,147	3,297	3,600	3,480	3,446	3,087	3,109	3,097	2,878	2,815
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	716	718	962	1,207	805	548	55	246	60	892	590	134

Peak-Hour Load and Resource Balance (continued)

	1/2020	2/2020	3/2020	4/2020	5/2020	6/2020	7/2020	8/2020	9/2020	10/2020	11/2020	12/2020
Load Forecast (95th% w/no DSM)	(2,521)	(2,563)	(2,289)	(2,195)	(2,945)	(3,504)	(3,991)	(3,331)	(3,218)	(2,298)	(2,401)	(2,796)
Existing DSM (EE)	42	47	40	50	63	78	86	61	75	34	50	50
Load Forecast (95th% w/DSM and EE)	(2,479)	(2,515)	(2,249)	(2,145)	(2,882)	(3,426)	(3,905)	(3,270)	(3,143)	(2,264)	(2,351)	(2,747)
Non-forecasted trended EE	40	46	38	48	61	76	83	59	73	33	48	48
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,439)	(2,470)	(2,210)	(2,097)	(2,821)	(2,961)	(3,432)	(2,874)	(3,071)	(2,231)	(2,303)	(2,699)
Existing Resources												
Total Coal	1,021	1,021	55	55	1,021	1,021	1,021	1,021	1,021	758	758	1,021
Total Gas	716	716	716	416	716	716	716	716	716	416	716	716
Hydro (90th%)—HCC	1,073	1,098	977	1,084	1,152	992	1,000	716	760	880	710	771
Hydro (90th%)—Other	203	207	194	204	305	312	281	207	214	216	189	190
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,276	1,305	1,171	1,288	1,457	1,304	1,281	924	974	1,097	899	961
CSPP (PURPA)	74	76	203	235	375	406	405	396	359	232	204	77
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	39	38	36	32	27	27	23	26	29	30	35	40
Market Purchases	0	0	29	70	0	0	0	0	0	0	0	0
Existing Resource Subtotal	3,127	3,157	2,210	2,097	3,596	3,475	3,446	3,082	3,098	2,533	2,612	2,815
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	688	687	0	0	774	514	13	208	28	302	309	116

Peak-Hour Load and Resource Balance (continued)

	1/2021	2/2021	3/2021	4/2021	5/2021	6/2021	7/2021	8/2021	9/2021	10/2021	11/2021	12/2021
Load Forecast (95th% w/no DSM)	(2,551)	(2,594)	(2,316)	(2,213)	(2,983)	(3,549)	(4,051)	(3,386)	(3,260)	(2,330)	(2,417)	(2,824)
Existing DSM (EE)	57	63	53	55	67	79	85	76	78	46	52	57
Load Forecast (95th% w/DSM and EE)	(2,495)	(2,531)	(2,263)	(2,158)	(2,916)	(3,469)	(3,965)	(3,310)	(3,182)	(2,284)	(2,365)	(2,766)
Non-forecasted trended EE	56	62	52	54	66	78	84	75	77	46	51	56
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,439)	(2,469)	(2,211)	(2,104)	(2,850)	(3,001)	(3,491)	(2,897)	(3,105)	(2,238)	(2,314)	(2,710)
Existing Resources												
Total Coal	966	966	0	0	966	966	966	966	966	703	703	966
Total Gas	716	716	716	416	716	716	716	716	716	416	716	716
Hydro (90th%)—HCC	1,070	1,072	968	1,083	1,149	988	1,000	713	748	879	710	770
Hydro (90th%)—Other	201	205	194	203	304	311	280	206	213	215	188	189
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,271	1,277	1,162	1,286	1,454	1,300	1,280	919	961	1,094	898	959
CSPP (PURPA)	74	76	203	235	375	406	405	396	359	232	204	77
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	39	38	36	32	27	27	23	26	29	30	35	40
Market Purchases	0	0	94	135	0	0	102	0	75	0	0	0
Existing Resource Subtotal	3,067	3,074	2,211	2,104	3,537	3,415	3,491	3,023	3,105	2,476	2,556	2,757
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	628	605	0	0	687	414	0	125	0	237	242	47

Peak-Hour Load and Resource Balance (continued)

	1/2022	2/2022	3/2022	4/2022	5/2022	6/2022	7/2022	8/2022	9/2022	10/2022	11/2022	12/2022
Load Forecast (95th% w/no DSM)	(2,620)	(2,348)	(2,236)	(3,029)	(3,610)	(4,117)	(3,431)	(3,308)	(2,371)	(2,431)	(2,852)	(2,620)
Existing DSM (EE)	70	67	64	77	100	91	83	87	64	48	60	70
Load Forecast (95th% w/DSM and EE)	(2,550)	(2,281)	(2,173)	(2,952)	(3,510)	(4,026)	(3,348)	(3,221)	(2,307)	(2,383)	(2,792)	(2,550)
Non-forecasted trended EE	73	70	66	81	103	94	86	91	67	50	62	73
Existing Demand Response	0	0	0	0	390	390	337	0	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,477)	(2,211)	(2,107)	(2,871)	(3,017)	(3,541)	(2,925)	(3,130)	(2,240)	(2,333)	(2,729)	(2,477)
Existing Resources												
Total Coal	966	0	0	966	966	966	966	966	703	703	966	966
Total Gas	716	716	416	716	716	716	716	716	416	716	716	716
Hydro (90th%)—HCC	1,061	964	1,081	1,147	986	1,000	709	736	879	711	768	1,061
Hydro (90th%)—Other	204	192	203	304	310	279	205	211	214	187	188	204
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,265	1,156	1,283	1,450	1,296	1,279	914	947	1,093	898	956	1,265
CSPP (PURPA)	76	203	235	375	406	405	396	359	232	204	77	76
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	8	7	7	8	8	8	10	9	9	9
Neal Hot Springs Geothermal	24	22	19	14	15	11	13	16	15	20	26	24
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	38	36	32	27	27	23	26	29	30	35	40	38
Market Purchases	0	100	140	0	0	152	0	113	0	0	0	0
Existing Resource Subtotal	3,062	2,211	2,107	3,534	3,412	3,541	3,018	3,130	2,474	2,556	2,755	3,062
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	585	0	0	663	395	0	93	0	234	222	25	585

Peak-Hour Load and Resource Balance (continued)

	1/2023	2/2023	3/2023	4/2023	5/2023	6/2023	7/2023	8/2023	9/2023	10/2023	11/2023	12/2023
Load Forecast (95th% w/no DSM)	(2,617)	(2,647)	(2,374)	(2,271)	(3,080)	(3,664)	(4,201)	(3,485)	(3,346)	(2,405)	(2,477)	(2,903)
Existing DSM (EE)	76	74	71	77	92	112	114	99	85	75	70	82
Load Forecast (95th% w/DSM and EE)	(2,541)	(2,572)	(2,303)	(2,194)	(2,987)	(3,552)	(4,086)	(3,387)	(3,261)	(2,330)	(2,406)	(2,822)
Non-forecasted trended EE	83	82	78	85	101	123	125	108	93	82	77	90
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,457)	(2,491)	(2,225)	(2,109)	(2,886)	(3,039)	(3,571)	(2,941)	(3,167)	(2,248)	(2,329)	(2,732)
Existing Resources												
Total Coal	966	966	0	0	966	966	966	966	966	703	703	966
Total Gas	716	716	716	416	716	716	716	716	716	416	716	716
Hydro (90th%)—HCC	1,063	1,058	961	1,079	1,144	984	1,000	706	724	877	712	766
Hydro (90th%)—Other	199	202	191	202	303	309	278	204	210	211	186	187
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,262	1,260	1,152	1,281	1,447	1,293	1,278	910	934	1,088	898	952
CSPP (PURPA)	74	76	203	235	375	406	405	396	359	232	204	77
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	39	38	36	32	27	27	23	26	29	30	35	40
Market Purchases	0	0	119	144	0	0	183	0	163	0	0	0
Existing Resource Subtotal	3,058	3,057	2,225	2,109	3,531	3,408	3,571	3,014	3,167	2,469	2,556	2,751
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	601	566	0	0	645	369	0	72	0	221	226	19

Peak-Hour Load and Resource Balance (continued)

	1/2024	2/2024	3/2024	4/2024	5/2024	6/2024	7/2024	8/2024	9/2024	10/2024	11/2024	12/2024
Load Forecast (95th% w/no DSM)	(2,658)	(2,679)	(2,413)	(2,283)	(3,120)	(3,721)	(4,268)	(3,534)	(3,412)	(2,428)	(2,514)	(2,931)
Existing DSM (EE)	85	83	85	65	95	121	117	103	107	74	81	79
Load Forecast (95th% w/DSM and EE)	(2,573)	(2,596)	(2,328)	(2,218)	(3,025)	(3,600)	(4,151)	(3,431)	(3,305)	(2,354)	(2,433)	(2,853)
Non-forecasted trended EE	98	95	97	75	109	139	134	118	122	85	93	90
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,475)	(2,500)	(2,231)	(2,143)	(2,917)	(3,071)	(3,626)	(2,976)	(3,183)	(2,269)	(2,340)	(2,762)
Existing Resources												
Total Coal	966	966	0	0	966	966	966	966	966	703	703	966
Total Gas	716	716	716	416	716	716	716	716	716	416	716	716
Hydro (90th%)—HCC	1,060	1,054	958	1,077	1,141	982	1,000	703	716	877	711	767
Hydro (90th%)—Other	198	202	191	202	302	308	277	203	208	209	185	186
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,258	1,256	1,149	1,279	1,443	1,290	1,277	905	924	1,086	896	953
CSPP (PURPA)	74	76	203	235	375	406	405	396	359	232	204	77
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	39	38	36	32	27	27	23	26	29	30	35	40
Market Purchases	0	0	127	181	0	0	239	0	189	0	0	11
Existing Resource Subtotal	3,054	3,053	2,231	2,143	3,527	3,405	3,626	3,009	3,183	2,467	2,554	2,762
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	0	0	0	0	0	0	0	0	0	0	0	0
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	579	552	0	0	610	335	0	33	0	198	214	0

Peak-Hour Load and Resource Balance (continued)

	1/2025	2/2025	3/2025	4/2025	5/2025	6/2025	7/2025	8/2025	9/2025	10/2025	11/2025	12/2025
Load Forecast (95th% w/no DSM)	(2,673)	(2,698)	(2,438)	(2,308)	(3,164)	(3,773)	(4,350)	(3,571)	(3,454)	(2,453)	(2,533)	(2,970)
Existing DSM (EE)	72	81	89	67	101	124	136	94	105	76	76	90
Load Forecast (95th% w/DSM and EE)	(2,601)	(2,617)	(2,350)	(2,240)	(3,062)	(3,648)	(4,215)	(3,476)	(3,349)	(2,377)	(2,456)	(2,880)
Non-forecasted trended EE	86	97	106	81	121	149	163	113	126	92	92	108
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,515)	(2,520)	(2,243)	(2,159)	(2,941)	(3,109)	(3,661)	(3,026)	(3,224)	(2,285)	(2,365)	(2,772)
Existing Resources												
Total Coal	966	966	0	0	966	966	966	966	966	703	703	966
Total Gas	716	716	716	416	716	716	716	716	716	416	716	716
Hydro (90th%)—HCC	1,052	1,050	956	1,075	1,133	981	1,000	699	708	874	713	765
Hydro (90th%)—Other	197	202	190	201	296	302	277	202	207	209	184	185
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,250	1,252	1,146	1,276	1,430	1,283	1,277	901	914	1,082	897	950
CSPP (PURPA)	74	76	203	235	375	406	405	396	359	232	204	76
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	39	38	36	32	27	27	23	26	29	30	35	40
Market Purchases	0	0	142	200	0	0	261	21	240	0	0	24
Existing Resource Subtotal	3,045	3,048	2,243	2,159	3,513	3,398	3,648	3,026	3,224	2,463	2,555	2,772
Monthly Surplus/Deficit	0	0	0	0	0	0	(14)	0	0	0	0	0
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	731	728	200	500	1,072	789	486	500	500	378	390	200

Peak-Hour Load and Resource Balance (continued)

	1/2026	2/2026	3/2026	4/2026	5/2026	6/2026	7/2026	8/2026	9/2026	10/2026	11/2026	12/2026
Load Forecast (95th% w/no DSM)	(2,723)	(2,734)	(2,444)	(2,348)	(3,203)	(3,830)	(4,425)	(3,623)	(3,522)	(2,461)	(2,571)	(2,995)
Existing DSM (EE)	96	97	73	87	103	133	147	103	129	61	93	89
Load Forecast (95th% w/DSM and EE)	(2,627)	(2,637)	(2,370)	(2,261)	(3,099)	(3,697)	(4,278)	(3,521)	(3,393)	(2,399)	(2,479)	(2,906)
Non-forecasted trended EE	121	122	92	109	130	168	185	129	162	77	117	112
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,506)	(2,515)	(2,278)	(2,152)	(2,969)	(3,139)	(3,703)	(3,054)	(3,231)	(2,322)	(2,362)	(2,794)
Existing Resources												
Total Coal	703	703	0	0	703	703	703	703	703	703	703	703
Total Gas	716	716	716	416	716	716	716	716	716	416	716	716
Hydro (90th%)—HCC	1,047	1,047	954	1,073	1,131	979	1,000	696	697	874	713	762
Hydro (90th%)—Other	197	201	190	200	293	299	276	201	205	208	183	184
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,244	1,247	1,143	1,274	1,424	1,278	1,276	897	902	1,082	896	947
CSPP (PURPA)	74	76	202	234	374	405	404	395	358	231	203	76
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	39	38	36	32	27	27	23	26	29	30	35	40
Market Purchases	0	0	181	196	0	10	257	305	302	0	0	301
Existing Resource Subtotal	2,776	2,781	2,278	2,152	3,243	3,139	3,379	3,042	3,010	2,462	2,553	2,782
Monthly Surplus/Deficit	0	0	0	0	0	0	(324)	(13)	(221)	0	0	(12)
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	470	466	200	500	774	500	176	487	279	340	391	188

Peak-Hour Load and Resource Balance (continued)

	1/2027	2/2027	3/2027	4/2027	5/2027	6/2027	7/2027	8/2027	9/2027	10/2027	11/2027	12/2027
Load Forecast (95th% w/no DSM)	(2,748)	(2,762)	(2,480)	(2,368)	(3,239)	(3,863)	(4,476)	(3,681)	(3,558)	(2,498)	(2,588)	(3,026)
Existing DSM (EE)	95	106	89	86	103	119	134	117	121	77	88	94
Load Forecast (95th% w/DSM and EE)	(2,653)	(2,656)	(2,391)	(2,281)	(3,136)	(3,744)	(4,341)	(3,565)	(3,437)	(2,422)	(2,500)	(2,932)
Non-forecasted trended EE	125	139	118	114	136	157	177	154	160	101	116	124
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,528)	(2,517)	(2,273)	(2,167)	(2,999)	(3,197)	(3,774)	(3,074)	(3,277)	(2,321)	(2,384)	(2,809)
Existing Resources												
Total Coal	703	703	0	0	703	703	703	703	703	703	703	703
Total Gas	716	716	716	416	716	716	716	716	716	416	716	716
Hydro (90th%)—HCC	1,044	1,039	949	1,071	1,128	978	1,000	692	687	874	711	761
Hydro (90th%)—Other	196	198	190	200	292	298	275	200	204	207	183	183
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,240	1,237	1,139	1,271	1,421	1,276	1,275	892	890	1,080	894	944
CSPP (PURPA)	73	75	202	234	374	405	404	395	358	231	203	76
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	39	38	36	32	27	27	23	26	29	30	35	40
Market Purchases	0	0	181	214	0	70	254	305	302	0	0	298
Existing Resource Subtotal	2,771	2,770	2,273	2,167	3,240	3,197	3,375	3,037	2,998	2,461	2,551	2,777
Monthly Surplus/Deficit	0	0	0	0	0	0	(399)	(37)	(279)	0	0	(32)
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	444	453	200	500	741	500	101	463	221	340	367	168

Peak-Hour Load and Resource Balance (continued)

	1/2028	2/2028	3/2028	4/2028	5/2028	6/2028	7/2028	8/2028	9/2028	10/2028	11/2028	12/2028
Load Forecast (95th% w/no DSM)	(2,780)	(2,786)	(2,507)	(2,406)	(3,278)	(3,930)	(4,558)	(3,721)	(3,597)	(2,542)	(2,629)	(3,059)
Existing DSM (EE)	100	111	95	103	106	138	153	112	116	98	106	100
Load Forecast (95th% w/DSM and EE)	(2,680)	(2,675)	(2,412)	(2,303)	(3,172)	(3,792)	(4,404)	(3,609)	(3,481)	(2,444)	(2,523)	(2,960)
Non-forecasted trended EE	139	154	132	142	148	192	212	155	161	136	147	138
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,541)	(2,521)	(2,281)	(2,161)	(3,025)	(3,210)	(3,802)	(3,117)	(3,320)	(2,308)	(2,377)	(2,821)
Existing Resources												
Total Coal	703	703	0	0	703	703	703	703	703	703	703	703
Total Gas	716	716	716	416	716	716	716	716	716	416	716	716
Hydro (90th%)—HCC	1,040	1,041	945	1,070	1,126	976	1,000	689	673	872	713	756
Hydro (90th%)—Other	195	197	189	199	292	297	275	199	202	206	181	182
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,236	1,238	1,134	1,269	1,418	1,274	1,275	888	875	1,078	895	938
CSPP (PURPA)	73	75	202	234	374	405	404	395	358	231	203	76
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	34	33	31	27	22	22	18	21	24	25	30	35
Market Purchases	0	0	198	214	0	90	249	305	302	0	0	295
Existing Resource Subtotal	2,762	2,766	2,281	2,161	3,233	3,210	3,364	3,028	2,977	2,453	2,547	2,762
Monthly Surplus/Deficit	0	0	0	0	0	0	(438)	(88)	(343)	0	0	(59)
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	421	445	200	500	708	500	62	412	157	345	370	141

Peak-Hour Load and Resource Balance (continued)

	1/2029	2/2029	3/2029	4/2029	5/2029	6/2029	7/2029	8/2029	9/2029	10/2029	11/2029	12/2029
Load Forecast (95th% w/no DSM)	(2,823)	(2,808)	(2,544)	(2,426)	(3,328)	(3,988)	(4,631)	(3,814)	(3,643)	(2,572)	(2,657)	(3,105)
Existing DSM (EE)	115	111	110	102	118	146	162	159	117	104	111	120
Load Forecast (95th% w/DSM and EE)	(2,708)	(2,697)	(2,434)	(2,325)	(3,210)	(3,842)	(4,469)	(3,655)	(3,527)	(2,468)	(2,546)	(2,985)
Non-forecasted trended EE	167	161	160	148	171	212	235	230	169	151	160	174
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,541)	(2,535)	(2,274)	(2,177)	(3,039)	(3,240)	(3,844)	(3,088)	(3,357)	(2,316)	(2,386)	(2,811)
Existing Resources												
Total Coal	703	703	0	0	703	703	703	703	703	703	703	703
Total Gas	716	716	716	416	716	716	716	716	716	416	716	716
Hydro (90th%)—HCC	1,037	1,037	941	1,068	1,124	975	1,000	686	663	872	712	752
Hydro (90th%)—Other	195	196	189	199	288	292	274	198	200	205	180	180
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,232	1,233	1,130	1,267	1,411	1,267	1,274	884	863	1,077	892	933
CSPP (PURPA)	71	73	200	231	371	402	401	392	355	229	201	73
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	34	33	31	27	22	22	18	21	24	25	30	35
Market Purchases	0	0	197	235	0	130	245	305	302	0	0	293
Existing Resource Subtotal	2,757	2,759	2,274	2,177	3,223	3,240	3,357	3,021	2,962	2,450	2,542	2,753
Monthly Surplus/Deficit	0	0	0	0	0	0	(487)	(66)	(395)	0	0	(58)
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	0	0	0	0	0	0	0
2030 Ice TES	0	0	0	0	0	0	0	0	0	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	500	500	500	500	500	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	416	424	200	500	684	500	13	434	105	334	356	142

Peak-Hour Load and Resource Balance (continued)

	1/2030	2/2030	3/2030	4/2030	5/2030	6/2030	7/2030	8/2030	9/2030	10/2030	11/2030	12/2030
Load Forecast (95th% w/no DSM)	(2,838)	(2,809)	(2,575)	(2,432)	(3,366)	(4,045)	(4,677)	(3,829)	(3,711)	(2,589)	(2,682)	(3,121)
Existing DSM (EE)	106	94	122	88	120	157	146	131	142	99	115	112
Load Forecast (95th% w/DSM and EE)	(2,732)	(2,715)	(2,453)	(2,344)	(3,246)	(3,888)	(4,531)	(3,698)	(3,569)	(2,489)	(2,567)	(3,009)
Non-forecasted trended EE	154	136	177	128	174	228	211	190	206	144	167	162
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,578)	(2,579)	(2,276)	(2,216)	(3,071)	(3,270)	(3,930)	(3,171)	(3,363)	(2,346)	(2,400)	(2,847)
Existing Resources												
Total Coal	703	703	0	0	703	703	703	703	703	703	703	703
Total Gas	716	716	716	416	716	716	716	716	716	416	416	716
Hydro (90th%)—HCC	1,035	1,034	938	1,066	1,121	973	1,000	682	652	873	712	752
Hydro (90th%)—Other	194	194	188	198	288	292	273	197	199	204	180	180
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,229	1,228	1,126	1,264	1,409	1,265	1,273	879	851	1,077	892	931
CSPP (PURPA)	71	73	200	231	371	401	400	390	353	227	199	72
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	34	33	31	27	22	22	18	21	24	25	30	35
Market Purchases	0	0	204	277	0	163	242	305	302	0	161	291
Existing Resource Subtotal	2,754	2,753	2,276	2,216	3,221	3,270	3,352	3,015	2,949	2,448	2,400	2,748
Monthly Surplus/Deficit	0	0	0	0	0	0	(579)	(156)	(414)	0	0	(99)
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	60	60	60	0	0	0	0
2030 Ice TES	0	0	0	0	20	20	20	20	20	0	0	0
2031 Combined Cycle Combustion Turbine	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	200	200	200	500	520	580	580	580	520	200	200	200
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	375	374	200	500	669	580	1	424	106	302	200	101

Peak-Hour Load and Resource Balance (continued)

	1/2031	2/2031	3/2031	4/2031	5/2031	6/2031	7/2031	8/2031	9/2031	10/2031	11/2031	12/2031
Load Forecast (95th% w/no DSM)	(2,852)	(2,842)	(2,592)	(2,448)	(3,407)	(4,091)	(4,764)	(3,855)	(3,744)	(2,614)	(2,691)	(3,150)
Existing DSM (EE)	101	112	123	89	127	160	172	118	135	104	108	119
Load Forecast (95th% w/DSM and EE)	(2,751)	(2,730)	(2,469)	(2,359)	(3,280)	(3,931)	(4,592)	(3,737)	(3,608)	(2,509)	(2,584)	(3,031)
Non-forecasted trended EE	145	162	178	129	184	232	250	170	196	151	156	172
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,606)	(2,569)	(2,292)	(2,230)	(3,095)	(3,309)	(3,952)	(3,230)	(3,412)	(2,358)	(2,428)	(2,859)
Existing Resources												
Total Coal	703	703	0	0	703	703	703	703	703	703	703	703
Total Gas	716	716	716	416	716	716	716	716	716	416	416	716
Hydro (90th%)—HCC	1,034	1,029	935	1,064	1,119	972	1,000	679	641	869	714	749
Hydro (90th%)—Other	193	193	187	197	287	291	272	196	197	202	179	178
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,226	1,222	1,122	1,262	1,406	1,262	1,272	876	839	1,071	893	926
CSPP (PURPA)	66	63	190	221	360	391	390	381	344	218	189	61
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	34	33	31	27	22	22	18	21	24	25	30	35
Market Purchases	0	0	233	304	0	214	238	303	302	0	198	289
Existing Resource Subtotal	2,746	2,737	2,292	2,230	3,207	3,309	3,338	3,000	2,927	2,433	2,428	2,730
Monthly Surplus/Deficit	0	0	0	0	0	0	(615)	(230)	(485)	0	0	(129)
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	60	60	60	0	0	0	0
2030 Ice TES	0	0	0	0	20	20	20	20	20	0	0	0
2031 Combined Cycle Combustion Turbine	300	300	300	300	300	300	300	300	300	300	300	300
New Resource Subtotal	500	500	500	800	820	880	880	880	820	500	500	500
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	640	668	500	800	932	880	265	650	335	575	500	371

Peak-Hour Load and Resource Balance (continued)

	1/2032	2/2032	3/2032	4/2032	5/2032	6/2032	7/2032	8/2032	9/2032	10/2032	11/2032	12/2032
Load Forecast (95th% w/no DSM)	(2,902)	(2,877)	(2,599)	(2,481)	(3,438)	(4,114)	(4,818)	(3,916)	(3,798)	(2,625)	(2,715)	(3,172)
Existing DSM (EE)	130	132	113	106	125	141	167	140	151	97	114	119
Load Forecast (95th% w/DSM and EE)	(2,772)	(2,745)	(2,486)	(2,375)	(3,313)	(3,972)	(4,651)	(3,776)	(3,647)	(2,529)	(2,601)	(3,054)
Non-forecasted trended EE	188	191	164	153	181	205	241	203	218	140	165	171
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,584)	(2,554)	(2,322)	(2,223)	(3,132)	(3,377)	(4,020)	(3,236)	(3,429)	(2,389)	(2,437)	(2,882)
Existing Resources												
Total Coal	703	703	0	0	703	703	703	703	703	703	703	703
Total Gas	716	716	716	416	716	716	716	716	716	416	416	716
Hydro (90th%)—HCC	1,032	1,025	932	1,063	1,118	971	1,000	676	630	869	714	746
Hydro (90th%)—Other	192	192	187	196	285	289	272	195	196	201	178	176
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,224	1,218	1,119	1,259	1,403	1,259	1,272	871	826	1,070	892	922
CSPP (PURPA)	59	60	187	219	359	390	389	380	343	216	188	61
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	34	33	31	27	22	22	18	21	24	25	30	35
Market Purchases	0	0	269	301	0	287	234	299	302	0	208	287
Existing Resource Subtotal	2,736	2,730	2,322	2,223	3,203	3,377	3,331	2,990	2,914	2,431	2,437	2,724
Monthly Surplus/Deficit	0	0	0	0	0	0	(689)	(245)	(515)	0	0	(158)
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	60	60	60	0	0	0	0
2030 Ice TES	0	0	0	0	20	20	20	20	20	0	0	0
2031 Combined Cycle Combustion Turbine	300	300	300	300	300	300	300	300	300	300	300	300
New Resource Subtotal	500	500	500	800	820	880	880	880	820	500	500	500
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	652	677	500	800	890	880	191	635	305	542	500	342

Peak-Hour Load and Resource Balance (continued)

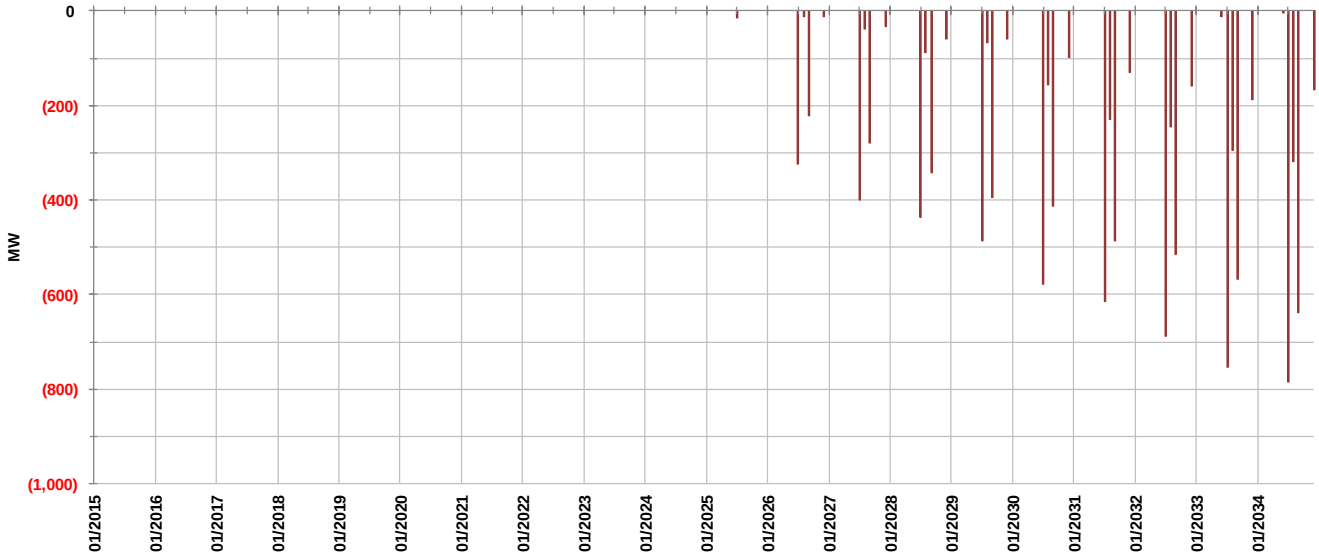
	1/2033	2/2033	3/2033	4/2033	5/2033	6/2033	7/2033	8/2033	9/2033	10/2033	11/2033	12/2033
Load Forecast (95th% w/no DSM)	(2,920)	(2,903)	(2,622)	(2,502)	(3,478)	(4,163)	(4,886)	(3,962)	(3,845)	(2,650)	(2,739)	(3,200)
Existing DSM (EE)	126	141	118	109	129	146	173	145	157	101	119	123
Load Forecast (95th% w/DSM and EE)	(2,794)	(2,763)	(2,504)	(2,393)	(3,348)	(4,017)	(4,713)	(3,817)	(3,688)	(2,549)	(2,620)	(3,077)
Non-forecasted trended EE	183	204	171	158	187	212	251	210	228	146	172	179
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,611)	(2,559)	(2,332)	(2,235)	(3,161)	(3,415)	(4,071)	(3,270)	(3,461)	(2,404)	(2,448)	(2,899)
Existing Resources												
Total Coal	703	703	0	0	703	703	703	703	703	703	703	703
Total Gas	716	716	716	416	716	716	716	716	716	416	416	716
Hydro (90th%)—HCC	1,030	1,004	929	1,061	1,116	969	1,000	673	620	870	712	745
Hydro (90th%)—Other	191	191	186	196	282	285	271	194	195	200	177	175
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,221	1,195	1,115	1,257	1,398	1,254	1,271	867	814	1,070	889	921
CSPP (PURPA)	50	52	178	210	350	381	380	371	334	208	179	52
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	34	33	31	27	22	22	18	21	24	25	30	35
Market Purchases	0	0	292	324	0	328	230	296	302	0	231	285
Existing Resource Subtotal	2,724	2,699	2,332	2,235	3,189	3,404	3,318	2,974	2,893	2,422	2,448	2,712
Monthly Surplus/Deficit	0	0	0	0	0	(11)	(754)	(296)	(568)	0	0	(187)
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	60	60	60	0	0	0	0
2030 Ice TES	0	0	0	0	20	20	20	20	20	0	0	0
2031 Combined Cycle Combustion Turbine	300	300	300	300	300	300	300	300	300	300	300	300
New Resource Subtotal	500	500	500	800	820	880	880	880	820	500	500	500
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	613	640	500	800	848	869	126	584	252	518	500	313

Peak-Hour Load and Resource Balance (continued)

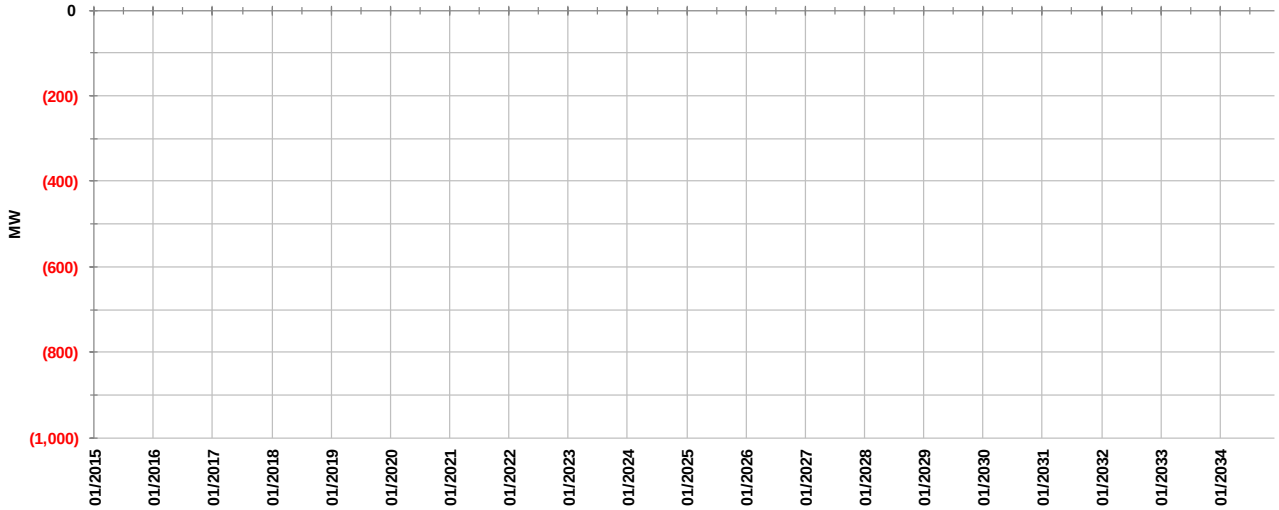
	1/2034	2/2034	3/2034	4/2034	5/2034	6/2034	7/2034	8/2034	9/2034	10/2034	11/2034	12/2034
Load Forecast (95th% w/no DSM)	(2,955)	(2,917)	(2,652)	(2,539)	(3,531)	(4,241)	(4,966)	(4,017)	(3,870)	(2,698)	(2,768)	(3,256)
Existing DSM (EE)	141	139	132	130	149	181	193	160	142	129	131	156
Load Forecast (95th% w/DSM and EE)	(2,815)	(2,778)	(2,520)	(2,409)	(3,382)	(4,060)	(4,773)	(3,857)	(3,728)	(2,569)	(2,638)	(3,100)
Non-forecasted trended EE	204	202	192	189	217	264	280	232	206	188	190	226
Existing Demand Response	0	0	0	0	0	390	390	337	0	0	0	0
Peak-Hour Forecast w/DSM (EE)	(2,610)	(2,576)	(2,328)	(2,220)	(3,166)	(3,406)	(4,103)	(3,287)	(3,522)	(2,381)	(2,448)	(2,873)
Existing Resources												
Total Coal	703	703	0	0	703	703	703	703	703	703	703	703
Total Gas	716	716	716	416	716	716	716	716	716	416	416	716
Hydro (90th%)—HCC	1,028	992	926	1,059	1,114	968	1,000	669	612	868	712	743
Hydro (90th%)—Other	190	190	186	195	278	283	270	193	194	200	176	174
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,219	1,181	1,112	1,254	1,392	1,251	1,270	862	806	1,068	888	917
CSPP (PURPA)	50	52	178	210	350	381	380	371	334	208	179	52
PPAs												
Elkhorn Valley Wind	0	0	0	0	0	0	0	0	0	0	0	0
Raft River Geothermal	9	9	9	8	7	7	8	8	8	10	9	9
Neal Hot Springs Geothermal	25	24	22	19	14	15	11	13	16	15	20	26
Clatskanie Exchange–Take	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange– Return	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	34	33	31	27	22	22	18	21	24	25	30	35
Market Purchases	0	0	291	313	0	328	230	296	302	0	232	285
Existing Resource Subtotal	2,721	2,685	2,328	2,220	3,183	3,401	3,317	2,970	2,884	2,420	2,448	2,708
Monthly Surplus/Deficit	0	0	0	0	0	(5)	(786)	(318)	(638)	0	0	(165)
2015 IRP Resources												
2025 Boardman to Hemingway Transmission	200	200	200	500	500	500	500	500	500	200	200	200
2030 New DR	0	0	0	0	0	60	60	60	0	0	0	0
2030 Ice TES	0	0	0	0	20	20	20	20	20	0	0	0
2031 Combined Cycle Combustion Turbine	300	300	300	300	300	300	300	300	300	300	300	300
New Resource Subtotal	500	500	500	800	820	880	880	880	820	500	500	500
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	611	609	500	800	837	875	94	562	182	538	500	335

Peak-Hour Surplus/Deficit Charts

Peak-hour monthly deficits with existing DSM and existing resources



Peak-hour monthly deficits with existing DSM, existing resources, IRP DSM, and IRP resources



DEMAND-SIDE RESOURCE DATA

Cost Effectiveness

Idaho Power considers cost-effectiveness to be the primary screening tool prior to demand-side management (DSM) program implementation. Idaho Power uses the total resource cost (TRC) test and the utility cost (UC) test to develop benefit cost (B/C) ratios to determine the cost-effectiveness of DSM programs for inclusion in resource planning. The two tests insure that the program benefits will exceed costs from both the perspective of Idaho Power (UC) and its customers (TRC). For ongoing programs, tests are also run to look at cost-effectiveness from the point of view of the program participant. Each energy efficiency and demand response program and individual program measures are reviewed annually as part of preparation of an annual report that is submitted to both the Idaho and Oregon public utility commissions. More information on Idaho Power's programs and cost-effectiveness are included in the *Demand-Side Management 2012 Annual Report* and its *Supplement 1: Cost-Effectiveness,* (idahopower.com/EnergyEfficiency/reports.cfm).

Incorporated into the cost-effectiveness analysis are inputs from various sources that represent the most current and reliable information available. Measure savings, measure life, and participant cost assumptions for prescriptive programs are usually sourced from the Regional Technical Forum (RTF), which is the regional advisory group and technical arm of the Northwest Power and Conservation Council (NPCC). For custom and non-prescriptive programs, annual energy savings can be derived from program evaluations, engineering estimates, or regionally deemed values. Participant costs for non-prescriptive programs are often actual costs from customer-submitted information. Other inputs used in the cost-effectiveness models are obtained from the IRP process, including the financial assumptions along with the forecasted value of DSM alternative costs.

Idaho Power determines cost-effectiveness on both a program basis and also on a measure-by-measure basis. In all cases, when cost-effectiveness is calculated for one measure or for an entire program, to be considered cost-effective, the B/C ratios must be greater than one for both the TRC and UC tests.

For the 2015 IRP, non-energy related benefits (NEB) were included in the cost-effectiveness analysis of the program forecasts. NEB include savings from the customer's perspective, including water savings, deferred maintenance and operational costs, health and safety benefits, avoided supplemental fuels, and other quantifiable benefits apart from avoided energy production. NEB were applied to the energy efficiency forecast at the sector level based on cost-effectiveness analysis of the 2014 portfolio of programs. For a complete list of NEB and sources that Idaho Power currently uses for its program cost-effectiveness, see *Demand-Side Management 2014 Annual Report* and its *Supplement 1: Cost-Effectiveness,* (idahopower.com/EnergyEfficiency/reports.cfm).

The cost-effective analysis methods used at Idaho Power are consistent with published methods and standard practices. Idaho Power relies on the *Electric Power Research Institute End Use Technical Assessment Guide* (TAG) *Understanding Cost-Effectiveness of Energy Efficiency Programs,* and the *California Standard Practice Manual* for the cost-effectiveness methodology. As defined in the TAG and *California Standard Practice Manual*, the TRC and UC tests are most similar to supply-side cost analysis and provide a useful basis to compare demand-side and supply-side resources.

Resource Development and Evaluation

When developing energy efficiency programs, Idaho Power uses actual data and experiences from other companies in the region, or throughout the country, where applicable, to help identify specific program

parameters. The regional program review is typically accomplished through discussions with other utilities' program managers and research staff. Other program development resources include; E Source, Edison Electrical Institute (EEI), Consortium for Energy Efficiency (CEE), American Council for an Energy Efficient Economy (ACEEE), Advanced Load Control Alliance (ALCA). For other assumptions, including estimated cost, savings, Idaho Power relies on sources, such as the NPCC, the RTF, NEEA, the Database for Energy Efficiency Resources (DEER), third-party consultants, and other regional utilities.

Sometimes Idaho Power launches pilot programs or limited-scale programs; to evaluate estimates or assumptions in the cost-effectiveness model. Pilot programs are designed to measure actual program experiences, including program expenses, savings, and participation. Following implementation of a program, the cost-effectiveness models are reviewed as data from actual program activity becomes available. The program design may be re-examined after program implementation.

All programs are included in an ongoing evaluation schedule where a third-party consultant verifies the claimed savings from the program. Programs are also evaluated to review the program processes to review the effectiveness of the program delivery. If an evaluation determines that savings are less than claimed or that there is potential for improvement in delivery of the program then changes can be made based on the recommendations. Recent evaluations from the 2014 program year can be reviewed in the *Demand-Side Management 2014 Annual Report* and its *Supplement 2: Evaluations,* (idahopower.com/EnergyEfficiency/reports.cfm).

Planning Assumptions and Alternate Costs

The financial assumptions used in the analysis for the 2015 IRP are consistent with the financial assumptions made for supply-side resources, including the discount rate and cost escalation rates. Table DSM-1 lists the financial assumptions The IRP is also the source of the DSM alternative costs, which is the basis for estimating the value of energy savings and demand reduction resulting from the DSM programs. The DSM alternative costs vary by season and time-of-day. The DSM alternative energy costs are based on either projected fuel costs of a natural gas peaking unit for peak summer hours or forward marginal prices as determined by the AURORAxmp® Electric Market Model. The avoided capacity resource for peak summer hours and for demand response programs is based on a 170 MW natural gas-fired, simple-cycle combustion turbine (SCCT).

The prices of avoided energy throughout the 20-year planning period were simulated using 2015 IRP Portfolio 6b. Portfolio 6b was run assuming 111d sensitivity #5 within the AURORA model. The AURORA model is a production cost tool that simulates hourly economic dispatch and commitment of supply-side, demand-side, and transmission resources. Idaho Power's setup of the AURORA model forecasts electric market prices throughout the Western Electricity Coordinating Council (WECC) region. AURORA also forecasts marginal electricity costs for Idaho Power. Marginal electricity costs are set by the highest variable cost resource that is dispatched in any given forecasted hour. Variable costs include variable O&M and variable fuel costs. Idaho Power modeled hourly, marginal electricity costs for the years 2015 through 2034 to estimate the potential system benefit of avoiding production of the next unit of energy. An initial run of marginal costs are run during the preliminary analysis phase of the IRP process. The preliminary runs will combine updated planning assumptions including load and natural gas price forecasts run against the current preferred resource portfolio from the previous IRP. After the selection of the preferred portfolio which for the 2015 IRP is portfolio 6b, a final run of marginal prices are run which become the avoided energy prices for DSM energy valuation until the next IRP cycle.

The forward prices are placed into five homogenous pricing categories for the convenience of cost-effectiveness calculation the categories follow the pattern of heavy and light load pricing throughout each year of the planning period. The resulting categories include the following:

- Summer On-Peak (SONP)—Average of Idaho Power variable energy and operating costs of a 170 MW SCCT, which is the marginal resource for peak hour load deficits during summertime heavy load hours
- Summer Mid-Peak (SMP)—Average of heavy load prices from June to August (excluding the SONP hours)
- Summer Off-Peak (SOFP)—Average of light load prices from June to August
- Non-Summer Mid-Peak (NSMP)—Average of heavy load prices in January through May and September through December
- Non-Summer Off-Peak (NSOFP)—Average of light load prices in January through May and September through December

The SONP is treated differently than the other four pricing periods when valuing energy efficiency. The estimated levelized capacity cost of a new SCCT is approximately $119 per kW over a 30-year period. The avoided capacity value is spread across the annual SONP hours to estimate the value of energy efficiency savings occurring during the hours. The total SONP hours vary between 512 to 528 hours depending on the year. When the levelized capacity cost of a new SCCT ($119/kW) is multiplied by the Effective Load Carry Capacity (ELCC) of 89 percent which is the estimated percent of top 100 peak load hours that demand response can cover, the annual avoided capacity cost is $106/kW. For demand response or direct load control DSM programs $106 per kW becomes the cost threshold for program cost-effectiveness on an annual per kW basis.

Annual benefits for demand response are also established as part of the IRP process once the value of the 170 MW SCCT is determined. The method for determining cost-effectiveness for demand response programs was updated in 2014 as part of a series of public workshop supporting IPUC Case No. IP-E-13-14 resulting in orders from both the IPUPC (No. 32980) and Oregon (No.13-482). The orders established that through the IRP process IPC will establish an annual operating cost ceiling tied to the levelized annual benefit of a 170-MW SCCT. The updated established annual value for the 2015 IRP is $18.5 million which is an increase from 16.7 million from the 2013 IRP. While the intent of the benefit calculation provides guidance for annual cost limit to operating demand response in years with no anticipated peak deficits, actual 2014 operating costs of demand response programs were considerable less at 10.6 million.

Forecast and Cost-Effectiveness Data

Table DSM-1 lists the financial assumptions used for the cost-effectiveness analysis and new program screening.

Table DSM-2 shows the results of averaging forward marginal energy prices over the 20-year planning period that were determined as a result of the IRP planning process and selection of the preferred portfolio. The alternate cost prices for energy efficiency measures that have a life longer than the 20-year planning horizon, which is typical for weatherization and building shell measures, are escalated at 2.2 percent annually beyond the planning period.

Tables DSM-3 and DSM-4 show the distribution of the three summer and two non-summer pricing periods across the hours and days of the week and for holidays.

Tables DSM-5 and DSM-6 lists the 20-year cumulative forecasted impact of average energy (aMW) and on-peak reduction (MW) by customer class.

Table DSM-7 details the 20-year estimated utility or program administrator costs to support the achievable potential forecast by customer class.

Table DSM-8 details the 20-year estimated TRC that accounts for both program administration costs and incremental costs to acquire efficient measures and equipments by customers listed by customer class.

Table DSM-9 outlines the 20-year flow of total benefits attributed to energy efficiency programs including NEB associated with the forecast.

Table DSM-10 summarizes the cost-effectiveness analysis for energy efficiency programs through the 20-year IRP planning period.

Table DSM-1. IRP financial assumptions

DSM Analysis Assumptions	
Avoided 30-Year Levelized Capacity Costs	
SCCT	$119/kW
Financial Assumptions	
Weighted average cost of capital (2014 year ending after tax)	6.74%
Financial escalation factor	2.20%
Transmission Losses	
Non-summer secondary losses	9.60%
Summer peak loss	9.70%

Table DSM-2. DSM alternate costs by pricing period

Year	Summer On-Peak* (SONP)	Summer Mid-Peak (SMP)	Summer Off-Peak (SOFP)	Non-Summer Mid-Peak (NSMP)	Non-Summer Off-Peak (NSOFP)
2015	$62.94	$44.84	$39.58	$31.67	$25.98
2016	$59.05	$40.44	$31.86	$33.75	$27.20
2017	$59.90	$39.64	$29.55	$35.44	$28.21
2018	$65.19	$43.78	$31.37	$38.82	$30.39
2019	$69.96	$43.83	$32.20	$38.74	$30.94
2020	$72.48	$42.68	$36.40	$38.06	$30.90
2021	$75.10	$47.16	$39.39	$41.11	$33.13
2022	$77.01	$49.12	$41.30	$43.02	$34.72
2023	$80.16	$51.53	$46.42	$44.43	$36.23
2024	$82.91	$53.18	$46.25	$46.27	$38.89
2025	$85.45	$48.50	$40.63	$47.50	$40.33
2026	$85.22	$51.66	$42.84	$48.75	$42.18
2027	$86.54	$53.57	$44.94	$49.64	$43.66
2028	$89.52	$55.95	$46.56	$51.45	$45.72
2029	$93.32	$59.08	$49.66	$53.69	$48.05
2030	$98.68	$64.01	$53.60	$56.72	$51.40
2031	$103.53	$64.37	$56.15	$58.55	$53.88
2032	$106.22	$66.04	$58.74	$61.52	$56.57
2033	$110.98	$71.21	$63.23	$64.96	$60.09
2034	$119.66	$78.44	$67.91	$68.39	$62.98

* Estimated average annual variable operations and management costs of a 170 MW capacity SCCT.

Table DSM-3. DSM alternate cost summer pricing periods (June 1–August 31)

Hour	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Holiday
1	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
2	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
3	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
4	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
5	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
6	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
7	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
8	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
9	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
10	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
11	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
12	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
13	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
14	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
15	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
16	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
17	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
18	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
19	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
20	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
21	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
22	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
23	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
24	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP

Table DSM-4. DSM alternate cost non-summer pricing periods (September 1–May 31)

Hour	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Holiday
1	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
2	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
3	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
4	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
5	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
6	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
7	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
8	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
9	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
10	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
11	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
12	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
13	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
14	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
15	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
16	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
17	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
18	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
19	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
20	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
21	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
22	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
23	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
24	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP

Table DSM-5. Cumulative existing energy efficiency forecast 2015–2034
(aMW w/transmission losses)

Year	Residential	Commercial/Industrial/ Special Contracts	Irrigation	Total
2015	3	8	1	12
2016	8	17	3	27
2017	14	26	4	45
2018	21	35	9	65
2019	28	46	11	84
2020	33	55	13	101
2021	38	64	15	117
2022	43	74	17	134
2023	49	83	19	152
2024	55	93	22	169
2025	61	102	22	185
2026	67	111	22	200
2027	73	120	22	215
2028	79	129	22	231
2029	85	138	23	246
2030	91	144	23	257
2031	96	150	23	269
2032	101	156	23	280
2033	106	161	23	290
2034	111	167	23	301

Table DSM-6. Cumulative Energy Efficiency On-Peak Forecast 2015–2034

Year	Residential	Commercial/Industrial/ Special Contracts	Irrigation	Total
2015	3	13	4	21
2016	9	18	8	35
2017	16	36	13	65
2018	22	56	25	103
2019	17	75	34	126
2020	41	87	41	168
2021	54	66	49	169
2022	55	79	51	185
2023	66	114	60	240
2024	34	149	69	252
2025	67	160	71	299
2026	93	170	70	333
2027	118	121	73	311
2028	107	187	71	366
2029	120	209	68	397
2030	58	227	72	357
2031	114	233	75	422
2032	176	156	75	408
2033	187	162	76	425
2034	175	226	72	473

Table DSM-7. Energy Efficiency Total Utility (Program Administrator) Costs 2015–2034 ($000s)

Year	Residential	Commercial/Industrial/ Special Contracts	Irrigation	Total
2015	$7,055	$9,469	$1,467	$17,991
2016	$9,976	$10,289	$1,509	$21,773
2017	$12,738	$11,386	$1,529	$25,653
2018	$13,667	$11,539	$4,878	$30,085
2019	$14,999	$13,288	$2,501	$30,787
2020	$13,339	$12,356	$2,527	$28,221
2021	$14,535	$12,302	$2,576	$29,413
2022	$16,012	$12,806	$2,700	$31,518
2023	$17,772	$13,611	$2,813	$34,197
2024	$18,220	$13,886	$2,902	$35,009
2025	$18,358	$12,850	$229	$31,438
2026	$18,771	$13,405	$232	$32,408
2027	$19,463	$13,776	$267	$33,506
2028	$20,865	$14,197	$260	$35,322
2029	$20,510	$14,352	$252	$35,114
2030	$18,994	$9,813	$228	$29,035
2031	$18,935	$9,602	$266	$28,803
2032	$18,928	$9,742	$264	$28,934
2033	$18,862	$9,550	$272	$28,684
2034	$18,719	$10,081	$197	$28,998
20-Year NPV	**$165,579**	**$128,817**	**$18,449**	**$312,845**

Table DSM-8. Energy Efficiency Total Resource Costs 2015–2034 ($000s)

Year	Residential	Commercial/Industrial/ Special Contracts	Irrigation	Total
2015	$16,326	$18,669	$11,067	$46,061
2016	$29,583	$20,286	$11,385	$61,254
2017	$38,737	$22,450	$11,533	$72,720
2018	$42,651	$22,751	$36,805	$102,207
2019	$42,679	$26,199	$18,868	$87,746
2020	$30,400	$24,361	$19,067	$73,829
2021	$34,094	$24,255	$19,435	$77,784
2022	$38,590	$25,249	$20,369	$84,208
2023	$42,024	$26,837	$21,228	$90,089
2024	$42,358	$27,379	$21,898	$91,635
2025	$47,611	$25,336	$1,731	$74,678
2026	$46,892	$26,430	$1,752	$75,074
2027	$48,215	$27,161	$2,016	$77,391
2028	$52,314	$27,992	$1,958	$82,264
2029	$50,857	$28,297	$1,900	$81,054
2030	$46,970	$19,348	$1,722	$68,040
2031	$47,774	$18,931	$2,009	$68,714
2032	$46,959	$19,208	$1,994	$68,161
2033	$47,981	$18,830	$2,051	$68,862
2034	$44,098	$19,877	$1,486	$65,461
20-Year NPV	**$425,360**	**$253,982**	**$139,206**	**$818,548**

Table DSM-9. Total Energy Efficiency Benefits 2015–2034 ($000s)

Year	Residential	Commercial/Industrial/ Special Contracts	Irrigation	Total
2015	$21,699	$36,952	$14,660	$73,310
2016	$38,766	$38,720	$14,574	$92,061
2017	$49,147	$41,059	$14,219	$104,426
2018	$52,146	$52,256	$43,698	$148,101
2019	$49,827	$47,230	$21,487	$118,544
2020	$33,160	$42,650	$20,917	$96,727
2021	$35,039	$40,544	$20,306	$95,888
2022	$37,416	$40,278	$20,249	$97,943
2023	$38,390	$40,571	$20,011	$98,971
2024	$36,462	$39,329	$19,573	$95,364
2025	$38,695	$27,735	$1,465	$67,895
2026	$35,732	$27,415	$1,403	$64,550
2027	$34,540	$26,725	$1,526	$62,790
2028	$35,273	$26,015	$1,401	$62,690
2029	$32,236	$24,768	$1,283	$58,287
2030	$27,963	$15,185	$1,097	$44,244
2031	$26,665	$13,946	$1,204	$41,814
2032	$24,523	$13,256	$1,121	$38,901
2033	$23,395	$12,098	$1,081	$36,574
2034	$20,077	$11,902	$734	$32,712
20-Year NPV	**$691,151**	**$618,633**	**$222,009**	**$1,531,793**

Table DSM-10. Total energy efficiency cost-effectiveness summary

	2034 Load Reduction (aMW)	Utility Costs ($000s) (20-Year NPV)	Resource Costs ($000s) (20-Year NPV)	Total Benefits ($000s) (20-Year NPV)	TRC: Benefit/ Cost Ratio	TRC Levelized Costs (cents/kWh)
Residential	111	$165,579	$425,360	$691,151	1.6	9.8
Industrial/Commercial/ Special Contract	167	$128,817	$253,982	$618,633	2.4	3.3
Irrigation	23	$18,449	$139,206	$222,009	1.6	10.3
Total	**301**	**$312,845**	**$818,548**	**$1,531,793**	**1.9**	**6.1**

SUPPLY-SIDE RESOURCE DATA

Key Financial and Forecast Assumptions

Financing Cap Structure and Cost	
Composition	
Debt	50.04%
Preferred	0.00%
Common	49.96%
Total	**100.00%**
Cost	
Debt	5.73%
Preferred	0.00%
Common	10.00%
Average Weighted Cost	7.86%

Financial Assumptions and Factors	
Plant operating (book) life	Expected Life of the Asset
Discount rate (weighted average cost of capital[1])	6.74%
Composite tax rate	39.10%
Deferred rate	35.00%
General O&M escalation rate	2.20%
Annual property tax rate (% of investment)	0.29%
Property tax escalation rate	3.00%
Annual insurance premiums (% of investment)	0.31%
Insurance escalation rate	2.00%
AFUDC rate (annual)	7.75%

[1] Incorporates tax effects.

Emission Intensity Rate (lbs per MWh by technology)	
	CO_2
Small aeroderivative SCCT	1,115
Large aeroderivative SCCT	1,047
Large frame SCCT	1,413
CCCT 1x1	809
CCCT 2x1	809
Combined heat and power (CHP)	1,115
Distributed generation–gas fired	1,115
Pulverized coal	1,901
IGCC	2,279
IGCC w/carbon sequestration	421

Fuel Forecast Base Case (Nominal, $ per MMBtu)			
Year	**Natural Gas**	**Generic Coal**	**Nuclear**
2015	$5.10	$1.47	$0.51
2016	$4.70	$1.52	$0.52
2017	$4.76	$1.55	$0.53
2018	$5.25	$1.58	$0.54
2019	$5.69	$1.61	$0.56
2020	$5.91	$1.64	$0.57
2021	$6.14	$1.69	$0.58
2022	$6.30	$1.74	$0.59
2023	$6.58	$1.78	$0.61
2024	$6.82	$1.83	$0.62
2025	$7.04	$1.87	$0.63
2026	$6.99	$1.91	$0.65
2027	$7.09	$1.98	$0.66
2028	$7.35	$2.00	$0.68
2029	$7.69	$2.07	$0.69
2030	$8.18	$2.12	$0.71
2031	$8.62	$2.16	$0.72
2032	$8.85	$2.21	$0.74
2033	$9.28	$2.27	$0.75
2034	$10.09	$2.32	$0.77
2035	$10.15	$2.34	$0.79
2036	$10.21	$2.35	$0.81
2037	$10.27	$2.37	$0.82
2038	$10.33	$2.38	$0.83
2039	$10.39	$2.39	$0.83
2040	$10.46	$2.41	$0.84
2041	$10.52	$2.42	$0.84
2042	$10.58	$2.44	$0.85
2043	$10.65	$2.45	$0.85
2044	$10.71	$2.47	$0.86

Cost Inputs and Operating Assumptions

(All costs in 2015 dollars)

Supply-Side Resources	Plant Capacity (MW)	Plant Capital ($/kW)[1,3]	Transmission Capital $/kW	Total Capital $/kW	Total Investment $/kW[2]	Fixed O&M $/kW[3]	Variable O&M $/kW	Other $/MWh	Heat Rate Btu/kWh	Economic Life
Advanced Nuclear (250 MW)	1,100	4,350	441	$4,791	$7,266	95	0	0	10,450	40
Battery Storage (6 MW)	6	3,000	0	$3,000	$3,059	28	0	0	NA	10
Biomass Direct—Woody Residue (35 MW)	35	2,622	357	$2,979	$3,189	95	15	0	14,500	30
Biomass Indirect—Anaerobic Digester (3 MW)	3	4,761	133	$4,894	$5,239	43	14	0	10,250	25
Boardman to Hemingway (350 MW)	350	0	703	$703	$703	0	0	0	NA	55
Canal Drop Hydro (1.28 MW)	1	3,600	70	$3,670	$4,371	20	0	0	NA	75
CCCT (1x1) F Class with Duct Firing (270 MW)	270	1,145	122	$1,267	$1,484	8	2	0	6,714	30
CCCT (2x1) F Class (580 MW)	580	899	101	$1,000	$1,172	6	4	0	6,700	30
CHP (45 MW)	45	2,123	57	$2,180	$2,334	47	5	0	6,060	40
IGCC (580 MW)	580	3,257	745	$4,002	$4,773	62	7	0	8,800	35
IGCC with Carbon Capture (580 MW)	580	6,390	744	$7,134	$8,510	73	9	0	10,520	35
Geothermal (30 MW)	30	4,021	850	$4,871	$5,402	0	30	0	NA	25
ICE Thermal Storage (10 MW)	10	1,500	0	$1,500	$1,529	30	0	0	NA	20
Pumped Storage (150 MW)	150	5,000	1,095	$6,095	$7,259	20	0	0	NA	50
Reciprocating Gas Engine (18.8 MW)	19	500	73	$573	$610	2	4	0	7,329	40
SCCT—Aeroderivative (47 MW)	47	1,000	46	$1,046	$1,114	25	8	0	9,000	35
SCCT—Frame F Class (170 MW)	170	800	194	$994	$1,059	5	5	0	10,300	35
Shoshone Falls Upgrade (49.5 MW)	50	2,255	269	$2,524	$2,825	2	0	0	NA	75
Small Modular Nuclear (250 MW)	600	5,000	520	$5,520	$8,371	0	23	0	11,493	40
Solar Power Tower (110 MW)	110	6,250	330	$6,580	$7,710	82	3	6	NA	20
Solar PV—Distr Residential Fixed S (10 MW)	10	3,500	0	$3,500	$3,639	25	0	6	NA	20
Solar PV—Distr C&I Fixed S (10 MW)	10	2,500	0	$2,500	$2,599	13	0	6	NA	20
Solar PV—Distr C&I Fixed SW (10 MW)	10	2,500	0	$2,500	$2,599	13	0	6	NA	20
Solar PV—Utility Scale Fixed S (10 MW)	10	1,500	305	$1,805	$1,877	13	0	6	NA	20
Solar PV—Utility Scale Fixed SW (10 MW)	10	1,500	305	$1,805	$1,877	13	0	6	NA	20
Solar PV—Utility Scale 1-Axis Tracking (10 MW)	10	1,750	305	$2,055	$2,136	20	0	6	NA	20
Solar PV—Utility Scale 2-Axis Tracking (10 MW)	10	1,860	305	$2,165	$2,251	24	0	6	NA	20
TurboPhase (23.6 MW)	24	400	0	$400	$403	0	4	0	7,824	35
Wind (100 MW)	100	1,800	330	$2,130	$2,276	40	0	15	NA	25

[1] Plant costs include engineering development costs, generating and ancillary equipment purchase, and installation costs, as well as balance of plant construction.
[2] Total Investment includes capital costs and AFUDC.
[3] Fixed O&M excludes property taxes and insurance (separately calculated within the levelized resource cost analysis)

Transmission Cost Assumptions

Cost Assumptions by Supply-Side Resource Type

Capacity (MW Rating)	Overnight Transmission Capital Cost/kW[1]	Cost Assumptions Notes	Local Interconnection Assumptions	Backbone Transmission Assumptions
Battery Storage				
6	$0	Assume location in or near existing substation.	No transmission upgrades required.	No backbone upgrades required.
Biomass Direct—Woody Residue				
35	$357	Assume a 20-mile, 138-kV line to existing Idaho Power 138-kV substation. Add 3 new 138-kV terminals. Assume $250k in communications upgrades.	Assume a 20-mile, 138-kV line interconnection to existing Idaho Power 138-kV substation. Add 3 new 138-kV terminals. Assume $250k in communications upgrades.	No backbone upgrades required.
Biomass Indirect—Anaerobic Digester				
3	$133	Assume distribution feeder location with no backbone transmission upgrades required.	Assume $300k of distribution feeder upgrades and $100k in substation upgrades.	No backbone upgrades required.
Coal—Integrated Gasification Combined Cycle (IGCC)				
580	$745	Assume resource is located close to future 500-kV Aeolus substation. Pro-rated share of 3000 MW Gateway West project, with estimated toal cost of $2.19 billion.	Assume resource is located close to future 500-kV Aeolus substation. Assume 2 new terminals at 500-kV substation.	Pro-rata share of Gateway.
Coal—IGCC with Carbon Capture and Sequestration				
600	$744	Assume resource is located close to future 500-kV Aeolus substation. Pro-rated share of 3000 MW Gateway West project, with estimated toal cost of $2.19 billion .	Assume resource is located close to future 500-kV Aeolus substation. Assume 2 new terminals at 500-kV substation.	Pro-rata share of Gateway.
Geothermal (binary-cycle)—Idaho				
30	$850	Assume Raft River area. Requires 45-mile, 138-kV line to existing Minidoka substation. Assume capacity fits on existing backbone.	New 45-mile, 138-kV line to Minidoka substation with new 138-kV substation line terminal bay.	No backbone upgrades required.
Hydro—Canal Drop (Seasonal)				
10	$70	Assume 46-kV sub-transmission or local feeder interconnection. Feeder rebuild or 46-kV upgrade would likely be required.	Assume 4 miles of distribution rebuild at $150k per mile plus $100k in substation upgrades.	No backbone upgrades required.
Hydro—Shoshone Falls Expansion				
50	$269	Line and station modifications required. New substation above existing power plant.	Assume $2 million for transmission line modifications, $7 million for station upgrades, and $4.3 million for Cliff substation modifications.	Part of Generation Interconnect Cluster Study. No further backbone upgrades required.
Hydro—Hydrokinetic (In stream)				
1	$100	Assume minor upgrades required to distribution feeder or substation.	Assume $100k in substation upgrades.	No backbone upgrades required.
ICE Thermal Storage				
10	$0	No transmission upgrades required.	No transmission upgrades required.	No backbone upgrades required.
Natural Gas—Simple Cycle Combustion Turbine (SCCT) Aeroderivative				
47	$46	Assume plant located at or near existing Bennett Mountain plant. Capacity would fit within existing transmission system between Bennett Mountain and Boise.	New 230-kV substation terminal and station modifications.	No backbone upgrades required.

Capacity (MW Rating)	Overnight Transmission Capital Cost/kW[1]	Cost Assumptions Notes	Local Interconnection Assumptions	Backbone Transmission Assumptions
Natural Gas—SCCT Frame F Class (Idaho Power's peaker plants use this technology)				
170	$194	Build new facility south of Boise (assume Simco Road area) with new 230-kV switching station; 22-mile, 230-kV line to Boise Bench Substation, and 230-kV double circuit in/out of Danskin–Hubbard 230-kV line.	New 230-kV switching station with a 22-mile, 230-kV line to Boise Bench Substation and 1 mile, 23-kV double circuit in/out of Danksin–Hubbard 230-kV line.	No backbone upgrades required.
Natural Gas—Reciprocating Gas Engine Wartsila 34SG				
4.1	$73	Assume distribution feeder location with no backbone transmission upgrades required.	Assume $300k of distribution feeder upgrades.	No backbone upgrades required.
Natural Gas—CCCT (1x1) F Class with Duct Firing				
270	$122	Build new facility south of Boise (assume Simco Road area) with new 230-kV switching station; 22-mile, 230-kV line to Boise Bench Substation, and 230-kV double circuit in/out of Danskin–Hubbard 230-kV line.	New 230-kV switching station with a 22-mile, 230-kV line to Boise Bench Substation and 1 mile, 23-kV double circuit in/out of Danksin–Hubbard 230-kV line.	No backbone upgrades required.
Natural Gas—CCCT (2x1) F Class				
580	$101	Build new facility south of Boise (assume Simco Road area) with new 230-kV switching station; 22-mile, 230-kV line to Boise Bench Substation, and 230-kV double circuit in/out of Danskin–Hubbard 230-kV line.	New 230-kV switching station with a 22-mile; 230-kV line to Boise Bench Substation and 28-mile, 230-kV line to Hubbard Substation.	No backbone upgrades required. Entire project assumed as backbone upgrade.
Natural Gas—Combined Heat and Power (CHP)				
45	$57	Assume 0.5 mile tap to existing 138-kV line and new 138-kV source substation (or large upgrade to existing substation).	Assume 0.5 mile tap to existing 138-kV line and new 138-kV source substation.	No backbone upgrades required.
Nuclear—Small Modular Reactor (SMR)				
45	$358	Tie into nearby 230-kV transmission substation. Backbone transmission uprgrades required.	Assume 2 mile, 138-kV interconnection to existing Antelope substation and one new 138-kV terminal.	Pro rata share of Gateway West upgrade from Populus to Cedar Hill to Hemingway. Assume 2.5% ownership of the 280-mile Gateway West segments from Populus to Cedar Hill and Cedar Hill to Hemingway.
Nuclear—SMR				
250	$520	Tie into nearby 230-kV transmission substation. Build new 55 mile, 230-kV line. Backbone transmission uprgrades required.	Two 2-mile, 138-kV lines to interconnect to Antelope Substation. New 230-kV transformer terminal. New parallel 55-mile, 230-kV line from Antelope to Brady Substation. New 230-kV terminal at Brady Substation.	Pro rata share of Gateway West upgrade from Populus to Cedar hill to Hemingway. Assume 12.5% ownership of the 280-mile Gateway West segments from Populus to Cedar Hill and Cedar Hill to Hemingway.
Nuclear—Advanced Nuclear				
1,100	$441	Two new 345kV transmission lines required. One 55 mile line from site to Borah Substation. One 85 mile line from site to Kinport Substation via Goshen Substation.	New 345 kV station. New 55 mile 345kV transmission line to existing Borah substation and new 345kV line terminal. New 85 mile transmission line to existing Kinport Substation through existing Goshen Substation and three new 345 kV line terminals.	Pro rata share of Gateway West upgrade from Populus to Cedar hill to Hemingway. Assume 50% ownership of the 280 mile Gateway West segments from Populus to Cedar Hill and Cedar Hill to Hemingway.
Pumped Storage—new upper reservoir and new generation/pumping plant (pumping water from an existing lower reservoir to a new upper reservoir then running the water through a new power plant)				
100	$1,095	Tie into existing Oxbow 230-/ 138-kV switchyard. New 230-kV transmission line required from Oxbow to Treasure Valley (no existing backbone capacity).	Assume 0.5 mile tap off of Oxbow 138-kV line.	New 110 mile, 230-kV line from Oxbow to Treasure Valley.

Capacity (MW Rating)	Overnight Transmission Capital Cost/kW[1]	Cost Assumptions Notes	Local Interconnection Assumptions	Backbone Transmission Assumptions
Solar Thermal—Solar Power Tower with storage				
100	$330	Assume Mountain Home desert area with 20-mile, 138-kV line to new substation intersecting existing Danskin—Hubbard 230-kV line.	New 230-kV switching station with a 22-mile, 230-kV line to Boise Bench Substation and 1-mile, 230-kV double circuit in/out of Danskin–Hubbard 230-kV line.	No backbone upgrades required.
Solar PV—Distributed Residential Fixed-Tilt (S Orientation)				
10	$0	Assume that no upgrades are required for small residential installations.	Assume that no upgrades are required for small residential installations.	No backbone upgrades required.
Solar PV—Distributed C&I Fixed-Tilt (S Orientation)				
10	$0	Assume that no upgrades are required for small C&I installations.	Assume that no upgrades are required for small C&I installations.	No backbone upgrades required.
Solar PV—Distributed C&I Fixed-Tilt (SW Orientation)				
10	$0	Assume that no upgrades are required for small C&I installations.	Assume that no upgrades are required for small C&I installations.	No backbone upgrades required.
Solar PV—Utility Scale Fixed-Tilt (S Orientation)				
10	$305	Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250k communication infrastructure upgrades.	Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250 communication infrastructure upgrades.	Assume that no backbone upgrades are required for 10 MW (depending on point in time, assumption may not be valid if PURPA projects are constructed in the same geographic area).
Solar PV—Utility Scale Fixed-Tilt (SW Orientation)				
10	$305	Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250k communication infrastructure upgrades.	Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250 communication infrastructure upgrades.	Assume that no backbone upgrades are required for 10 MW (depending on point in time, assumption may not be valid if PURPA projects are constructed in the same geographic area).
Solar PV—Utility Scale 1-Axis Tracking				
10	$305	Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250k communication infrastructure upgrades.	Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250 communication infrastructure upgrades.	Assume that no backbone upgrades are required for 10 MW (depending on point in time, assumption may not be valid if PURPA projects are constructed in the same geographic area).
Solar PV—Utility Scale 2-Axis Tracking				
10	$305	Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250k communication infrastructure upgrades.	Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250 communication infrastructure upgrades.	Assume that no backbone upgrades are required for 10 MW (depending on point in time, assumption may not be valid if PURPA projects are constructed in the same geographic area).
Transmission—Boardman to Hemingway				
Inbound 350—Average 500—Summer 350—Winter	$711	Per the B2H Funding Agreement, Idaho Power's share of the project is roughly 21.2% of total project cost. Assume approximately $16 million in B2H 230-kV integration costs.	New 230-kV transmission circuit from Hemingway Substation to Bowmont Substation. New 230-kV line from Bowmont Substation to Hubbard Substation and 138-kV line re-configuration.	Pro-rata share of B2H project.
Wind—Idaho				
100	$330	Assume location near Midpoint Substation or Justice Substation. Estimated $1.5 million for upgrades at Midpoint or Justice Substation plus 100 MW pro-rata share of 2,000-MW Gateway West 500-kV project from Midpoint/Cedar Hill Substation to Hemingway Substation.	Assume 10 miles of 138-kV local transmission to project site with 138-kV substation and 138-/ 230-kV transformer.	Assume $1.5 million for upgrades at Midpoint Substation or Justice Substation. Assume 5% share of estimated $425 million Gateway West 500kV project from Midpoint/Cedar Hill Substation to Hemingway Substation.

Levelized Cost of Production

30-Year Levelized Cost of Production (at stated capacity factors)

Supply-Side Resources	Cost of Capital	Non-Fuel O&M[1]	Fuel	Wholesale Energy	Net of Tax Credit/Steam sales/Integration	Total Cost per MWh	Capacity Factor
Advanced Nuclear (250 MW)	$88	$25	$7	$0	$0	$119	90%
Battery Storage (6 MW)	$216	$24	$0	$46	$0	$285	25%
Biomass Direct—Woody Residue (35 MW)	$44	$40	$19	$0	$0	$102	85%
Biomass Indirect— Anaerobic Digester (3 MW)	$87	$33	$0	$0	$0	$119	75%
Boardman to Hemingway (350 MW)	$21	$2	$0	$54	$0	$78	33%
Canal Drop Hydro (1.28 MW)	$135	$24	$0	$0	$0	$159	33%
CCCT (1x1) F Class with Duct Firing (270 MW)	$25	$6	$49	$0	$0	$79	70%
CCCT (2x1) F Class (580 MW)	$20	$7	$48	$0	$0	$75	70%
CHP (45 MW)	$32	$19	$46	$0	-$16	$81	80%
IGCC (580 MW)	$71	$28	$17	$0	$0	$116	75%
IGCC with Carbon Capture (580 MW)	$127	$37	$21	$0	$0	$184	75%
Geothermal (30 MW)	$64	$43	$0	$0	-$6	$101	90%
ICE Thermal Storage (10 MW)	$171	$53	$0	$0	$0	$224	10%
Pumped Storage (150 MW)	$304	$42	$0	$57	$0	$403	25%
Reciprocating Gas Engine (18.8 MW)	$66	$14	$55	$0	$0	$136	10%
SCCT—Aeroderivative (47 MW)	$124	$59	$67	$0	$0	$250	10%
SCCT—Frame F Class (170 MW)	$118	$24	$76	$0	$0	$219	10%
Shoshone Falls Upgrade (49.5 MW)	$66	$8	$0	$0	$0	$74	43%
Small Modular Nuclear (250 MW)	$96	$39	$208	$0	$0	$343	95%
Solar Power Tower (110 MW)	$325	$69	$0	$0	-$21	$372	28%
Solar PV—Distr Residential Fixed S (10 MW)	$212	$33	$0	$0	-$11	$234	20%
Solar PV—Distr C&I Fixed S (10 MW)	$148	$20	$0	$0	-$6	$162	21%
Solar PV—Distr C&I Fixed SW (10 MW)	$155	$21	$0	$0	-$6	$170	20%
Solar PV—Utility Scale Fixed S (10 MW)	$103	$16	$0	$0	-$2	$118	21%
Solar PV—Utility Scale Fixed SW (10 MW)	$109	$17	$0	$0	-$2	$124	20%
Solar PV—Utility Scale 1-Axis Tracking (10 MW)	$92	$17	$0	$0	-$1	$109	27%
Solar PV—Utility Scale 2-Axis Tracking (10 MW)	$88	$18	$0	$0	$0	$105	30%
TurboPhase (23.6 MW)	$45	$8	$58	$0	$0	$111	10%
Wind (100 MW)	$86	$28	$0	$0	$21	$135	28%

[1] Non Fuel O&M includes fixed and variable costs, property taxes.

30-Year Levelized Capacity (fixed) Cost per kW/Month					
Supply-Side Resources	**Cost of Capital**	**Non-Fuel O&M**	**Fuel**	**Net of Tax Credit/Steam sales/Integration**	**Total Cost per kW**
Advanced Nuclear (250 MW)	$57	$16	$0	$0	$73
Battery Storage (6 MW)	$39	$4	$0	$0	$44
Biomass Direct—Woody Residue (35 MW)	$27	$12	$0	$0	$40
Biomass Indirect—Anaerobic Digester (3 MW)	$48	$8	$0	$0	$55
Boardman to Hemingway (350 MW)	$5	$1	$0	$0	$6
Canal Drop Hydro (1.28 MW)	$32	$6	$0	$0	$38
CCCT (1x1) F Class with Duct Firing (270 MW)	$13	$2	$0	$0	$14
CCCT (2x1) F Class (580 MW)	$10	$1	$0	$0	$11
CHP (45 MW)	$18	$7	$0	$0	$26
IGCC (580 MW)	$39	$10	$0	$0	$49
IGCC with Carbon Capture (580 MW)	$69	$14	$0	$0	$83
Geothermal (30 MW)	$42	$0	$0	$0	$42
ICE Thermal Storage (10 MW)	$13	$4	$0	$0	$17
Pumped Storage (150 MW)	$55	$8	$0	$0	$63
Reciprocating Gas Engine (18.8 MW)	$5	$1	$0	$0	$5
SCCT—Aeroderivative (47 MW)	$9	$4	$0	$0	$13
SCCT—Frame F Class (170 MW)	$9	$1	$0	$0	$10
Shoshone Falls Upgrade (49.5 MW)	$21	$2	$0	$0	$23
Small Modular Nuclear (250 MW)	$66	$6	$0	$0	$72
Solar Power Tower (110 MW)	$66	$7	$0	$0	$73
Solar PV—Distr Residential Fixed S (10 MW)	$31	$2	$0	$0	$33
Solar PV—Distr C&I Fixed S (10 MW)	$22	$1	$0	$0	$23
Solar PV—Distr C&I Fixed SW (10 MW)	$22	$1	$0	$0	$23
Solar PV—Utility Scale Fixed S (10 MW)	$16	$1	$0	$0	$17
Solar PV—Utility Scale Fixed SW (10 MW)	$16	$1	$0	$0	$17
Solar PV—Utility Scale 1-Axis Tracking (10 MW)	$18	$2	$0	$0	$20
Solar PV—Utility Scale 2-Axis Tracking (10 MW)	$19	$2	$0	$0	$21
TurboPhase (23.6 MW)	$3	$0	$0	$0	$4
Wind (100 MW)	$18	$6	$0	$0	$23

Peak-Hour Capacity Credit (Contribution to Peak)—Solar and Wind Resources

Peak hour capacity credit (contribution to peak) for new IRP intermittent generation resources:

New IRP intermittent generation—Peak hour capacity credit	
Resource	**Peak Hour Capacity Credit**
PV solar south orientation	28.4%
PV solar southwest orientation	45.4%
PV solar single-axis tracking	51.3%
Wind	5.0%

Energy Shape—Solar

2015 IRP Assumed Solar Capacity Factors

Month	Utility Scale, Single Axis Tracking	Residential, Fixed Tilt
January	12%	7%
February	19%	11%
March	26%	16%
April	32%	20%
May	37%	23%
June	41%	25%
July	42%	26%
August	39%	24%
September	33%	20%
October	25%	16%
November	14%	9%
December	11%	7%
Annual Capacity Factor	**27.5%**	**17.0%**

Schedule 87—Integration Costs for Solar and Wind Resources

Solar

0–100 MW Solar Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates*
2014	0.54	2014	0.43
2015	0.56	2015	0.44
2016	0.58	2016	0.46
2017	0.59	2017	0.47
2018	0.61	2018	0.48
2019	0.63	2019	0.50
		2020	0.51
		2021	0.53
		2022	0.54
		2023	0.56
		2024	0.58
		2025	0.60
		2026	0.61
		2027	0.63
		2028	0.65
		2029	0.67
		2030	0.69
		2031	0.71
		2032	0.73
		2033	0.75
		2034	0.78
		2035	0.80
		2036	0.82
		2037	0.85
		2038	0.87
		2039	0.90

*$/MWh

101–200 MW Solar Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	1.49	2014	1.18
2015	1.53	2015	1.22
2016	1.58	2016	1.25
2017	1.63	2017	1.29
2018	1.68	2018	1.33
2019	1.73	2019	1.37
		2020	1.41
		2021	1.45
		2022	1.50
		2023	1.54
		2024	1.59
		2025	1.63
		2026	1.68
		2027	1.73
		2028	1.79
		2029	1.84
		2030	1.89
		2031	1.95
		2032	2.01
		2033	2.07
		2034	2.13
		2035	2.20
		2036	2.26
		2037	2.33
		2038	2.40
		2039	2.47

*$/MWh

201–300 MW Solar Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	2.32	2014	1.84
2015	2.39	2015	1.89
2016	2.46	2016	1.95
2017	2.54	2017	2.01
2018	2.61	2018	2.07
2019	2.69	2019	2.13
		2020	2.20
		2021	2.26
		2022	2.33
		2023	2.40
		2024	2.47
		2025	2.55
		2026	2.62
		2027	2.70
		2028	2.78
		2029	2.87
		2030	2.95
		2031	3.04
		2032	3.13
		2033	3.23
		2034	3.32
		2035	3.42
		2036	3.52
		2037	3.63
		2038	3.74
		2039	3.85

*$/MWh

301–400 MW Solar Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	3.12	2014	2.48
2015	3.22	2015	2.55
2016	3.32	2016	2.63
2017	3.41	2017	2.71
2018	3.52	2018	2.79
2019	3.62	2019	2.87
		2020	2.96
		2021	3.05
		2022	3.14
		2023	3.23
		2024	3.33
		2025	3.43
		2026	3.53
		2027	3.64
		2028	3.75
		2029	3.86
		2030	3.97
		2031	4.09
		2032	4.22
		2033	4.34
		2034	4.47
		2035	4.61
		2036	4.75
		2037	4.89
		2038	5.03
		2039	5.19

*$/MWh

401–500 MW Solar Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	3.94	2014	3.12
2015	4.06	2015	3.22
2016	4.18	2016	3.31
2017	4.31	2017	3.41
2018	4.44	2018	3.52
2019	4.57	2019	3.62
		2020	3.73
		2021	3.84
		2022	3.96
		2023	4.08
		2024	4.20
		2025	4.32
		2026	4.45
		2027	4.59
		2028	4.72
		2029	4.87
		2030	5.01
		2031	5.16
		2032	5.32
		2033	5.48
		2034	5.64
		2035	5.81
		2036	5.98
		2037	6.16
		2038	6.35
		2039	6.54

*$/MWh

501–600 MW Solar Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	4.76	2014	3.78
2015	4.91	2015	3.89
2016	5.05	2016	4.01
2017	5.21	2017	4.13
2018	5.36	2018	4.25
2019	5.52	2019	4.38
		2020	4.51
		2021	4.64
		2022	4.78
		2023	4.93
		2024	5.07
		2025	5.23
		2026	5.38
		2027	5.55
		2028	5.71
		2029	5.88
		2030	6.06
		2031	6.24
		2032	6.43
		2033	6.62
		2034	6.82
		2035	7.02
		2036	7.24
		2037	7.45
		2038	7.68
		2039	7.91

*$/MWh

601–700 MW Solar Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	5.54	2014	4.39
2015	5.71	2015	4.53
2016	5.88	2016	4.66
2017	6.06	2017	4.80
2018	6.24	2018	4.95
2019	6.43	2019	5.09
		2020	5.25
		2021	5.40
		2022	5.57
		2023	5.73
		2024	5.91
		2025	6.08
		2026	6.26
		2027	6.45
		2028	6.65
		2029	6.85
		2030	7.05
		2031	7.26
		2032	7.48
		2033	7.70
		2034	7.94
		2035	8.17
		2036	8.42
		2037	8.67
		2038	8.93
		2039	9.20

*$/MWh

701–800 MW Solar Capacity Penetration Level**			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	6.70	2014	5.31
2015	6.91	2015	5.47
2016	7.11	2016	5.64
2017	7.33	2017	5.81
2018	7.55	2018	5.98
2019	7.77	2019	6.16
		2020	6.35
		2021	6.54
		2022	6.73
		2023	6.93
		2024	7.14
		2025	7.36
		2026	7.58
		2027	7.80
		2028	8.04
		2029	8.28
		2030	8.53
		2031	8.78
		2032	9.05
		2033	9.32
		2034	9.60
		2035	9.89
		2036	10.18
		2037	10.49
		2038	10.80
		2039	11.13

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

801–900 MW Solar Capacity Penetration Level**			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	7.98	2014	6.32
2015	8.21	2015	6.51
2016	8.46	2016	6.71
2017	8.71	2017	6.91
2018	8.98	2018	7.11
2019	9.25	2019	7.33
		2020	7.55
		2021	7.77
		2022	8.01
		2023	8.25
		2024	8.50
		2025	8.75
		2026	9.01
		2027	9.28
		2028	9.56
		2029	9.85
		2030	10.14
		2031	10.45
		2032	10.76
		2033	11.08
		2034	11.42
		2035	11.76
		2036	12.11
		2037	12.48
		2038	12.85
		2039	13.24

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

901–1,000 MW Solar Capacity Penetration Level**			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	9.52	2014	7.54
2015	9.80	2015	7.77
2016	10.10	2016	8.00
2017	10.40	2017	8.24
2018	10.71	2018	8.49
2019	11.03	2019	8.74
		2020	9.01
		2021	9.28
		2022	9.55
		2023	9.84
		2024	10.14
		2025	10.44
		2026	10.75
		2027	11.08
		2028	11.41
		2029	11.75
		2030	12.10
		2031	12.47
		2032	12.84
		2033	13.23
		2034	13.62
		2035	14.03
		2036	14.45
		2037	14.89
		2038	15.33
		2039	15.79

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

1,001–1,100 MW Solar Capacity Penetration Level**			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	11.38	2014	9.02
2015	11.72	2015	9.29
2016	12.07	2016	9.56
2017	12.43	2017	9.85
2018	12.80	2018	10.15
2019	13.19	2019	10.45
		2020	10.77
		2021	11.09
		2022	11.42
		2023	11.76
		2024	12.12
		2025	12.48
		2026	12.85
		2027	13.24
		2028	13.64
		2029	14.05
		2030	14.47
		2031	14.90
		2032	15.35
		2033	15.81
		2034	16.28
		2035	16.77
		2036	17.28
		2037	17.79
		2038	18.33
		2039	18.88

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

1,101–1,200 MW Solar Capacity Penetration Level**			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	13.61	2014	10.78
2015	14.01	2015	11.11
2016	14.43	2016	11.44
2017	14.87	2017	11.78
2018	15.31	2018	12.14
2019	15.77	2019	12.50
		2020	12.88
		2021	13.26
		2022	13.66
		2023	14.07
		2024	14.49
		2025	14.93
		2026	15.37
		2027	15.84
		2028	16.31
		2029	16.80
		2030	17.30
		2031	17.82
		2032	18.36
		2033	18.91
		2034	19.48
		2035	20.06
		2036	20.66
		2037	21.28
		2038	21.92
		2039	22.58

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

1,201–1,300 MW Solar Capacity Penetration Level**			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	16.26	2014	12.89
2015	16.75	2015	13.28
2016	17.25	2016	13.67
2017	17.77	2017	14.08
2018	18.30	2018	14.51
2019	18.85	2019	14.94
		2020	15.39
		2021	15.85
		2022	16.33
		2023	16.82
		2024	17.32
		2025	17.84
		2026	18.38
		2027	18.93
		2028	19.50
		2029	20.08
		2030	20.68
		2031	21.30
		2032	21.94
		2033	22.60
		2034	23.28
		2035	23.98
		2036	24.70
		2037	25.44
		2038	26.20
		2039	26.99

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

1,301–1,400 MW Solar Capacity Penetration Level**			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	19.40	2014	15.38
2015	19.98	2015	15.84
2016	20.58	2016	16.31
2017	21.20	2017	16.80
2018	21.84	2018	17.31
2019	22.49	2019	17.83
		2020	18.36
		2021	18.91
		2022	19.48
		2023	20.06
		2024	20.66
		2025	21.28
		2026	21.92
		2027	22.58
		2028	23.26
		2029	23.96
		2030	24.67
		2031	25.41
		2032	26.18
		2033	26.96
		2034	27.77
		2035	28.60
		2036	29.46
		2037	30.35
		2038	31.26
		2039	32.19

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

1,301–1,400 MW Solar Capacity Penetration Level**			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	23.07	2014	18.29
2015	23.77	2015	18.84
2016	24.48	2016	19.40
2017	25.21	2017	19.98
2018	25.97	2018	20.58
2019	26.75	2019	21.20
		2020	21.84
		2021	22.49
		2022	23.17
		2023	23.86
		2024	24.58
		2025	25.31
		2026	26.07
		2027	26.86
		2028	27.66
		2029	28.49
		2030	29.35
		2031	30.23
		2032	31.13
		2033	32.07
		2034	33.03
		2035	34.02
		2036	35.04
		2037	36.09
		2038	37.18
		2039	38.29

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

Wind

0–100 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	0.27	2014	0.21
2015	0.27	2015	0.22
2016	0.28	2016	0.23
2017	0.29	2017	0.23
2018	0.30	2018	0.24
2019	0.31	2019	0.25
		2020	0.25
		2021	0.26
		2022	0.27
		2023	0.28
		2024	0.29
		2025	0.29
		2026	0.30
		2027	0.31
		2028	0.32
		2029	0.33
		2030	0.34
		2031	0.35
		2032	0.36
		2033	0.37
		2034	0.38
		2035	0.40
		2036	0.41
		2037	0.42
		2038	0.43
		2039	0.45

*$/MWh

101–200 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	1.22	2014	0.98
2015	1.25	2015	1.00
2016	1.29	2016	1.04
2017	1.33	2017	1.07
2018	1.37	2018	1.10
2019	1.41	2019	1.13
		2020	1.16
		2021	1.20
		2022	1.24
		2023	1.27
		2024	1.31
		2025	1.35
		2026	1.39
		2027	1.43
		2028	1.48
		2029	1.52
		2030	1.57
		2031	1.61
		2032	1.66
		2033	1.71
		2034	1.76
		2035	1.81
		2036	1.87
		2037	1.93
		2038	1.98
		2039	2.04

*$/MWh

201–300 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	2.78	2014	2.23
2015	2.87	2015	2.30
2016	2.95	2016	2.37
2017	3.04	2017	2.44
2018	3.13	2018	2.51
2019	3.23	2019	2.59
		2020	2.67
		2021	2.75
		2022	2.83
		2023	2.92
		2024	3.00
		2025	3.09
		2026	3.19
		2027	3.28
		2028	3.38
		2029	3.48
		2030	3.59
		2031	3.69
		2032	3.80
		2033	3.92
		2034	4.04
		2035	4.16
		2036	4.28
		2037	4.41
		2038	4.54
		2039	4.68

*$/MWh

301–400 MW Solar Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	4.95	2014	3.98
2015	5.10	2015	4.10
2016	5.26	2016	4.22
2017	5.41	2017	4.35
2018	5.58	2018	4.48
2019	5.74	2019	4.61
		2020	4.75
		2021	4.89
		2022	5.04
		2023	5.19
		2024	5.34
		2025	5.51
		2026	5.67
		2027	5.84
		2028	6.02
		2029	6.20
		2030	6.38
		2031	6.57
		2032	6.77
		2033	6.97
		2034	7.18
		2035	7.40
		2036	7.62
		2037	7.85
		2038	8.08
		2039	8.33

*$/MWh

401–500 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	7.71	2014	6.19
2015	7.95	2015	6.38
2016	8.18	2016	6.57
2017	8.43	2017	6.77
2018	8.68	2018	6.97
2019	8.94	2019	7.18
		2020	7.39
		2021	7.62
		2022	7.84
		2023	8.08
		2024	8.32
		2025	8.57
		2026	8.83
		2027	9.09
		2028	9.37
		2029	9.65
		2030	9.94
		2031	10.23
		2032	10.54
		2033	10.86
		2034	11.18
		2035	11.52
		2036	11.86
		2037	12.22
		2038	12.59
		2039	12.96

*$/MWh

501–600 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	11.05	2014	8.87
2015	11.38	2015	9.13
2016	11.72	2016	9.41
2017	12.07	2017	9.69
2018	12.43	2018	9.98
2019	12.81	2019	10.28
		2020	10.59
		2021	10.91
		2022	11.23
		2023	11.57
		2024	11.92
		2025	12.28
		2026	12.64
		2027	13.02
		2028	13.41
		2029	13.82
		2030	14.23
		2031	14.66
		2032	15.10
		2033	15.55
		2034	16.02
		2035	16.50
		2036	16.99
		2037	17.50
		2038	18.03
		2039	18.57

*$/MWh

601–700 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	14.94	2014	11.99
2015	15.39	2015	12.35
2016	15.85	2016	12.72
2017	16.33	2017	13.10
2018	16.82	2018	13.50
2019	17.32	2019	13.90
		2020	14.32
		2021	14.75
		2022	15.19
		2023	15.65
		2024	16.12
		2025	16.60
		2026	17.10
		2027	17.61
		2028	18.14
		2029	18.68
		2030	19.24
		2031	19.82
		2032	20.42
		2033	21.03
		2034	21.66
		2035	22.31
		2036	22.98
		2037	23.67
		2038	24.38
		2039	25.11

*$/MWh

701–800 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	19.38	2014	15.55
2015	19.96	2015	16.02
2016	20.56	2016	16.50
2017	21.17	2017	17.00
2018	21.81	2018	17.51
2019	22.46	2019	18.03
		2020	18.57
		2021	19.13
		2022	19.70
		2023	20.29
		2024	20.90
		2025	21.53
		2026	22.18
		2027	22.84
		2028	23.53
		2029	24.23
		2030	24.96
		2031	25.71
		2032	26.48
		2033	27.27
		2034	28.09
		2035	28.93
		2036	29.80
		2037	30.70
		2038	31.62
		2039	32.57

*$/MWh

801–900 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	24.34	2014	19.54
2015	25.07	2015	20.13
2016	25.83	2016	20.73
2017	26.60	2017	21.35
2018	27.40	2018	21.99
2019	28.22	2019	22.65
		2020	23.33
		2021	24.03
		2022	24.75
		2023	25.50
		2024	26.26
		2025	27.05
		2026	27.86
		2027	28.70
		2028	29.56
		2029	30.44
		2030	31.36
		2031	32.30
		2032	33.27
		2033	34.26
		2034	35.29
		2035	36.35
		2036	37.44
		2037	38.56
		2038	39.72
		2039	40.91

*$/MWh

901–1,000 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	29.82	2014	23.94
2015	30.72	2015	24.66
2016	31.64	2016	25.40
2017	32.59	2017	26.16
2018	33.57	2018	26.94
2019	34.57	2019	27.75
		2020	28.59
		2021	29.44
		2022	30.33
		2023	31.24
		2024	32.17
		2025	33.14
		2026	34.13
		2027	35.16
		2028	36.21
		2029	37.30
		2030	38.42
		2031	39.57
		2032	40.76
		2033	41.98
		2034	43.24
		2035	44.54
		2036	45.87
		2037	47.25
		2038	48.66
		2039	50.12

*$/MWh

1,001–1,100 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	35.81	2014	28.74
2015	36.88	2015	29.60
2016	37.99	2016	30.49
2017	39.13	2017	31.41
2018	40.30	2018	32.35
2019	41.51	2019	33.32
		2020	34.32
		2021	35.35
		2022	36.41
		2023	37.50
		2024	38.63
		2025	39.78
		2026	40.98
		2027	42.21
		2028	43.47
		2029	44.78
		2030	46.12
		2031	47.51
		2032	48.93
		2033	50.40
		2034	51.91
		2035	53.47
		2036	55.07
		2037	56.72
		2038	58.43
		2039	60.18

*$/MWh

1,101–1,200 MW Wind Capacity Penetration Level			
Levelized		Non Levelized	
On-line Year	20-Year Contract Term Levelized Rates*	Contract year	Non-Levelized Rates
2014	42.27	2014	33.93
2015	43.54	2015	34.95
2016	44.85	2016	36.00
2017	46.19	2017	37.08
2018	47.58	2018	38.19
2019	49.01	2019	39.34
		2020	40.52
		2021	41.73
		2022	42.98
		2023	44.27
		2024	45.60
		2025	46.97
		2026	48.38
		2027	49.83
		2028	51.33
		2029	52.87
		2030	54.45
		2031	56.09
		2032	57.77
		2033	59.50
		2034	61.29
		2035	63.12
		2036	65.02
		2037	66.97
		2038	68.98
		2039	71.05

*$/MWh

PURPA Reference Data

The following information is provided for PURPA reference purposes.

1. Preferred portfolio: Portfolio P6(b)

Resource portfolio P6(b)

Date	Resource	Installed Capacity	Peak-Hour Capacity
2025	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2025	Retire North Valmy (both units)	(262 MW)	(262 MW)
2030	Demand response	60 MW	60 MW
2030	Ice-based TES	20 MW	20 MW
2031	CCCT	300 MW	300 MW
		Total retired capacity	(262 MW)
		Total added capacity	880 MW
		Net peak-hour capacity	618 MW

2. Deficiency period under preferred portfolio

   1st capacity deficit = (14) MW July 2025
   1st energy deficit = (34) MW July 2026

   Note—Above deficits are based on 461 MW of installed PV solar capacity under contract at the time of portfolio design, and do not reflect the April 2015 cancellation of 141 MW of PV solar PURPA contracts. With removal of the 141 MW of PV solar PURPA contracts, the first deficits for capacity and energy are respectively (47) MW in July 2024 and (76) MW in July 2026.

3. Intermittent generation integration costs

   See integration cost schedule included in *Appendix C—Technical Appendix*, section *Schedule 87—Integration Costs for Solar and Wind Resources*.

Renewable Energy Certificate Price Forecast

Year	Nominal ($/MWh)
2015	$3.04
2016	$3.06
2017	$3.95
2018	$3.95
2019	$4.70
2020	$5.23
2021	$5.48
2022	$5.73
2023	$5.98
2024	$6.33
2025	$6.68
2026	$7.05
2027	$7.45
2028	$7.83
2029	$8.22
2030	$8.64
2031	$9.06
2032	$9.49
2033	$9.93
2034	$10.38

JIM BRIDGER UNITS 3 AND 4 SELECTIVE CATALYTIC REDUCTION ANALYSIS

The 2015 Jim Bridger Plant units 3 and 4 Selective Catalytic Reduction (SCR) Analysis (2015 SCR Analysis) is intended to satisfy the conditions set forth by the Idaho Public Utilities Commission (IPUC) in Order No. 32929 approving the Certificate of Public Convenience and Necessity (CPCN) for the investment in SCR controls on Jim Bridger units 3 and 4. Commission Order No. 32929 directs Idaho Power to be "continuously analyzing the impact of changing environmental regulations on its upgrade project." (Order No. 32929, p. 11). In addition to the above requirement, the company files quarterly reports in Docket No. IPC-E-13-16 providing updates as to the current status of environmental policies that are relevant to the construction of the SCR controls at Jim Bridger units 3 and 4, construction progress updates, and any other pertinent updates related to the SCRs.

The company's 2015 SCR Analysis evaluates the impacts of new environmental regulations proposed since the company filed its Coal Unit Environmental Analysis in 2013 (2013 Coal Study) as well as the cost-effectiveness of continuing the installation of the SCRs compared to shutting down units 3 and 4 and replacing that generation with an alternate generation resource.

Background

The Jim Bridger coal-fired power plant (Jim Bridger Plant) consists of four units and is located near Rock Springs, Wyoming. Idaho Power owns one-third of the Jim Bridger Plant with the other two-thirds owned by PacifiCorp. The plant is maintained and operated by PacifiCorp. Units 3 and 4 have nominal net generation capacities of 523 and 530 megawatts (MW) respectively, and Idaho Power's share of the generation capacity is approximately 351 MW from both units.

Currently, the Jim Bridger Plant is required to meet SCR-based emission limits of 0.07 lb/MMBtu for nitrogen oxides (NOx) for all four units to comply with the U.S. Environmental Protection Agency (EPA) Regional Haze (RH) rules and the resulting Wyoming State Implementation Plan (SIP). SCRs are used to facilitate a chemical reaction between NOx (created during combustion) and ammonia to create nitrogen and water.

In 2013, as part of the 2011 IRP Update, the company filed its 2013 Coal Study which examined future investments required for environmental compliance in existing coal units and compared those investments to the costs of alternative replacement resources. The results of the 2013 Coal Study analysis for Jim Bridger identified additional investments in environmental controls on all four Jim Bridger units as prudent decisions that represented the lowest cost and least-risk option when compared to the other investment alternatives. The company used the results of the 2013 Coal Study to support its Application for approval of a CPCN for the investment in SCRs on units 3 and 4. Subsequently, the IPUC issued its approval of the CPCN in December 2013 and construction of the SCRs began shortly after.

SCR Construction Progress Update

The major components of an SCR upgrade consist of: large particle ash collection, ammonia injection grid, the SCR reactor vessel (which contains the catalyst modules), and all added flue gas path ductwork. In addition to the SCR, Unit 4 will require larger induced draft fans to compensate for the flow restriction of the SCR reactor.

Construction of the SCRs is ongoing; as of May 2015, 99 percent of the 2,588 tons of the Unit 3 structural steel and 83 percent of the 7,570 linear feet of the SCR reactor piping has been completed. For Unit 4, 63 percent of the 3,031 tons of structural steel has been completed.

The Unit 3 SCR is scheduled to be completed by November 5, 2015, with a Wyoming SIP compliance deadline of December 31, 2015. Unit 4 is scheduled for completion by November 3, 2016, with a Wyoming SIP compliance date of December 31, 2016.

2015 Jim Bridger Units 3 and 4 SCR Analysis

The 2015 SCR Analysis re-examines the previous conclusion that installation of the SCRs on units 3 and 4 is the least-cost and least-risk means of ensuring that units 3 and 4 comply with state and federal emissions regulations. The 2015 SCR Analysis had two objectives:

1. Evaluate changes in environmental requirements since the 2013 Coal Study that may have an impact on the cost-effectiveness and/or viability of the SCRs on units 3 and 4, and

2. Determine the cost-effectiveness of installing the SCRs compared to the fixed costs of replacing the coal-fired generation from units 3 and 4 with a combined-cycle combustion turbine (CCCT) generation resource alternative.

Changes in Environmental Regulations

On June 2, 2014, the EPA released its draft proposal to regulate carbon dioxide (CO_2) emissions from existing power plants. In the rule, the EPA proposes enforceable CO_2 performance goals that are based on a bottom-up, multi-factor analysis that reflects a system-wide approach of four building blocks, including increasing efficiency of the existing coal-fired generation, natural gas re-dispatch, renewable energy deployment, and demand-side energy efficiency. The goals take the form of state-wide carbon intensity rates for the state's electric power sector. Each state's goal reflects an emissions target (stated as lbs of CO_2/MWh of generation) that EPA has determined to be reasonable based upon the theoretical application of the "best system of emission reduction" for fossil-fueled power plants.

The proposal directs states to submit plans for meeting their goals. States may also work together to submit a single, coordinated multi-state plan. States and multi-state groups have a June 2016 deadline for submitting their plans, with the possibility of a 1- or 2-year extension depending on the plan type. Under the proposed rule, each state's plan must be approved by the EPA, based on modeling projections by the state that demonstrate, to the agency's satisfaction, that the plan will be adequate to meet EPA's determination of the state's interim and final goals. State plans do not need to rely upon the four building block measures EPA used to construct each state's goal. Rather, each state has relatively broad discretion to determine the policy measures on which it will rely to meet its goal.

There are several alternative approaches to 111(d) compliance. The individual states where the generators are physically located will determine the final impact to each of the affected units. Idaho Power has reviewed the Wyoming intensity targets and alternative approaches to compliance, and the company believes that there will be minimal impact on the normal operation of Jim Bridger units 3 and 4.

SCR Cost-Effectiveness

To determine if the SCRs on units 3 and 4 continue to be the least-cost and least-risk option for compliance, the 2015 SCR Analysis compared the costs of two compliance options:

Option 1—Continue to install SCRs for compliance with state and federal environmental regulations

Option 2—Stop installation of SCRs and replace the coal-fired generation from units 3 and 4 with a CCCT.

Overall Analysis Methodology

The study approach examined the costs and benefits of each option. The company's share of the nominal generation capacity at units 3 and 4 of 351 MW was assumed to be replaced with a CCCT with the same capacity. Incremental capital investment and fixed operations and maintenance (O&M) were included in the analysis. In addition, the fuel and variable O&M were forecasted for the duration of the study period to forecast the total cost of generation, both fixed and variable, for each compliance option.

The 2015 SCR Analysis utilized a 20-year study period over which the costs of both options are calculated. One difference between the 2015 SCR Analysis and the 2013 Coal Study is the inclusion of the return on investment in the net present value (NPV) calculations. In the 2013 Coal Study, the Science Applications International Corporation (SAIC) capital evaluation approach evaluated the capital costs of construction *without* the associated return on investment that is included in the company's regulatory revenue requirement determinations.

Option 1 NPV Methodology

The company determined the cost of Option 1 by calculating the revenue requirement of the existing investment in units 3 and 4, incremental capital additions over the study period, the SCR capital costs (total SCR construction costs and fixed O&M) over the study period, and decommissioning costs. The additional costs of fuel and O&M related to operating the units over the study period were added to the revenue requirement of the capital investments.

The revenue requirement associated with the existing investment in units 3 and 4 includes the return on the existing investment for units 3 and 4, O&M, and fuel costs over the study period. The O&M information used in the analysis comes from the company's 10-year budget information from the Jim Bridger Plant forecast through the end of the study period. The company used data from its coal price forecast over the study period to determine the annual fuel expense including transportation costs. The company's coal price forecast is based on long-term contracts for supplying coal to the Jim Bridger Plant. The incremental capital additions include the cost of the SCRs as well as routine capital expenditures for maintenance and repairs throughout the study period. Also included as part of the costs of Option 1 are the decommissioning costs for units 3 and 4 that will be required when the units are retired. The company took the present value of the annual cost stream over the study period to determine the cost of Option 1. The cost of continuing to install the SCRs for compliance is $1.42 billion over the study period.

Option 2 NPV Methodology

The costs of Option 2 is the combination of the costs to shutdown units 3 and 4 and build a CCCT to replace the generation from those shuttered units. The shutdown costs of units 3 and 4 include the accelerated recovery of the existing investment at units 3 and 4, accelerated recovery of the costs-to-date of the SCRs (dollars committed including cancelation penalties as of December 31, 2014), and decommissioning costs. By shutting down units 3 and 4 early, future ongoing capital costs on units 3 and 4 are avoided. The revenue requirement of the CCCT includes construction costs, fixed O&M, and return on investment over a 20-year period. The cost of the CCCT was based on the costs identified in the 2015 IRP for this type of resource. The assumption is that the CCCT would be sized to exactly replace the MW capacity of units 3 and 4. The CCCT in the analysis has an 85 percent capacity factor with an assumed heat rate of 6,714 Btu/kWh. The natural gas price forecast used in the analysis is an Idaho Citygate price forecast based on the 2015 IRP. The Idaho Citygate price is a Henry hub gas price with a Sumas hub differential applied plus transportation costs. It is assumed the CCCT would be sited in a region with access to the Sumas hub natural gas pricing, with additional gas transportation charges and capacity to a generic Idaho Citygate. The costs of shuttering units 3 and 4 and replacing that capacity with a CCCT are $2.496 billion over the study period.

Analysis Results

Over the study period, the NPV of Option 1 is $1.420 billion and the NPV of Option 2 is $2.496 billion. Option 1, continuing to install the SCRs for compliance, is $1.076 billion less than compliance alternative Option 2.

The company performed additional analyses on the results to determine the main drivers of the $1.076 billion difference. As shown in the table below, $793 million was due to higher fuel costs in Option 2, $186 million was due to a higher return on capital investment in Option 2 due to the higher capital costs, O&M costs were $35 million less than Option 1 as a CCCT would be less O&M intensive than the Jim Bridger Plant, and capital costs for Option 2 were $132 million higher.

Option 2 Impact of Various Cost Drivers

Impact from fuel costs:	$793,308,007
Impact from ROI:	185,890,627
Impact from difference in O&M:	(35,319,989)
Impact due to difference in capital costs:	132,407,174
Total	**$1,076,285,819**

Conclusions and Recommendations

Based on the 2015 SCR Analysis, continuing with the installation of the SCRs on units 3 and 4 represents a cost savings of $1.076 billion compared to shuttering units 3 and 4 and replacing that generation with a CCCT resource. The company evaluated the changes in environmental regulations proposed since the 2013 Coal Study and believes there will be little impact to the normal operation of units 3 and 4. The SCRs remain the least-cost and least risk option for compliance and the company will continue the installation of the SCRs on units 3 and 4.

Revenue Requirement Comparison between Jim Bridger Units 3 and 4 SCR Completion and CCCT Replacement

Revenue Requirement on Existing Investments

Year	Existing Investments
2015	$101,017,077
2016	$101,191,683
2017	$102,260,140
2018	$102,958,825
2019	$103,167,948
2020	$94,039,451
2021	$91,247,597
2022	$91,513,087
2023	$94,069,370
2024	$107,116,956
2025	$108,120,849
2026	$109,746,974
2027	$111,413,380
2028	$113,148,724
2029	$114,824,751
2030	$116,577,779
2031	$118,486,952
2032	$120,459,297
2033	$122,496,977
2034	$124,607,408
Total	**$2,148,465,226**

Revenue Requirement on Incremental Investments

	Bridger Capital Forecast	Life (years)	Assumed In-Service	2015	2016	2017	2018	2019
2015	90,802,222	20	12/31/2015	$14,340,755	—	—	—	—
2016	44,787,706	19	12/31/2016	$13,838,158	$7,184,838	—	—	—
2017	13,508,618	18	12/31/2017	$13,335,560	$6,923,888	$2,204,363	—	—
2018	18,268,574	17	12/31/2018	$12,832,963	$6,662,937	$2,121,284	$3,037,499	—
2019	14,439,932	16	12/31/2019	$12,330,366	$6,401,986	$2,038,205	$2,918,537	$2,451,064
2020	9,596,002	15	12/31/2020	$11,827,769	$6,141,035	$1,955,126	$2,799,575	$2,351,156
2021	7,181,971	14	12/31/2021	$11,325,172	$5,880,084	$1,872,047	$2,680,613	$2,251,249
2022	5,935,721	13	12/31/2022	$10,822,575	$5,619,133	$1,788,968	$2,561,650	$2,151,341
2023	7,897,482	12	12/31/2023	$10,319,978	$5,358,183	$1,705,889	$2,442,688	$2,051,434
2024	7,633,488	11	12/31/2024	$9,817,381	$5,097,232	$1,622,810	$2,323,726	$1,951,526
2025	7,648,933	10	12/31/2025	$9,314,784	$4,836,281	$1,539,730	$2,204,764	$1,851,618
2026	7,259,519	9	12/31/2026	$8,812,187	$4,575,330	$1,456,651	$2,085,801	$1,751,711
2027	7,275,029	8	12/31/2027	$8,309,589	$4,314,379	$1,373,572	$1,966,839	$1,651,803
2028	7,542,890	7	12/31/2028	$7,806,992	$4,053,428	$1,290,493	$1,847,877	$1,551,895
2029	7,471,972	6	12/31/2029	$7,304,395	$3,792,477	$1,207,414	$1,728,914	$1,451,988
2030	7,439,668	5	12/31/2030	$6,801,798	$3,531,527	$1,124,335	$1,609,952	$1,352,080
2031	7,397,816	4	12/31/2031	$6,299,201	$3,270,576	$1,041,256	$1,490,990	$1,252,172
2032	7,425,475	3	12/31/2032	$5,796,604	$3,009,625	$958,177	$1,372,028	$1,152,265
2033	7,455,564	2	12/31/2033	$5,294,007	$2,748,674	$875,097	$1,253,065	$1,052,357
2034	7,438,099	1	12/31/2034	$4,791,410	$2,487,723	$792,018	$1,134,103	$952,450
Total				**$191,321,644**	**$91,889,335**	**$26,967,437**	**$35,458,621**	**$27,228,109**

	Bridger Capital Forecast	Life (years)	Assumed In-Service	2020	2021	2022	2023	2024
2015	90,802,222	20	12/31/2015	—	—	—	—	—
2016	44,787,706	19	12/31/2016	—	—	—	—	—
2017	13,508,618	18	12/31/2017	—	—	—	—	—
2018	18,268,574	17	12/31/2018	—	—	—	—	—
2019	14,439,932	16	12/31/2019	—	—	—	—	—
2020	9,596,002	15	12/31/2020	$1,666,615	—	—	—	—
2021	7,181,971	14	12/31/2021	$1,595,796	$1,279,658	—	—	—
2022	5,935,721	13	12/31/2022	$1,524,977	$1,222,868	$1,088,414	—	—
2023	7,897,482	12	12/31/2023	$1,454,157	$1,166,079	$1,037,869	$1,495,959	—
2024	7,633,488	11	12/31/2024	$1,383,338	$1,109,289	$987,323	$1,423,104	$1,500,581
2025	7,648,933	10	12/31/2025	$1,312,518	$1,052,500	$936,777	$1,350,249	$1,423,759
2026	7,259,519	9	12/31/2026	$1,241,699	$995,710	$886,232	$1,277,393	$1,346,938
2027	7,275,029	8	12/31/2027	$1,170,879	$938,920	$835,686	$1,204,538	$1,270,116
2028	7,542,890	7	12/31/2028	$1,100,060	$882,131	$785,141	$1,131,683	$1,193,294
2029	7,471,972	6	12/31/2029	$1,029,240	$825,341	$734,595	$1,058,827	$1,116,473
2030	7,439,668	5	12/31/2030	$958,421	$768,551	$684,049	$985,972	$1,039,651
2031	7,397,816	4	12/31/2031	$887,602	$711,762	$633,504	$913,117	$962,829
2032	7,425,475	3	12/31/2032	$816,782	$654,972	$582,958	$840,262	$886,008
2033	7,455,564	2	12/31/2033	$745,963	$598,182	$532,412	$767,406	$809,186
2034	7,438,099	1	12/31/2034	$675,143	$541,393	$481,867	$694,551	$732,364
Total				**$12,747,356**	**$10,206,828**	**$13,143,061**	**$12,281,200**	**$11,882,675**

	Bridger Capital Forecast	Life (years)	Assumed In-Service	2025	2026	2027	2028	2029
2015	90,802,222	20	12/31/2015	—	—	—	—	—
2016	44,787,706	19	12/31/2016	—	—	—	—	—
2017	13,508,618	18	12/31/2017	—	—	—	—	—
2018	18,268,574	17	12/31/2018	—	—	—	—	—
2019	14,439,932	16	12/31/2019	—	—	—	—	—
2020	9,596,002	15	12/31/2020	—	—	—	—	—
2021	7,181,971	14	12/31/2021	—	—	—	—	—
2022	5,935,721	13	12/31/2022	—	—	—	—	—
2023	7,897,482	12	12/31/2023	—	—	—	—	—
2024	7,633,488	11	12/31/2024	—	—	—	—	—
2025	7,648,933	10	12/31/2025	$1,569,304	—	—	—	—
2026	7,259,519	9	12/31/2026	$1,484,629	$1,565,606	—	—	—
2027	7,275,029	8	12/31/2027	$1,399,955	$1,476,313	$1,664,400	—	—
2028	7,542,890	7	12/31/2028	$1,315,280	$1,387,020	$1,563,731	$1,852,921	—
2029	7,471,972	6	12/31/2029	$1,230,605	$1,297,726	$1,463,061	$1,733,634	$2,003,557
2030	7,439,668	5	12/31/2030	$1,145,930	$1,208,433	$1,362,392	$1,614,347	$1,865,697
2031	7,397,816	4	12/31/2031	$1,061,255	$1,119,140	$1,261,722	$1,495,060	$1,727,838
2032	7,425,475	3	12/31/2032	$976,580	$1,029,846	$1,161,053	$1,375,773	$1,589,978
2033	7,455,564	2	12/31/2033	$891,906	$940,553	$1,060,383	$1,256,486	$1,452,118
2034	7,438,099	1	12/31/2034	$807,231	$851,260	$959,713	$1,137,199	$1,314,259
Total				**$11,882,675**	**$10,875,898**	**$10,496,455**	**$10,465,423**	**$9,953,447**

	Bridger Capital Forecast	Life (years)	Assumed In-Service	2030	2031	2032	2033	2034
2015	90,802,222	20	12/31/2015	—	—	—	—	—
2016	44,787,706	19	12/31/2016	—	—	—	—	—
2017	13,508,618	18	12/31/2017	—	—	—	—	—
2018	18,268,574	17	12/31/2018	—	—	—	—	—
2019	14,439,932	16	12/31/2019	—	—	—	—	—
2020	9,596,002	15	12/31/2020	—	—	—	—	—
2021	7,181,971	14	12/31/2021	—	—	—	—	—
2022	5,935,721	13	12/31/2022	—	—	—	—	—
2023	7,897,482	12	12/31/2023	—	—	—	—	—
2024	7,633,488	11	12/31/2024	—	—	—	—	—
2025	7,648,933	10	12/31/2025	—	—	—	—	—
2026	7,259,519	9	12/31/2026	—	—	—	—	—
2027	7,275,029	8	12/31/2027	—	—	—	—	—
2028	7,542,890	7	12/31/2028	—	—	—	—	—
2029	7,471,972	6	12/31/2029	—	—	—	—	—
2030	7,439,668	5	12/31/2030	$2,229,158	—	—	—	—
2031	7,397,816	4	12/31/2031	$2,064,441	$2,566,035	—	—	—
2032	7,425,475	3	12/31/2032	$1,899,725	$2,361,297	$3,160,168	—	—
2033	7,455,564	2	12/31/2033	$1,735,008	$2,156,560	$2,886,164	$4,346,789	—
2034	7,438,099	1	12/31/2034	$1,570,292	$1,951,823	$2,612,160	$3,934,118	$7,849,803
Total				**$9,498,625**	**$9,035,714**	**$8,658,492**	**$8,280,906**	**$7,849,803**

Revenue Requirement on Decommissioning Costs

	Decommissioning Costs (Estimated in 2034 dollars)
2034 Costs	$52,244,513
Present Value	$29,794,316
Annual Payment	$1,241,717

Total Payments—Comparison between Option 1 & 2

	Option 1	Option 2			
Year	Continue w/SCR	Total Payments Accelerated Shutdown*	Costs of Replacement CCCT	Total Annual Costs	Difference between Option 1 & 2
2015	$116,599,549	$335,842,318	$169,233,797	$505,076,115	$388,476,567
2016	$123,456,396	$351,737,422	$159,080,882	$510,818,304	$387,361,908
2017	$125,965,668		$158,051,633	$158,051,633	$32,085,964
2018	$128,855,226		$164,658,910	$164,658,910	$35,803,683
2019	$130,549,824		$170,473,692	$170,473,692	$39,923,868
2020	$122,022,445		$172,507,122	$172,507,122	$50,484,678
2021	$119,373,933		$174,789,729	$174,789,729	$55,415,797
2022	$119,534,731		$175,912,781	$175,912,781	$56,378,050
2023	$122,343,322		$179,087,087	$179,087,087	$56,743,766
2024	$135,574,982		$181,551,652	$181,551,652	$45,976,670
2025	$136,754,850		$183,671,759	$183,671,759	$46,916,909
2026	$138,468,578		$181,060,725	$181,060,725	$42,592,147
2027	$140,232,087		$181,088,595	$181,088,595	$40,856,508
2028	$142,152,387		$183,931,004	$183,931,004	$41,778,617
2029	$144,044,717		$188,184,330	$188,184,330	$44,139,613
2030	$146,101,790		$195,077,058	$195,077,058	$48,975,268
2031	$148,487,168		$201,099,893	$201,099,893	$52,612,724
2032	$151,325,114		$203,445,436	$203,445,436	$52,120,322
2033	$155,141,012		$209,308,283	$209,308,283	$54,167,271
2034	$162,120,005		$58,279,478**	$58,279,478	$(103,840,527)
NPV	**$1,419,569,231**			**$2,495,855,049**	**$1,076,285,818**

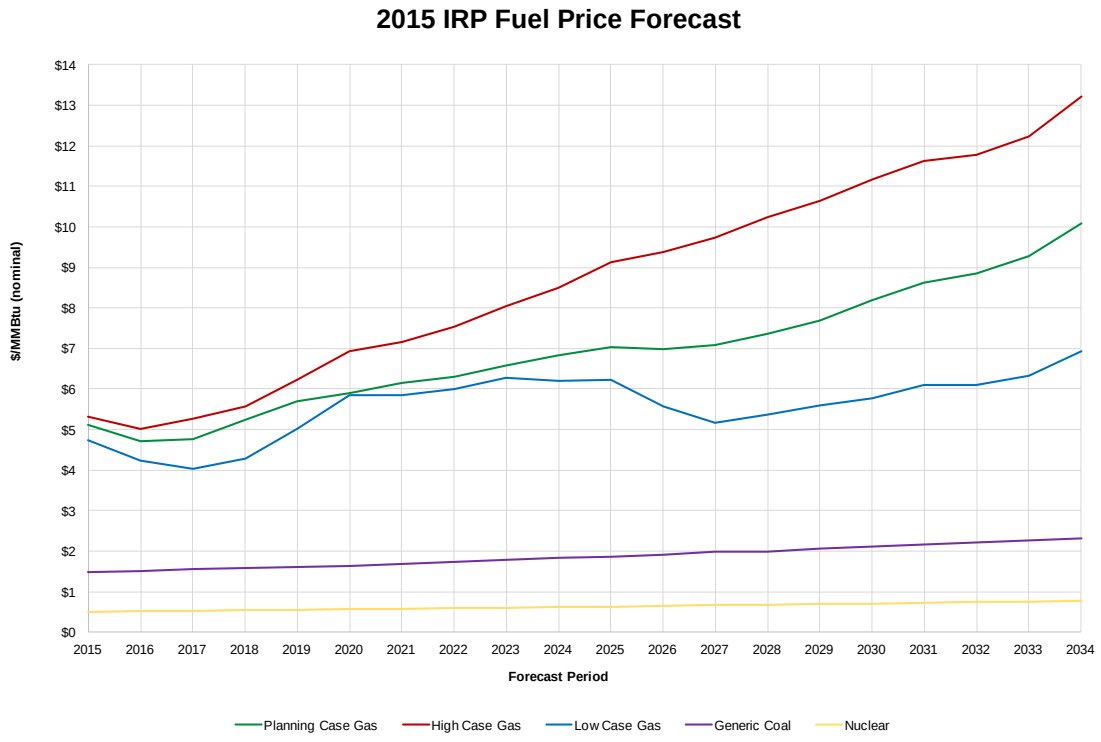
*Bridger SCR 3 and 4 Stacked PWorth—accelerated

**Residual value (Book value) included in the final year: (163,567,666)

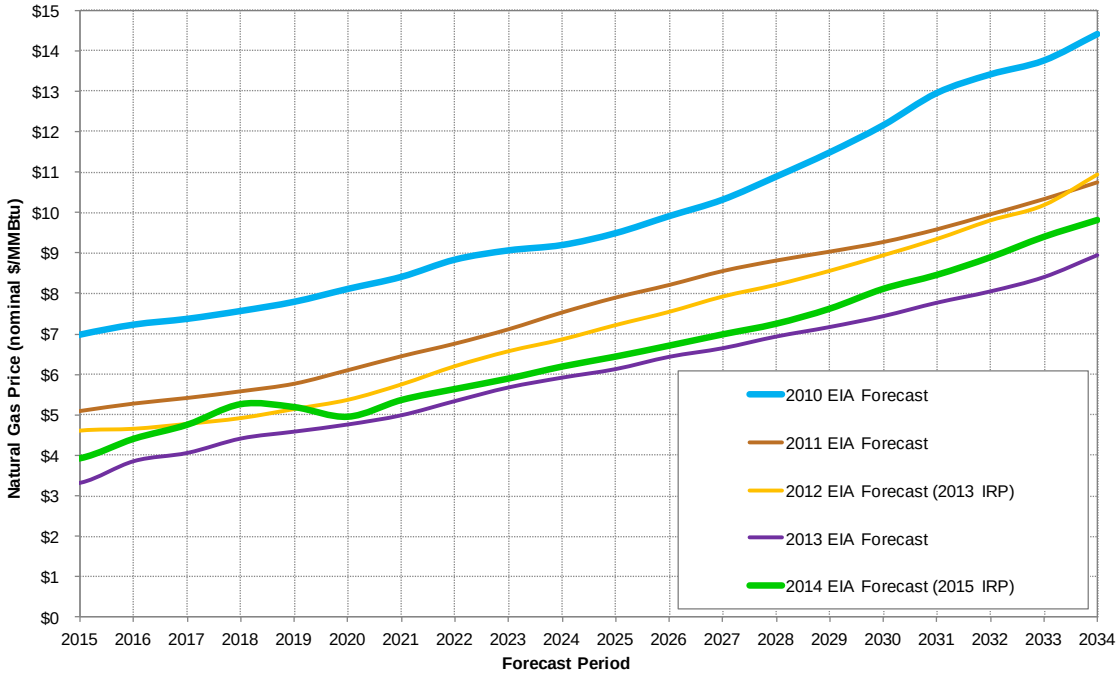
FUEL PRICE FORECAST

Natural Gas and Coal Price Forecast (nominal $/MMBtu)

	Idaho Citygate Natural Gas				
Year	Planning Case	High Case	Low Case	Generic Coal	Nuclear
2015	$5.10	$5.32	$4.74	$1.47	$0.51
2016	$4.70	$5.02	$4.24	$1.52	$0.52
2017	$4.76	$5.26	$4.02	$1.55	$0.53
2018	$5.25	$5.56	$4.27	$1.58	$0.54
2019	$5.69	$6.22	$5.02	$1.61	$0.56
2020	$5.91	$6.94	$5.85	$1.64	$0.57
2021	$6.14	$7.17	$5.85	$1.69	$0.58
2022	$6.30	$7.54	$5.99	$1.74	$0.59
2023	$6.58	$8.04	$6.27	$1.78	$0.61
2024	$6.82	$8.49	$6.21	$1.83	$0.62
2025	$7.04	$9.13	$6.24	$1.87	$0.63
2026	$6.99	$9.38	$5.57	$1.91	$0.65
2027	$7.09	$9.73	$5.17	$1.98	$0.66
2028	$7.35	$10.24	$5.38	$2.00	$0.68
2029	$7.69	$10.64	$5.60	$2.07	$0.69
2030	$8.18	$11.18	$5.77	$2.12	$0.71
2031	$8.62	$11.62	$6.10	$2.16	$0.72
2032	$8.85	$11.78	$6.09	$2.21	$0.74
2033	$9.28	$12.24	$6.33	$2.27	$0.75
2034	$10.09	$13.21	$6.94	$2.32	$0.77



Historical EIA Henry Hub Spot Price Forecasts



*all values taken from EIA Annual Energy Outlook reports:
http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=0-AEO2013&table=13-AEO2013&region=0-0&cases=ref2013-d102312a

EXISTING RESOURCE DATA

Hydroelectric and Thermal Plant Data

Hydroelectric Power Plans	Nameplate kVA	Nameplate kW	Normal Rating kW[4]	Emergency Rating kW[5]
American Falls	102,600	92,340	92,340	106,190
Bliss	86,250	75,000	75,000	84,860
Brownlee	650,444	585,400	585,400	678,040
Cascade	13,800	12,420	12,420	14,280
C.J. Strike	90,000	82,800	82,800	95,420
Clear Lake	3,125	2,500[1]	2,420	2,430
Hells Canyon	435,000	391,500	391,500	449,580
Lower Salmon	70,000	60,000	60,000	69,140
Malad–Lower	15,500	13,500	13,500	13,500
Malad–Upper	9,650	8,270	8,270	8,400
Milner	62,890	59,448	59,448	61,880
Oxbow	211,112	190,000	190,000	218,520
Shoshone Falls	14,900	12,500[1]	12,500	12,500
Swan Falls	28,600	27,170	24,170[3]	24,170
Thousand Springs	11,000	8,800	6,380[2]	6,380
Twin Falls	56,175	52,897	52,561	54,170
Upper Salmon “A”	18,000	18,000	18,000	18,000
Upper Salmon “B”	18,000	16,500	16,500	16,560
Total Hydro	**1,897,046**	**1,709,045**		

Thermal, Natural Gas, and Diesel Power Plans	Generator Nameplate Rating Gross kVA	Generator Nameplate Rating Gross kW	Net Dependable Capability (NDC)[6,7] kW	Net Dependable Capability (NDC)[6,7] Summer kW	Net Dependable Capability (NDC)[6,7] Winter kW
Bridger (Idaho Power share)	811,053	770,501		707,667	707,667
Boardman (Idaho Power share)	67,600	64,200		57,550	58,050
Valmy (Idaho Power share)	315,000	283,500		260,000	260,000
Total Thermal	**1,193,653**	**1,118,201**			
Bennett Mountain	192,000	172,800	164,159		
Evander Andrews Unit #1	199,000	179,100	170,955		
Evander Andrews Unit #2	51,000	45,900	45,405		
Evander Andrews Unit #3	51,000	45,900	45,066		
Langley Gulch CT	220,000	187,000	176,880		
Langley Gulch ST	154,650	131,452	122,765		
Total Natural Gas	**867,650**	**762,152**			
Salmon Diesel	6,880	5,000	5,500		
Total IPC Generation	**3,965,229**	**3,594,398**			

1 A power factor rating of 0.8 is assumed on four units (Clear Lake, Shoshone Falls unit 2, and Thousand Springs units 1 and 2) with a total kVA rating of 6,127 kVA where there is no nameplate kW rating.

2 The two smaller units, 1 and 2, have nameplate ratings of 1.25 MVA and 1 MW and are not in service due to reduced flows from the springs and penstock integrity.

3 The Swan Falls units have been limited to 24,170 kW as a result of vibration issues.

4 Normal Rating is the normal kW output of the facility with all units on-line. This rating includes all equipment limitations and may be lower than the nameplate rating. To operate at the Normal Rating, appropriate water conditions must exist and the FERC license requirements permit.

5 Emergency Rating is the maximum kW output of the facility with all units on-line. The Emergency Rating is based on manufacturer guidelines, ANSI standards, and limited by auxiliary equipment ratings. To operate at the Emergency Rating, appropriate water conditions must exist and the FERC license requirements permit.

6 Ratings for coal-fired generators are provided by Idaho Power's thermal partners who operate these plants.

7 NDC is defined in the NERC Generating Availability Data System (GADS) as Gross Dependable Capacity (GDC) less the unit capacity utilized for that unit's station service or auxiliaries. GDC is the Gross Maximum Capacity (GMC) modified for seasonal limitations over a specified period of time. The GDC and Maximum Dependable Capacity (MDC) used in previous GADS reports are the same in intent and purpose. GMC is the maximum capacity a unit can sustain over a specified period of time when not restricted by seasonal or other de-ratings.

Qualifying Facility Data (PURPA)

Cogeneration and Small Power Production Projects

Status as of May 26, 2015.

Project	MW	Contract On-line Date	Contract End Date	Project	MW	Contract On-line Date	Contract End Date
Hydro Projects							
Arena Drop	0.45	Sep-2010	Sep-2030	Little Wood Rvr Res	2.85	Feb-1985	Feb-2020
Barber Dam	3.70	Apr-1989	Apr-2024	Littlewood / Arkoosh	0.87	Aug-1986	Aug-2021
Birch Creek	0.05	Nov-1984	Nov-2019	Low Line Canal	7.97	May-1985	May-2020
Black Canyon #3	0.14	Apr-1984	Apr-2019	Low Line Midway Hydro	2.50	Aug-2007	Aug-2027
Black Canyon Bliss Hydro	0.03	Nov-2014	Estimated	Lowline #2	2.79	Apr-1988	Apr-2023
Blind Canyon	1.63	Dec-2014	Dec-2034	Magic Reservoir	9.07	Jun-1989	Jun-2024
Box Canyon	0.36	Feb-1984	Feb-2019	Malad River	0.62	May-1984	May-2019
Briggs Creek	0.60	Oct-1985	Oct-2020	Marco Ranches	1.20	Aug-1985	Aug-2020
Bypass	9.96	Jun-1988	Jun-2023	Mile 28	1.50	Jun-1994	Jun-2029
Canyon Springs	0.13	Oct-1984	Oct-2040	Mill Creek Hydroelectric	0.80	Oct-2011	Jun-2017
Cedar Draw	1.55	Jun-1984	Jun-2019	Mitchell Butte	2.09	May-1989	Dec-2033
Clark Canyon Hydroelectric	7.55	Jun-2017	Estimated	Mora Drop Small Hydro Fac	1.85	Sep-2006	Sep-2026
Clear Springs Trout	0.52	Nov-1983	Nov-2018	Mud Creek/S&S	0.52	Feb-1982	Jan-2017
Crystal Springs	2.44	Apr-1986	Apr-2021	Mud Creek/White	0.21	Jan-1986	Jan-2021
Curry Cattle Company	0.22	Jun-1983	Jun-2018	Owyhee Dam Cspp	5.00	Aug-1985	May-2033
Dietrich Drop	4.50	Aug-1988	Aug-2023	Pigeon Cove	1.89	Oct-1984	Oct-2019
Eightmile Hydro Project	0.36	Oct-2014	Oct-2034	Pristine Springs #1 2005	0.13	May-2005	May-2015
Elk Creek	2.00	May-1986	May-2021	Pristine Springs #3 2005	0.20	May-2005	May-2015
Falls River	9.10	Aug-1993	Aug-2028	Reynolds Irrigation	0.26	May-1986	May-2021
Fargo Drop Hydroelectric	1.27	Apr-2013	Apr-2033	Rock Creek #1	2.05	Sep-1983	Sep-2018
Faulkner Ranch	0.87	Aug-1987	Aug-2022	Rock Creek #2	1.90	Apr-1989	Apr-2024
Fisheries Dev.	0.26	Jul-1990	Jul-2040	Sagebrush	0.43	Sep-1985	Sep-2020
Geo-Bon #2	0.93	Nov-1986	Nov-2021	Sahko Hydro	0.50	Feb-2011	Feb-2021
Hailey Cspp	0.06	Jun-1985	Jun-2020	Schaffner	0.53	Aug-1986	Aug-2021
Hazelton A	8.10	Mar-2011	Mar-2026	Shingle Creek	0.22	Aug-1983	Aug-2017
Hazelton B	7.60	May-1993	May-2028	Shoshone #2	0.58	May-1996	May-2031
Head of U Canal Project	1.28	May-2015	Estimated	Shoshone Cspp	0.37	Jun-1982	Feb-2017
Horseshoe Bend Hydro	9.50	Sep-1995	Sep-2030	Snake River Pottery	0.07	Nov-1984	Nov-2019
Jim Knight	0.34	Jun-1985	Jun-2020	Snedigar	0.54	Jan-1985	Jan-2020
Kasel & Witherspoon	0.90	Mar-1984	Mar-2019	Tiber Dam	7.50	Jun-2004	Jun-2024
Koyle Small Hydro	1.25	Apr-1984	Apr-2019	Trout-Co	0.24	Dec-1986	Dec-2021
Lateral # 10	2.06	May-1985	May-2020	Tunnel #1	7.00	Jun-1993	Feb-2035
Lemoyne	0.08	Jun-1985	Jun-2020	White Water Ranch	0.16	Aug-1985	Aug-2020
Little Wood River Ranch II	1.25	Jun-2015	Estimated	Wilson Lake Hydro	8.40	May-1993	May-2028
Total Hydro Nameplate Rating 153.81 MW							
Thermal Projects							
Magic Valley Natural Gas	10.00	Nov-1996	Nov-2016	TASCO—Nampa Natural Gas	2.00	Sep-2003	Non firm
Simplot Pocatello Cogen	15.90	Mar-2013	Feb-2016	TASCO—Twin Falls Natural Gas	3.00	Aug-2001	Non firm
Total Thermal Nameplate Rating 30.90 MW							

Project	MW	Contract On-line Date	Contract End Date	Project	MW	Contract On-line Date	Contract End Date
Biomass Projects							
B6 Anaerobic Digester	2.28	Aug-2010	Aug-2020	Fighting Creek Landfill	3.06	Apr-2014	Apr-2029
Bannock County Landfill	3.20	May-2014	May-2034	Hidden Hollow Landfill Gas	3.20	Jan-2007	Jan-2027
Bettencourt Dry Creek BioFactory	2.25	May-2010	May-2020	Pocatello Waste	0.46	Dec-1985	Dec-2020
Big Sky West Dairy Digester	1.50	Jan-2009	Jan-2029	Rock Creek Dairy	4.00	Aug-2012	Aug-2027
Double A Digester Project	4.50	Jan-2012	Jan-2032	Tamarack CSPP	5.00	Jun-1983	Jun-2018
Total Biomass Nameplate Rating 29.45 MW							
Solar Projects							
American Falls Solar II, LLC	20.00	Dec-2016	Estimated	Open Range Solar Center, LLC	10.00	Dec-2016	Estimated
American Falls Solar, LLC	40.00	Jan-2016	Estimated	Orchard Ranch Solar, LLC	20.00	Dec-2016	Estimated
Boise City Solar, LLC	80.00	Sep-2016	Estimated	Pocatello Solar 1, LLC	20.00	Dec-2016	Estimated
Grand View PV Solar Two	10.00	Dec-2016	Estimated	Railroad Solar Center, LLC	10.00	Dec-2016	Estimated
Grove Solar Center, LLC	10.00	Dec-2016	Estimated	Simco Solar, LLC	20.00	Dec-2016	Estimated
Hyline Solar Center, LLC	20.00	Dec-2016	Estimated	Thunderegg Solar Center, LLC	10.00	Dec-2016	Estimated
Mountain Home Solar, LLC	20.00	Dec-2016	Estimated	Vale Air Solar Center, LLC	10.00	Dec-2016	Estimated
Murphy Flat Power, LLC	20.00	Dec-2016	Estimated				
Total Solar Nameplate Rating 320 MW							
Wind Projects							
Bennett Creek Wind Farm	21.00	Dec-2008	Dec-2028	Mainline Windfarm	23.00	Dec-2012	Dec-2032
Benson Creek Windfarm	10.00	Dec-2016	Estimated	Milner Dam Wind	19.92	Feb-2011	Feb-2031
Burley Butte Wind Park	21.30	Feb-2011	Feb-2031	Oregon Trail Wind Park	13.50	Jan-2011	Jan-2031
Camp Reed Wind Park	22.50	Dec-2010	Dec-2030	Payne's Ferry Wind Park	21.00	Dec-2010	Dec-2030
Cassia Wind Farm LLC	10.50	Mar-2009	Mar-2029	Pilgrim Stage Station Wind Park	10.50	Jan-2011	Jan-2031
Cold Springs Windfarm	23.00	Dec-2012	Dec-2032	Prospector Windfarm	10.00	Dec-2016	Estimated
Desert Meadow Windfarm	23.00	Dec-2012	Dec-2032	Rockland Wind Farm	80.00	Dec-2011	Dec-2036
Durbin Creek Windfarm	10.00	Dec-2016	Estimated	Ryegrass Windfarm	23.00	Dec-2012	Dec-2032
Fossil Gulch Wind	10.50	Sep-2005	Sep-2025	Salmon Falls Wind	22.00	Apr-2011	Apr-2031
Golden Valley Wind Park	12.00	Feb-2011	Feb-2031	Sawtooth Wind Project	22.00	Nov-2011	Nov-2031
Hammett Hill Windfarm	23.00	Dec-2012	Dec-2032	Thousand Springs Wind Park	12.00	Jan-2011	Jan-2031
High Mesa Wind Project	40.00	Dec-2012	Dec-2032	Tuana Gulch Wind Park	10.50	Jan-2011	Jan-2031
Horseshoe Bend Wind	9.00	Feb-2006	Feb-2026	Tuana Springs Expansion	35.70	May-2010	May-2030
Hot Springs Wind Farm	21.00	Dec-2008	Dec-2028	Two Ponds Windfarm	23.00	Dec-2012	Dec-2032
Jett Creek Windfarm	10.00	Dec-2016	Estimated	Willow Spring Windfarm	10.00	Dec-2016	Estimated
Lime Wind Energy	3.00	Dec-2011	Dec-2031	Yahoo Creek Wind Park	21.00	Dec-2010	Dec-2030
Total Wind Nameplate Rating 626.92 MW							
Total Nameplate Rating 1,161.80 MW							

The above is a summary of the Nameplate rating for the CSPP projects under contract with Idaho Power as of May 26, 2015. In the case of CSPP projects, Nameplate rating of the actual generation units is not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy these projects will produce.

Power Purchase Agreement Data

Idaho Power Company Power Purchase Agreements Status as of April 1, 2015

Project	MW	Contract On-Line Date	Contract End Date
Wind projects			
Elkhorn Wind Project	101	December 2007	December 2027
Total wind nameplate MW rating	101		
Geothermal Projects			
Raft River Unit 1	13	April 2008	April 2033
Neal Hot Springs	22	November 2012	November 2037
Total geothermal nameplate MW rating	35		
Total nameplate MW rating	136		

1. Above is a summary of the nameplate ratings for the Power Purchase Agreements under contract with Idaho Power. Nameplate ratings of the actual generation units are not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource-specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy the projects will produce.
2. Not included in the above table is the energy exchange agreement between Idaho Power and the Clatskanie PUD. Under the exchange, Idaho Power receives energy from the 18-MW power plant at Arrowrock Dam on the Boise River and returns to Clatskanie PUD energy of an equivalent value delivered seasonally. The agreement began in January 2010 and extends through 2015. Idaho Power retains the right to renew the agreement through 2025.

Hydro Modeling Results (PDR580)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2015**	**2/2015**	**3/2015**	**4/2015**	**5/2015**	**6/2015**	**7/2015**	**8/2015**	**9/2015**	**10/2015**	**11/2015**	**12/2015**	**aMW**
Brownlee	HCC*	319.5	359.7	341.3	433.4	409.9	397.5	247.5	164.8	212.9	193.7	152.6	253.6	290.5
Oxbow	HCC	131.7	155.5	155.1	188.7	168.0	161.7	105.0	75.3	97.5	89.0	69.3	106.8	125.3
Hells Canyon	HCC	259.2	308.6	313.1	386.6	346.5	326.9	208.1	148.1	191.3	175.5	138.1	211.7	251.1
1000 Springs	ROR**	24.4	25.8	26.0	58.3	83.0	89.5	83.9	64.8	43.1	16.1	-	17.4	44.4
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	49.5	50.4	44.0	54.2	48.2	42.0	35.3	28.3	37.3	40.0	38.4	45.8	42.8
C .J. Strike	ROR	64.7	66.1	58.9	70.6	60.8	52.2	36.9	31.4	44.6	51.0	50.7	59.9	54.0
Cascade	ROR	1.5	1.5	2.8	5.9	5.5	11.7	10.3	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	34.9	35.5	29.3	38.4	34.2	28.3	23.0	16.1	23.6	26.0	24.3	31.5	28.8
Milner	ROR	41.5	42.1	26.3	42.5	34.3	15.4	6.2	-	-	-	4.9	30.8	20.3
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	20.9	21.3	19.0	22.6	19.9	17.1	12.9	11.0	15.0	16.9	16.8	19.4	17.7
Twin Falls	ROR	40.8	41.8	27.9	45.8	34.7	20.1	10.5	-	-	6.6	9.1	31.6	22.4
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.1	19.1	19.1	19.1	17.6	18.1	14.1	8.9	14.5	16.1	14.9	19.2	16.7
Upper Salmon 3&4	ROR	17.7	17.7	17.6	17.7	17.7	16.2	13.2	8.9	13.6	15.0	13.9	17.7	15.6
HCC Total		**710.4**	**823.8**	**809.5**	**1,008.7**	**924.3**	**886.1**	**560.6**	**388.2**	**501.7**	**458.2**	**360.0**	**572.1**	**667.0**
ROR Total		**353.1**	**360.4**	**310.6**	**414.6**	**396.6**	**349.8**	**285.2**	**217.2**	**235.8**	**228.4**	**212.9**	**313.1**	**306.5**
Total		**1,063.5**	**1,184.2**	**1,120.1**	**1,423.3**	**1,320.9**	**1,235.9**	**845.8**	**605.4**	**737.5**	**686.6**	**572.9**	**885.2**	**973.4**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2016**	**2/2016**	**3/2016**	**4/2016**	**5/2016**	**6/2016**	**7/2016**	**8/2016**	**9/2016**	**10/2016**	**11/2016**	**12/2016**	**aMW**
Brownlee	HCC*	319.9	361.6	342.8	440.7	419.2	406.5	247.9	164.5	212.8	193.5	152.7	254.7	293.1
Oxbow	HCC	131.9	156.3	155.7	191.7	171.7	165.2	105.2	75.2	97.5	88.9	69.4	107.3	126.3
Hells Canyon	HCC	259.5	310.1	314.4	392.7	353.8	333.8	208.5	147.8	191.4	175.4	138.2	212.6	253.2
1000 Springs	ROR**	24.8	26.5	26.8	60.7	84.5	90.9	83.9	64.9	42.8	16.1	-	19.3	45.1
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	49.4	50.5	44.2	55.0	49.1	42.3	35.2	28.2	37.2	40.0	38.0	47.3	43.0
C .J. Strike	ROR	64.6	66.1	59.6	70.7	63.4	53.4	36.7	31.3	44.5	51.0	50.6	60.7	54.4
Cascade	ROR	1.5	1.5	2.8	5.9	5.5	11.7	10.3	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	34.9	35.7	29.7	38.9	35.0	28.9	23.0	16.0	23.5	25.9	24.3	32.5	29.0
Milner	ROR	42.0	43.0	26.9	42.5	36.7	17.3	6.2	-	-	-	4.9	34.6	21.2
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	20.9	21.3	19.3	22.8	20.4	17.5	12.9	11.0	14.9	16.8	16.7	19.6	17.8
Twin Falls	ROR	41.7	42.1	28.0	45.8	36.7	21.3	10.5	-	-	6.6	9.1	35.4	23.1
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.1	19.1	19.2	19.1	17.6	18.6	14.0	8.9	14.4	16.1	14.8	19.2	16.7
Upper Salmon 3&4	ROR	17.7	17.7	17.7	17.7	17.7	16.2	13.2	8.8	13.5	15.0	13.9	17.7	15.6
HCC Total		**711.3**	**828.0**	**812.9**	**1,025.1**	**944.7**	**905.5**	**561.6**	**387.5**	**501.6**	**457.8**	**360.3**	**574.6**	**672.6**
ROR Total		**354.7**	**362.6**	**313.9**	**418.6**	**407.3**	**357.3**	**284.8**	**216.9**	**235.0**	**228.2**	**212.2**	**326.1**	**309.8**
Total		**1,066.0**	**1,190.6**	**1,126.8**	**1,443.7**	**1,351.9**	**1,262.8**	**846.4**	**604.4**	**736.6**	**686.0**	**572.5**	**900.7**	**982.4**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2017**	**2/2017**	**3/2017**	**4/2017**	**5/2017**	**6/2017**	**7/2017**	**8/2017**	**9/2017**	**10/2017**	**11/2017**	**12/2017**	**aMW**
Brownlee	HCC*	319.1	365.2	343.4	446.8	429.4	418.8	248.5	164.6	210.7	194.5	152.6	253.7	295.6
Oxbow	HCC	131.6	157.8	156.0	194.3	175.8	170.1	105.4	75.2	96.3	89.1	69.2	106.9	127.3
Hells Canyon	HCC	258.9	313.1	314.9	397.8	361.8	343.3	209.0	148.0	189.1	175.7	138.0	211.8	255.1
1000 Springs	ROR**	25.1	26.6	27.1	61.1	85.8	93.3	84.0	65.0	43.1	16.6	-	20.9	45.7
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	49.2	50.6	44.2	55.4	50.2	43.6	35.4	28.3	37.2	40.0	38.1	48.2	43.4
C .J. Strike	ROR	64.8	66.0	59.4	70.7	65.1	53.7	36.8	31.5	44.5	51.1	50.1	61.7	54.6
Cascade	ROR	1.5	1.5	2.8	5.9	5.5	11.7	10.3	13.3	8.8	1.9	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	35.0	35.4	29.6	38.9	35.9	29.3	23.0	16.1	23.4	26.0	23.9	33.0	29.1
Milner	ROR	41.5	42.3	27.8	42.9	39.0	20.9	6.2	-	-	-	3.8	34.8	21.6
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	20.9	21.3	19.3	22.7	21.1	17.5	12.9	11.0	14.9	16.8	16.4	19.9	17.9
Twin Falls	ROR	41.5	41.6	29.1	45.8	38.7	23.8	10.5	-	-	6.6	8.5	35.1	23.4
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.1	19.1	19.2	19.1	17.6	19.0	14.0	8.9	14.3	16.1	14.5	19.2	16.7
Upper Salmon 3&4	ROR	17.7	17.7	17.7	17.7	17.7	16.2	13.2	8.8	13.4	15.0	13.6	17.7	15.5
HCC Total		**709.6**	**836.1**	**814.3**	**1,038.9**	**967.0**	**932.2**	**562.9**	**387.8**	**496.1**	**459.3**	**359.8**	**572.4**	**678.0**
ROR Total		**354.4**	**361.2**	**315.9**	**419.7**	**417.3**	**368.2**	**285.2**	**217.4**	**234.9**	**228.9**	**208.8**	**330.3**	**311.9**
Total		**1,064.0**	**1,197.3**	**1,130.2**	**1,458.6**	**1,384.3**	**1,300.4**	**848.1**	**605.2**	**731.0**	**688.2**	**568.6**	**902.7**	**989.9**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2018**	**2/2018**	**3/2018**	**4/2018**	**5/2018**	**6/2018**	**7/2018**	**8/2018**	**9/2018**	**10/2018**	**11/2018**	**12/2018**	**aMW**
Brownlee	HCC*	321.3	364.6	343.3	444.7	432.7	419.1	249.0	164.3	209.5	194.4	153.1	252.6	295.7
Oxbow	HCC	132.5	157.5	155.9	193.4	176.8	170.2	105.6	75.1	95.7	88.9	69.4	106.4	127.3
Hells Canyon	HCC	260.5	312.6	314.8	396.0	364.4	343.5	209.4	147.7	187.8	175.5	138.3	210.9	255.1
1000 Springs	ROR**	25.7	28.4	27.0	61.3	86.8	95.1	84.0	65.1	43.1	17.8	-	20.9	46.3
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	49.5	51.1	43.7	55.4	50.9	44.7	35.3	28.2	37.0	40.0	38.0	47.3	43.4
C .J. Strike	ROR	65.4	66.4	58.9	70.7	66.1	54.6	36.7	31.4	44.3	51.0	50.1	61.3	54.7
Cascade	ROR	1.5	1.6	2.8	5.9	5.3	12.0	10.2	13.3	8.8	2.0	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	35.1	36.2	29.2	38.9	36.6	30.2	22.9	16.0	23.3	25.9	23.8	32.7	29.2
Milner	ROR	41.5	45.0	26.7	44.9	40.9	24.5	6.2	-	-	-	3.6	34.3	22.3
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	12.0	12.0	11.0
Swan Falls	ROR	20.9	21.4	19.1	22.7	21.3	17.8	12.8	11.0	14.9	16.8	16.4	19.8	17.9
Twin Falls	ROR	41.6	43.8	28.3	47.4	40.5	26.9	10.5	-	-	6.6	8.5	34.7	24.1
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.1	19.1	19.1	19.1	17.5	19.2	14.0	8.8	14.2	16.0	14.4	19.2	16.6
Upper Salmon 3&4	ROR	17.7	17.7	17.5	17.7	17.7	16.2	13.2	8.8	13.3	14.9	13.5	17.7	15.5
HCC Total		**714.3**	**834.7**	**814.0**	**1,034.1**	**973.9**	**932.8**	**564.0**	**387.1**	**493.0**	**458.8**	**360.8**	**569.9**	**678.1**
ROR Total		**356.1**	**369.8**	**312.0**	**423.5**	**424.3**	**380.4**	**284.7**	**217.1**	**234.2**	**229.8**	**208.2**	**327.7**	**314.0**
Total		**1,070.4**	**1,204.5**	**1,126.0**	**1,457.6**	**1,398.1**	**1,313.2**	**848.7**	**604.2**	**727.2**	**688.6**	**569.0**	**897.6**	**992.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2019**	**2/2019**	**3/2019**	**4/2019**	**5/2019**	**6/2019**	**7/2019**	**8/2019**	**9/2019**	**10/2019**	**11/2019**	**12/2019**	**aMW**
Brownlee	HCC*	320.0	363.3	344.2	441.7	437.9	419.7	249.6	164.8	207.5	195.1	153.1	250.3	295.6
Oxbow	HCC	132.0	157.0	156.3	192.2	177.8	170.4	105.9	75.3	94.5	89.0	69.3	105.4	127.1
Hells Canyon	HCC	259.6	311.5	315.6	393.5	368.5	344.0	209.9	148.1	185.6	175.5	138.1	208.9	254.9
1000 Springs	ROR**	25.9	28.4	27.2	61.0	87.9	95.5	84.1	65.1	43.1	18.2	5.2	18.1	46.6
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	49.7	51.4	42.4	54.5	51.5	45.5	35.5	28.4	37.1	40.1	37.2	46.1	43.3
C .J. Strike	ROR	65.8	67.4	57.6	70.1	67.0	55.2	36.8	31.5	44.3	51.1	48.8	58.4	54.5
Cascade	ROR	1.5	1.6	2.8	5.9	5.3	12.0	10.2	13.3	8.8	2.0	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	35.3	36.6	28.2	38.9	37.4	31.7	23.0	16.1	23.3	25.9	23.4	30.5	29.2
Milner	ROR	41.7	44.9	22.6	43.7	42.7	27.2	6.2	-	-	-	-	27.8	21.4
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	9.7	12.0	10.8
Swan Falls	ROR	21.0	21.5	18.7	22.5	21.6	18.0	12.9	11.1	14.9	16.9	16.1	19.0	17.9
Twin Falls	ROR	41.8	43.7	24.7	46.7	41.9	28.9	10.5	-	-	6.6	6.0	28.9	23.3
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.1	19.1	18.3	19.1	17.5	19.2	14.1	8.9	14.2	16.1	14.1	19.2	16.6
Upper Salmon 3&4	ROR	17.7	17.7	16.9	17.7	17.7	16.2	13.2	8.8	13.3	15.0	13.3	17.7	15.4
HCC Total		**711.6**	**831.8**	**816.1**	**1,027.4**	**984.2**	**934.1**	**565.4**	**388.2**	**487.6**	**459.6**	**360.5**	**564.6**	**677.6**
ROR Total		**357.6**	**371.4**	**299.1**	**419.6**	**431.2**	**388.6**	**285.4**	**217.7**	**234.3**	**230.7**	**201.7**	**305.5**	**311.9**
Total		**1,069.2**	**1,203.2**	**1,115.2**	**1,447.0**	**1,415.4**	**1,322.7**	**850.8**	**605.9**	**721.9**	**690.3**	**562.2**	**870.1**	**989.5**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2020**	**2/2020**	**3/2020**	**4/2020**	**5/2020**	**6/2020**	**7/2020**	**8/2020**	**9/2020**	**10/2020**	**11/2020**	**12/2020**	**aMW**
Brownlee	HCC*	318.8	360.6	343.8	440.8	436.3	418.9	249.0	164.1	205.9	195.3	153.5	249.2	294.7
Oxbow	HCC	131.5	155.8	156.2	191.8	177.4	170.1	105.6	75.0	93.7	89.0	69.4	104.9	126.7
Hells Canyon	HCC	258.6	309.3	315.3	392.8	367.2	343.3	209.4	147.5	184.0	175.5	138.3	208.0	254.1
1000 Springs	ROR**	25.7	27.1	26.9	60.7	87.7	95.1	84.1	65.1	42.9	18.5	5.2	16.9	46.3
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	49.4	51.0	42.2	54.3	51.3	45.2	35.4	28.2	36.8	39.9	37.0	45.2	43.0
C .J. Strike	ROR	64.7	65.9	56.8	69.8	66.7	54.6	36.6	31.3	44.0	50.9	48.6	57.1	53.9
Cascade	ROR	1.5	1.6	2.8	5.9	5.3	12.0	10.2	13.3	8.8	2.0	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	35.1	35.3	27.8	38.9	37.2	31.2	22.9	15.9	23.0	25.8	23.2	29.7	28.8
Milner	ROR	41.4	43.3	22.1	43.4	42.3	27.1	6.2	-	-	-	-	25.7	21.0
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	11.3	12.0	11.0
Swan Falls	ROR	20.9	21.3	18.5	22.4	21.5	17.8	12.9	11.0	14.8	16.8	16.0	18.6	17.7
Twin Falls	ROR	41.5	43.3	24.3	46.4	41.6	28.9	10.5	-	-	6.6	7.4	27.1	23.1
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.1	19.1	18.0	19.1	17.5	19.2	14.0	8.8	14.0	16.0	14.0	19.1	16.5
Upper Salmon 3&4	ROR	17.7	17.7	16.6	17.7	17.7	16.2	13.2	8.7	13.2	14.9	13.1	17.6	15.4
HCC Total		**708.9**	**825.7**	**815.3**	**1,025.4**	**980.9**	**932.3**	**564.0**	**386.6**	**483.5**	**459.8**	**361.2**	**562.1**	**675.5**
ROR Total		**355.1**	**364.7**	**295.7**	**418.1**	**429.5**	**386.5**	**284.9**	**216.8**	**232.8**	**230.2**	**203.7**	**296.8**	**309.6**
Total		**1,064.0**	**1,190.4**	**1,111.0**	**1,443.5**	**1,410.4**	**1,318.8**	**848.9**	**603.4**	**716.3**	**690.0**	**564.9**	**858.9**	**985.0**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2021**	**2/2021**	**3/2021**	**4/2021**	**5/2021**	**6/2021**	**7/2021**	**8/2021**	**9/2021**	**10/2021**	**11/2021**	**12/2021**	**aMW**
Brownlee	HCC*	317.6	356.8	343.3	439.9	434.6	418.1	248.4	163.5	204.4	195.9	153.1	248.5	293.7
Oxbow	HCC	131.0	154.3	156.0	191.4	177.1	169.8	105.4	74.7	92.9	89.1	69.2	104.6	126.3
Hells Canyon	HCC	257.7	306.2	314.9	392.0	365.9	342.7	208.9	147.0	182.4	175.7	137.9	207.4	253.2
1000 Springs	ROR**	25.5	26.9	26.4	60.5	87.5	95.1	84.1	65.0	42.4	18.0	-	15.6	45.6
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	49.2	50.7	41.9	54.0	51.1	44.8	35.2	28.0	36.6	39.7	36.8	44.3	42.7
C .J. Strike	ROR	64.4	65.0	56.4	69.4	66.4	54.3	36.4	31.1	43.6	50.6	48.4	55.7	53.5
Cascade	ROR	1.5	1.6	2.8	5.9	5.3	12.0	10.2	13.3	8.8	2.0	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	34.7	34.9	27.6	38.5	37.0	30.8	22.8	15.7	22.8	25.6	23.0	29.5	28.6
Milner	ROR	41.1	42.9	21.4	43.0	42.0	26.9	6.2	-	-	-	-	24.9	20.7
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	9.7	12.0	10.8
Swan Falls	ROR	20.8	21.1	18.4	22.3	21.4	17.7	12.8	10.9	14.7	16.7	16.0	18.2	17.6
Twin Falls	ROR	41.3	43.0	23.4	45.9	41.3	28.5	10.5	-	-	6.6	6.0	26.9	22.8
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.1	19.1	17.8	19.1	17.5	19.2	13.9	8.6	13.8	15.8	13.8	19.0	16.4
Upper Salmon 3&4	ROR	17.7	17.7	16.4	17.7	17.7	16.2	13.1	8.6	13.0	14.7	13.0	17.5	15.3
HCC Total		**706.3**	**817.3**	**814.2**	**1,023.3**	**977.5**	**930.6**	**562.7**	**385.2**	**479.6**	**460.7**	**360.2**	**560.5**	**673.2**
ROR Total		**353.4**	**362.0**	**292.2**	**415.8**	**427.9**	**384.7**	**284.1**	**215.7**	**231.0**	**228.5**	**194.6**	**291.4**	**306.8**
Total		**1,059.7**	**1,179.3**	**1,106.4**	**1,439.1**	**1,405.4**	**1,315.3**	**846.8**	**600.9**	**710.6**	**689.2**	**554.8**	**851.9**	**980.0**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2022**	**2/2022**	**3/2022**	**4/2022**	**5/2022**	**6/2022**	**7/2022**	**8/2022**	**9/2022**	**10/2022**	**11/2022**	**12/2022**	**aMW**
Brownlee	HCC*	316.4	353.8	342.8	438.9	433.0	417.3	247.7	162.8	201.2	196.4	153.6	247.3	292.6
Oxbow	HCC	130.5	153.0	155.7	191.0	176.8	169.5	105.1	74.4	91.1	89.0	69.4	104.1	125.8
Hells Canyon	HCC	256.8	303.7	314.4	391.2	364.6	342.1	208.3	146.4	178.9	175.5	138.2	206.4	252.2
1000 Springs	ROR**	24.7	26.5	26.1	60.3	87.3	95.1	84.1	65.0	42.3	17.5	-	14.3	45.3
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	48.9	50.0	41.4	53.8	50.9	44.5	35.0	27.8	36.4	39.5	36.6	43.4	42.4
C .J. Strike	ROR	64.0	65.0	56.0	69.1	66.1	54.0	36.2	30.8	43.3	50.3	47.8	54.5	53.1
Cascade	ROR	1.5	1.6	2.8	5.9	5.3	12.0	10.2	13.3	8.8	2.0	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	34.4	34.7	27.3	38.2	36.8	30.4	22.6	15.6	22.6	25.4	22.8	29.3	28.3
Milner	ROR	40.6	42.3	18.8	42.8	41.7	26.2	6.2	-	-	-	-	24.9	20.3
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	9.7	12.0	10.8
Swan Falls	ROR	20.4	21.0	18.3	22.2	21.3	17.6	12.8	10.8	14.6	16.4	15.8	17.9	17.4
Twin Falls	ROR	40.1	41.4	21.6	45.8	41.1	28.3	10.5	-	-	6.6	6.0	26.9	22.4
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.1	19.1	17.6	19.1	17.5	19.2	13.8	8.5	13.7	15.7	13.7	18.8	16.3
Upper Salmon 3&4	ROR	17.7	17.7	16.3	17.7	17.7	16.2	13.0	8.5	12.9	14.6	12.9	17.3	15.2
HCC Total		**703.7**	**810.5**	**812.9**	**1,021.1**	**974.4**	**928.9**	**561.1**	**383.6**	**471.2**	**460.9**	**361.2**	**557.8**	**670.6**
ROR Total		**349.5**	**358.4**	**285.9**	**414.4**	**426.4**	**382.7**	**283.3**	**214.8**	**230.0**	**226.8**	**193.2**	**287.1**	**304.4**
Total		**1,053.2**	**1,168.9**	**1,098.8**	**1,435.5**	**1,400.8**	**1,311.6**	**844.4**	**598.4**	**701.2**	**687.7**	**554.4**	**844.9**	**975.0**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2023**	**2/2023**	**3/2023**	**4/2023**	**5/2023**	**6/2023**	**7/2023**	**8/2023**	**9/2023**	**10/2023**	**11/2023**	**12/2023**	**aMW**
Brownlee	HCC*	315.3	351.6	342.5	438.1	431.7	416.5	247.1	162.2	198.5	196.2	153.6	246.7	291.7
Oxbow	HCC	130.1	152.1	155.6	190.6	176.5	169.2	104.8	74.1	89.7	88.7	69.3	103.8	125.4
Hells Canyon	HCC	255.9	301.9	314.2	390.5	363.6	341.5	207.8	145.8	176.2	175.0	138.1	205.9	251.4
1000 Springs	ROR**	24.5	25.6	25.9	60.0	87.1	95.1	84.1	64.9	42.3	17.4	-	13.8	45.1
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	48.7	48.8	41.3	53.6	50.7	44.2	34.9	27.6	36.2	39.3	36.4	42.5	42.0
C .J. Strike	ROR	63.6	64.6	55.9	68.8	65.8	53.8	36.0	30.6	43.0	50.1	47.6	53.3	52.8
Cascade	ROR	1.5	1.6	2.8	5.9	5.3	12.0	10.2	13.3	8.8	2.0	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	34.2	34.0	27.1	37.8	36.6	30.0	22.5	15.4	22.4	25.3	22.6	28.5	28.0
Milner	ROR	40.3	40.7	18.5	42.5	41.4	25.4	6.2	-	-	-	-	23.9	19.9
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	9.7	12.0	10.8
Swan Falls	ROR	20.3	20.9	18.2	22.1	21.3	17.6	12.7	10.7	14.5	16.4	15.8	17.5	17.3
Twin Falls	ROR	39.9	40.8	21.3	45.6	40.9	27.8	10.5	-	-	6.6	6.0	25.4	22.1
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.1	19.1	17.4	19.1	17.5	19.2	13.7	8.4	13.5	15.6	13.5	18.2	16.2
Upper Salmon 3&4	ROR	17.7	17.7	16.1	17.7	17.7	16.2	12.9	8.4	12.7	14.5	12.8	16.8	15.1
HCC Total		**701.3**	**805.6**	**812.3**	**1,019.2**	**971.7**	**927.2**	**559.7**	**382.1**	**464.4**	**459.9**	**361.0**	**556.4**	**668.4**
ROR Total		**347.9**	**352.9**	**284.2**	**412.6**	**425.0**	**380.5**	**282.6**	**213.8**	**228.7**	**226.0**	**192.3**	**279.7**	**302.2**
Total		**1,049.2**	**1,158.5**	**1,096.5**	**1,431.8**	**1,396.7**	**1,307.7**	**842.3**	**595.9**	**693.1**	**685.9**	**553.3**	**836.1**	**970.6**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2024**	**2/2024**	**3/2024**	**4/2024**	**5/2024**	**6/2024**	**7/2024**	**8/2024**	**9/2024**	**10/2024**	**11/2024**	**12/2024**	**aMW**
Brownlee	HCC*	314.2	350.3	345.8	437.2	430.1	415.7	246.5	161.5	196.3	196.1	153.6	245.6	291.1
Oxbow	HCC	129.6	151.5	157.0	190.3	176.3	168.9	104.6	73.8	88.6	88.6	69.3	103.3	125.1
Hells Canyon	HCC	255.0	300.9	317.0	389.8	362.4	340.9	207.3	145.2	174.0	174.8	138.0	205.0	250.9
1000 Springs	ROR**	24.3	25.4	25.6	59.8	86.9	95.0	84.1	64.9	42.1	17.4	-	13.8	44.9
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	48.4	48.4	41.1	53.4	50.5	43.8	34.7	27.4	35.9	39.0	36.3	41.7	41.7
C .J. Strike	ROR	63.2	64.2	55.7	68.5	65.5	53.5	35.8	30.3	42.6	49.6	47.3	52.5	52.4
Cascade	ROR	1.5	1.6	2.8	5.9	5.3	12.0	10.2	13.3	8.8	2.0	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	34.0	33.7	26.9	37.5	36.4	29.6	22.4	15.2	22.2	25.1	22.4	27.6	27.8
Milner	ROR	40.1	40.4	18.1	42.2	41.1	24.9	6.2	-	-	-	-	21.7	19.6
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	9.7	12.0	10.8
Swan Falls	ROR	20.2	20.2	18.1	22.0	21.2	17.5	12.6	10.6	14.4	16.3	15.7	17.3	17.2
Twin Falls	ROR	39.6	40.5	20.9	45.4	40.6	27.3	10.5	-	-	6.6	6.0	23.5	21.7
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.1	19.1	17.2	19.1	17.5	19.2	13.5	8.3	13.3	15.4	13.4	17.5	16.1
Upper Salmon 3&4	ROR	17.7	17.7	15.9	17.7	17.7	16.2	12.8	8.3	12.6	14.4	12.7	16.2	15.0
HCC Total		**698.8**	**802.7**	**819.8**	**1,017.3**	**968.7**	**925.5**	**558.4**	**380.5**	**458.8**	**459.5**	**360.9**	**553.9**	**667.1**
ROR Total		**346.2**	**350.3**	**282.0**	**411.0**	**423.4**	**378.2**	**281.7**	**212.8**	**227.3**	**224.6**	**191.4**	**271.6**	**300.0**
Total		**1,045.0**	**1,153.0**	**1,101.8**	**1,428.3**	**1,392.1**	**1,303.7**	**840.1**	**593.3**	**686.1**	**684.1**	**552.3**	**825.5**	**967.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2025**	**2/2025**	**3/2025**	**4/2025**	**5/2025**	**6/2025**	**7/2025**	**8/2025**	**9/2025**	**10/2025**	**11/2025**	**12/2025**	**aMW**
Brownlee	HCC*	313.2	349.2	344.9	436.5	429.4	415.0	245.9	160.9	194.4	196.1	153.8	244.7	290.3
Oxbow	HCC	129.2	151.1	156.7	190.0	175.8	168.6	104.3	73.5	87.6	88.5	69.4	103.0	124.8
Hells Canyon	HCC	254.2	300.0	316.2	389.2	361.8	340.3	206.8	144.7	172.1	174.6	138.2	204.3	250.2
1000 Springs	ROR**	23.9	25.2	25.4	59.5	86.7	94.7	84.1	64.9	42.0	17.3	-	13.4	44.8
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	48.1	48.1	40.9	53.2	50.3	43.5	34.5	27.2	35.7	38.9	36.0	41.0	41.5
C .J. Strike	ROR	62.9	63.8	55.3	68.2	65.3	53.3	35.6	30.1	42.3	49.4	47.1	51.4	52.1
Cascade	ROR	1.5	1.6	2.8	5.9	5.3	12.0	10.2	13.3	8.8	2.0	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	33.6	33.5	26.7	37.2	36.2	29.3	22.2	15.1	21.9	24.9	22.3	26.9	27.5
Milner	ROR	39.5	40.3	17.8	42.0	40.8	24.6	6.2	-	-	-	-	20.0	19.3
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	9.7	12.0	10.8
Swan Falls	ROR	20.1	20.0	18.0	21.9	21.1	17.4	12.6	10.6	14.3	16.2	15.6	17.0	17.1
Twin Falls	ROR	39.1	40.3	20.6	45.2	40.4	27.0	10.5	-	-	6.6	6.0	22.0	21.5
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.1	19.1	17.1	19.1	17.5	18.9	13.4	8.1	13.1	15.3	13.3	16.9	15.9
Upper Salmon 3&4	ROR	17.7	17.7	15.8	17.7	17.7	16.2	12.7	8.2	12.4	14.3	12.6	15.7	14.9
HCC Total		**696.6**	**800.3**	**817.8**	**1,015.7**	**967.0**	**923.9**	**557.0**	**379.1**	**454.0**	**459.2**	**361.4**	**552.0**	**665.3**
ROR Total		**343.6**	**348.7**	**280.1**	**409.4**	**422.0**	**376.1**	**280.9**	**212.0**	**225.9**	**223.7**	**190.5**	**264.1**	**298.1**
Total		**1,040.2**	**1,149.0**	**1,097.9**	**1,425.1**	**1,389.0**	**1,300.0**	**837.9**	**591.1**	**679.9**	**682.9**	**551.9**	**816.1**	**963.4**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2026**	**2/2026**	**3/2026**	**4/2026**	**5/2026**	**6/2026**	**7/2026**	**8/2026**	**9/2026**	**10/2026**	**11/2026**	**12/2026**	**aMW**
Brownlee	HCC*	312.2	348.2	343.9	435.7	429.4	414.2	245.3	160.3	192.5	196.0	153.8	244.5	289.7
Oxbow	HCC	128.8	150.6	156.2	189.6	175.8	168.2	104.0	73.2	86.6	88.3	69.3	102.9	124.5
Hells Canyon	HCC	253.4	299.1	315.4	388.5	361.8	339.7	206.3	144.1	170.2	174.2	138.1	204.1	249.6
1000 Springs	ROR**	23.7	25.0	25.1	59.3	86.6	94.4	84.0	64.8	42.0	17.9	-	12.4	44.6
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	47.6	47.9	40.6	53.0	50.1	43.2	34.5	27.0	35.4	38.7	35.9	40.3	41.2
C .J. Strike	ROR	62.6	63.0	54.7	67.9	64.3	52.9	35.3	29.9	42.0	49.1	46.6	50.4	51.6
Cascade	ROR	1.5	1.6	2.8	5.9	5.3	12.0	10.2	13.3	8.8	2.0	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	33.2	33.3	26.5	36.9	36.0	29.2	22.1	14.9	21.7	24.7	22.1	26.2	27.2
Milner	ROR	39.3	40.1	17.5	41.7	40.6	24.2	6.2	-	-	-	-	18.0	19.0
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	9.7	12.0	10.8
Swan Falls	ROR	20.0	19.9	17.9	21.8	20.9	17.3	12.5	10.5	14.2	16.2	15.5	16.7	17.0
Twin Falls	ROR	38.9	40.1	20.3	45.0	40.2	26.7	10.5	-	-	6.6	6.0	20.5	21.2
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.1	19.1	16.9	19.1	17.5	18.9	13.3	8.0	13.0	15.1	13.1	16.4	15.8
Upper Salmon 3&4	ROR	17.7	17.7	15.7	17.7	17.7	16.2	12.6	8.1	12.3	14.2	12.4	15.2	14.8
HCC Total		**694.4**	**797.9**	**815.5**	**1,013.8**	**967.0**	**922.1**	**555.6**	**377.6**	**449.3**	**458.5**	**361.2**	**551.5**	**663.7**
ROR Total		**341.7**	**346.8**	**277.7**	**407.8**	**419.9**	**374.2**	**280.1**	**211.0**	**224.7**	**223.3**	**189.2**	**255.9**	**296.0**
Total		**1,036.1**	**1,144.7**	**1,093.2**	**1,421.6**	**1,386.8**	**1,296.3**	**835.7**	**588.6**	**674.0**	**681.8**	**550.4**	**807.4**	**959.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2027**	**2/2027**	**3/2027**	**4/2027**	**5/2027**	**6/2027**	**7/2027**	**8/2027**	**9/2027**	**10/2027**	**11/2027**	**12/2027**	**aMW**
Brownlee	HCC*	311.1	347.2	343.1	434.9	429.0	413.4	244.6	159.7	190.0	196.6	154.2	242.7	288.9
Oxbow	HCC	128.4	150.2	155.9	189.3	175.6	167.9	103.8	72.9	85.3	88.4	69.5	102.1	124.1
Hells Canyon	HCC	252.6	298.3	314.7	387.9	361.5	339.1	205.7	143.5	167.7	174.4	138.4	202.6	248.9
1000 Springs	ROR**	23.6	24.8	24.9	59.1	86.4	94.2	84.0	64.8	41.9	17.3	-	11.4	44.4
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	47.4	47.6	40.4	52.1	49.9	42.9	34.4	26.8	35.2	38.4	35.9	39.6	40.9
C .J. Strike	ROR	62.0	61.5	54.0	67.6	63.9	52.5	35.1	29.6	41.7	48.9	46.3	49.2	51.0
Cascade	ROR	1.5	1.6	2.8	5.9	5.3	12.0	10.2	13.3	8.8	2.0	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	33.0	33.0	26.0	36.6	35.8	29.1	22.0	14.8	21.5	24.5	21.9	25.4	27.0
Milner	ROR	39.1	39.8	17.2	40.9	40.3	23.9	6.2	-	-	-	-	16.0	18.6
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	9.7	12.0	10.8
Swan Falls	ROR	19.9	19.8	17.7	21.8	20.7	17.2	12.4	10.4	14.1	16.1	15.4	16.2	16.8
Twin Falls	ROR	38.7	39.8	20.0	43.8	40.0	26.4	10.5	-	-	6.6	6.0	18.9	20.9
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.2	19.1	16.6	19.1	17.6	18.7	13.2	7.9	12.8	15.0	13.0	15.8	15.7
Upper Salmon 3&4	ROR	17.7	17.7	15.4	17.7	17.7	16.2	12.5	8.0	12.2	14.0	12.3	14.7	14.7
HCC Total		**692.1**	**795.7**	**813.7**	**1,012.1**	**966.1**	**920.4**	**554.1**	**376.1**	**443.0**	**459.4**	**362.1**	**547.4**	**661.9**
ROR Total		**340.2**	**343.8**	**274.7**	**404.1**	**418.3**	**372.3**	**279.4**	**210.1**	**223.6**	**221.6**	**188.4**	**247.0**	**293.6**
Total		**1,032.3**	**1,139.5**	**1,088.4**	**1,416.2**	**1,384.4**	**1,292.7**	**833.5**	**586.2**	**666.6**	**681.0**	**550.5**	**794.4**	**955.5**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2028**	**2/2028**	**3/2028**	**4/2028**	**5/2028**	**6/2028**	**7/2028**	**8/2028**	**9/2028**	**10/2028**	**11/2028**	**12/2028**	**aMW**
Brownlee	HCC*	310.1	346.1	340.1	434.1	427.8	412.6	244.0	159.0	188.1	196.7	153.9	242.1	287.9
Oxbow	HCC	128.0	149.8	154.6	189.0	175.1	167.6	103.5	72.6	84.3	88.4	69.3	101.8	123.7
Hells Canyon	HCC	251.8	297.4	312.2	387.2	360.6	338.5	205.3	143.0	165.8	174.3	138.0	202.1	248.0
1000 Springs	ROR**	23.5	24.6	23.9	58.2	86.3	94.0	84.0	64.7	41.9	17.0	-	10.4	44.0
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	47.1	47.3	39.8	51.8	49.7	42.6	34.3	26.7	34.9	38.2	35.7	38.9	40.6
C .J. Strike	ROR	61.3	61.1	53.0	67.3	63.5	52.1	34.9	29.4	41.3	48.5	46.1	48.1	50.6
Cascade	ROR	1.5	1.6	2.8	5.9	5.3	12.0	10.2	13.3	8.8	2.0	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	32.7	32.8	25.5	36.4	35.4	28.8	21.8	14.6	21.3	24.4	21.8	24.7	26.7
Milner	ROR	38.9	39.5	16.2	43.5	40.2	23.6	6.2	-	-	-	-	14.4	18.5
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	9.6	12.0	10.8
Swan Falls	ROR	19.7	19.7	17.5	21.7	20.4	17.1	12.4	10.3	14.2	16.0	15.3	15.9	16.7
Twin Falls	ROR	38.5	39.6	18.7	42.3	39.8	26.2	10.5	-	-	6.6	5.9	17.3	20.5
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.2	19.2	16.1	19.1	17.6	18.5	13.1	7.8	12.6	14.9	12.9	15.2	15.5
Upper Salmon 3&4	ROR	17.7	17.7	15.0	17.7	17.7	16.2	12.4	7.9	12.0	13.9	12.2	14.2	14.6
HCC Total		**689.9**	**793.3**	**806.9**	**1,010.3**	**963.5**	**918.7**	**552.8**	**374.6**	**438.1**	**459.4**	**361.2**	**546.0**	**659.6**
ROR Total		**338.2**	**342.2**	**268.2**	**403.4**	**416.6**	**370.3**	**278.7**	**209.2**	**222.3**	**220.3**	**187.4**	**238.9**	**291.3**
Total		**1,028.1**	**1,135.5**	**1,075.1**	**1,413.7**	**1,380.0**	**1,289.0**	**831.5**	**583.8**	**660.4**	**679.7**	**548.6**	**784.9**	**950.9**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2029**	**2/2029**	**3/2029**	**4/2029**	**5/2029**	**6/2029**	**7/2029**	**8/2029**	**9/2029**	**10/2029**	**11/2029**	**12/2029**	**aMW**
Brownlee	HCC*	309.1	345.1	339.7	433.4	427.0	411.9	243.5	158.4	185.8	197.0	154.2	241.1	287.2
Oxbow	HCC	127.6	149.3	154.4	188.7	174.8	167.3	103.3	72.3	83.2	88.3	69.4	101.4	123.3
Hells Canyon	HCC	251.0	296.6	311.8	386.6	359.9	337.9	204.8	142.5	163.6	174.3	138.2	201.2	247.4
1000 Springs	ROR**	23.3	24.5	23.7	58.0	85.8	93.8	84.0	64.7	41.8	17.3	-	9.4	43.9
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	46.9	47.1	39.5	51.6	49.5	42.3	34.1	26.5	34.7	38.1	35.4	38.2	40.3
C .J. Strike	ROR	61.0	60.8	52.6	66.5	63.2	51.7	34.7	29.2	41.0	48.2	45.8	47.1	50.2
Cascade	ROR	1.5	1.6	2.8	5.9	5.3	12.0	10.2	13.3	8.8	2.0	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	32.5	32.5	25.0	36.1	34.2	28.5	21.7	14.4	21.1	24.2	21.5	24.0	26.3
Milner	ROR	38.6	39.3	14.5	42.9	36.4	23.3	6.2	-	-	-	-	12.5	17.8
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	9.6	12.0	10.8
Swan Falls	ROR	19.6	19.6	17.3	21.4	20.3	17.0	12.3	10.3	14.1	15.9	15.2	15.6	16.6
Twin Falls	ROR	38.3	39.4	18.4	41.8	36.5	25.9	10.5	-	-	6.6	5.9	15.8	19.9
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.2	19.2	15.7	19.1	17.6	18.3	13.0	7.7	12.5	14.8	12.7	14.7	15.4
Upper Salmon 3&4	ROR	17.7	17.7	14.7	17.7	17.7	16.2	12.3	7.8	11.9	13.8	12.1	13.8	14.5
HCC Total		**687.7**	**791.0**	**805.9**	**1,008.7**	**961.7**	**917.1**	**551.6**	**373.2**	**432.6**	**459.6**	**361.8**	**543.7**	**657.9**
ROR Total		**336.7**	**340.8**	**263.9**	**400.5**	**407.2**	**368.2**	**277.9**	**208.4**	**221.2**	**219.7**	**186.1**	**230.9**	**288.5**
Total		**1,024.4**	**1,131.8**	**1,069.8**	**1,409.2**	**1,368.9**	**1,285.3**	**829.5**	**581.6**	**653.8**	**679.3**	**547.9**	**774.6**	**946.3**

*HCC=HellsCanyonComplex,**ROR=RunofRiver

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2030**	**2/2030**	**3/2030**	**4/2030**	**5/2030**	**6/2030**	**7/2030**	**8/2030**	**9/2030**	**10/2030**	**11/2030**	**12/2030**	**aMW**
Brownlee	HCC*	308.1	344.0	339.3	432.6	426.2	411.0	242.8	157.8	184.7	197.1	153.9	240.3	286.5
Oxbow	HCC	127.1	148.9	154.2	188.3	174.5	167.0	103.0	72.0	82.6	88.3	69.2	101.0	123.0
Hells Canyon	HCC	250.2	295.7	311.5	385.9	359.3	337.3	204.3	141.9	162.4	174.2	137.9	200.5	246.8
1000 Springs	ROR**	23.1	24.3	23.4	57.8	85.8	93.7	84.0	64.7	41.7	17.2	-	8.4	43.7
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	46.7	46.8	38.9	51.4	49.3	42.0	34.0	26.3	34.4	38.0	35.4	37.5	40.1
C .J. Strike	ROR	60.7	60.4	52.3	66.1	62.9	51.3	34.5	28.9	40.7	48.0	45.5	46.7	49.8
Cascade	ROR	1.5	1.6	2.8	5.9	5.3	12.0	10.2	13.3	8.8	2.0	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	32.3	32.1	25.0	35.8	34.0	28.3	21.6	14.3	20.8	24.1	21.3	23.7	26.1
Milner	ROR	38.4	39.0	13.5	42.6	36.2	23.0	6.2	-	-	-	-	11.4	17.5
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	9.6	12.0	10.8
Swan Falls	ROR	19.5	19.5	17.2	21.3	20.2	16.9	12.2	10.2	14.0	15.9	15.4	15.6	16.5
Twin Falls	ROR	38.1	39.1	17.2	41.4	36.2	25.6	10.5	-	-	6.6	5.9	14.2	19.6
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.2	19.2	15.7	19.1	17.6	18.1	12.9	7.5	12.3	14.6	12.5	14.5	15.3
Upper Salmon 3&4	ROR	17.7	17.7	14.7	17.7	17.7	16.2	12.3	7.7	11.7	13.7	11.9	13.6	14.4
HCC Total		**685.4**	**788.6**	**805.0**	**1,006.8**	**959.9**	**915.3**	**550.1**	**371.7**	**429.7**	**459.6**	**361.0**	**541.8**	**656.2**
ROR Total		**335.3**	**338.8**	**260.4**	**398.6**	**405.9**	**366.3**	**277.3**	**207.4**	**219.7**	**218.9**	**185.4**	**225.4**	**286.6**
Total		**1,020.7**	**1,127.4**	**1,065.4**	**1,405.4**	**1,365.8**	**1,281.6**	**827.4**	**579.1**	**649.4**	**678.5**	**546.4**	**767.2**	**942.9**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2031**	**2/2031**	**3/2031**	**4/2031**	**5/2031**	**6/2031**	**7/2031**	**8/2031**	**9/2031**	**10/2031**	**11/2031**	**12/2031**	**aMW**
Brownlee	HCC*	307.1	343.0	338.8	431.9	425.3	410.3	242.3	157.2	179.2	197.0	154.4	239.4	285.5
Oxbow	HCC	126.7	148.5	154.0	188.0	174.2	166.7	102.8	71.7	81.7	88.1	69.4	100.7	122.7
Hells Canyon	HCC	249.4	294.8	311.0	385.3	358.6	336.8	203.8	141.3	160.4	173.8	138.3	199.8	246.1
1000 Springs	ROR**	23.0	23.8	22.6	57.0	85.8	93.5	84.0	64.6	41.7	17.3	-	7.4	43.4
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	46.4	46.5	38.6	51.2	49.1	42.0	33.8	26.1	34.2	37.8	35.3	36.8	39.8
C .J. Strike	ROR	60.3	60.0	52.0	65.2	62.7	50.9	34.3	28.7	40.5	47.7	45.3	46.5	49.5
Cascade	ROR	1.5	1.6	2.8	5.9	5.3	12.0	10.2	13.3	8.8	2.0	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	32.1	31.9	24.9	35.5	33.8	28.0	21.4	14.1	20.6	23.9	21.2	23.7	25.9
Milner	ROR	38.2	38.5	13.5	42.0	35.9	22.6	6.2	-	-	-	-	9.8	17.2
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	9.6	12.0	10.8
Swan Falls	ROR	19.4	19.4	17.1	21.1	20.1	16.7	12.2	10.1	13.9	15.8	15.3	15.6	16.4
Twin Falls	ROR	38.0	38.2	16.8	40.9	36.0	25.3	10.5	-	-	6.6	5.9	12.6	19.2
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.2	19.2	15.6	19.1	17.6	17.9	12.8	7.4	12.1	14.5	12.4	14.5	15.2
Upper Salmon 3&4	ROR	17.7	17.7	14.6	17.7	17.7	16.2	12.2	7.6	11.6	13.6	11.8	13.6	14.3
HCC Total		**683.2**	**786.3**	**803.8**	**1,005.2**	**958.1**	**913.8**	**548.9**	**370.2**	**421.2**	**458.9**	**362.1**	**539.9**	**654.3**
ROR Total		**333.9**	**335.9**	**258.2**	**395.1**	**404.7**	**364.3**	**276.5**	**206.4**	**218.7**	**218.0**	**184.7**	**220.3**	**284.7**
Total		**1,017.1**	**1,122.2**	**1,062.0**	**1,400.3**	**1,362.7**	**1,278.1**	**825.4**	**576.6**	**639.9**	**676.9**	**546.8**	**760.2**	**939.0**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2032**	**2/2032**	**3/2032**	**4/2032**	**5/2032**	**6/2032**	**7/2032**	**8/2032**	**9/2032**	**10/2032**	**11/2032**	**12/2032**	**aMW**
Brownlee	HCC*	306.1	342.0	338.4	431.1	424.6	409.3	241.7	156.5	177.0	197.3	154.3	238.7	284.7
Oxbow	HCC	126.3	148.0	153.8	187.7	173.9	166.3	102.5	71.4	80.5	88.1	69.3	100.4	122.3
Hells Canyon	HCC	248.6	294.0	310.7	384.7	358.0	335.9	203.4	140.8	158.1	173.8	138.1	199.2	245.4
1000 Springs	ROR**	22.9	23.7	21.7	56.8	85.6	93.3	84.0	64.6	41.6	17.2	-	6.4	43.1
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	46.2	46.3	38.5	51.1	48.9	42.0	33.7	25.9	33.9	37.7	35.1	36.5	39.7
C .J. Strike	ROR	60.0	59.7	51.7	64.9	62.4	50.5	34.1	28.4	40.2	47.6	45.1	46.2	49.2
Cascade	ROR	1.5	1.6	2.8	5.9	5.3	12.0	10.2	13.3	8.8	2.0	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	31.9	31.7	24.7	35.0	33.7	27.7	21.3	14.0	20.4	23.8	21.0	23.7	25.7
Milner	ROR	38.0	38.2	12.5	40.8	35.7	22.3	6.2	-	-	-	-	8.2	16.8
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	9.6	12.0	10.8
Swan Falls	ROR	19.4	19.3	17.0	21.0	20.1	16.5	12.1	10.0	13.8	15.7	15.3	15.6	16.3
Twin Falls	ROR	37.8	38.0	16.0	39.9	35.8	25.0	10.5	-	-	6.6	5.9	11.0	18.9
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.2	19.2	15.5	19.1	17.6	17.7	12.7	7.3	12.0	14.4	12.3	14.5	15.1
Upper Salmon 3&4	ROR	17.7	17.7	14.5	17.7	17.7	16.2	12.1	7.5	11.4	13.5	11.7	13.6	14.3
HCC Total		**681.0**	**784.0**	**802.9**	**1,003.5**	**956.4**	**911.5**	**547.6**	**368.7**	**415.6**	**459.2**	**361.7**	**538.3**	**652.5**
ROR Total		**332.7**	**334.5**	**254.6**	**391.7**	**403.5**	**362.4**	**275.8**	**205.5**	**217.4**	**217.3**	**183.9**	**215.5**	**282.9**
Total		**1,013.7**	**1,118.5**	**1,057.5**	**1,395.2**	**1,359.9**	**1,273.9**	**823.4**	**574.2**	**633.0**	**676.5**	**545.6**	**753.8**	**935.4**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2033**	**2/2033**	**3/2033**	**4/2033**	**5/2033**	**6/2033**	**7/2033**	**8/2033**	**9/2033**	**10/2033**	**11/2033**	**12/2033**	**aMW**
Brownlee	HCC*	305.2	340.9	337.8	430.3	423.7	408.0	241.1	155.9	174.7	197.8	154.3	237.6	283.9
Oxbow	HCC	126.0	147.6	153.5	187.4	173.5	165.8	102.3	71.1	79.4	88.2	69.3	99.9	122.0
Hells Canyon	HCC	247.9	293.2	310.2	384.0	357.3	334.9	202.9	140.2	155.9	174.0	138.0	198.3	244.7
1000 Springs	ROR**	22.7	23.5	20.8	56.6	85.4	93.1	83.9	64.5	41.5	16.9	-	5.4	42.9
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	46.0	46.0	38.2	50.9	48.7	42.0	33.5	25.7	33.7	37.4	34.9	36.5	39.5
C .J. Strike	ROR	59.7	59.3	51.3	64.6	62.1	50.2	33.9	28.2	39.9	47.4	44.8	46.0	49.0
Cascade	ROR	1.5	1.6	2.8	5.9	5.3	12.0	10.2	13.3	8.8	2.0	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	31.7	31.5	23.7	34.5	33.5	27.5	21.2	13.8	20.2	23.6	20.9	23.7	25.5
Milner	ROR	37.7	37.9	11.9	38.0	35.4	22.0	6.2	-	-	-	-	6.4	16.3
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	9.6	12.0	10.8
Swan Falls	ROR	19.3	19.2	16.9	21.0	20.0	16.4	12.0	9.9	13.7	15.6	15.2	15.6	16.2
Twin Falls	ROR	37.6	37.8	14.6	37.4	35.6	24.8	10.5	-	-	6.6	5.9	9.6	18.4
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.2	19.2	14.7	19.1	17.6	17.5	12.6	7.2	11.8	14.3	12.2	14.5	15.0
Upper Salmon 3&4	ROR	17.7	17.7	13.8	17.7	17.7	16.2	12.0	7.4	11.3	13.4	11.7	13.6	14.2
HCC Total		**679.1**	**781.7**	**801.5**	**1,001.7**	**954.4**	**908.7**	**546.3**	**367.2**	**410.0**	**460.0**	**361.6**	**535.8**	**650.7**
ROR Total		**331.2**	**332.8**	**248.4**	**385.2**	**402.0**	**360.9**	**274.9**	**204.5**	**216.2**	**216.0**	**183.1**	**211.1**	**280.5**
Total		**1,010.3**	**1,114.5**	**1,049.9**	**1,386.9**	**1,356.4**	**1,269.6**	**821.2**	**571.7**	**626.2**	**676.0**	**544.7**	**746.9**	**931.2**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2034**	**2/2034**	**3/2034**	**4/2034**	**5/2034**	**6/2034**	**7/2034**	**8/2034**	**9/2034**	**10/2034**	**11/2034**	**12/2034**	**aMW**
Brownlee	HCC*	304.1	339.2	337.0	429.6	422.9	406.7	240.5	155.3	172.7	197.7	154.7	236.6	283.1
Oxbow	HCC	125.5	146.9	153.2	187.1	173.2	165.3	102.0	70.8	78.4	88.0	69.4	99.5	121.6
Hells Canyon	HCC	247.1	291.7	309.4	383.4	356.7	333.9	202.4	139.6	154.0	173.7	138.3	197.5	244.0
1000 Springs	ROR**	22.4	23.3	19.9	56.4	85.3	92.9	83.9	64.5	41.5	16.5	-	-	42.2
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	45.7	45.7	38.0	50.7	48.5	41.8	33.3	25.5	33.4	37.2	34.7	36.5	39.3
C .J. Strike	ROR	59.4	58.9	51.0	64.3	61.8	50.0	33.7	28.0	39.5	47.1	44.7	45.8	48.7
Cascade	ROR	1.5	1.6	2.8	5.9	5.3	12.0	10.2	13.3	8.8	2.0	1.4	1.4	5.5
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	31.5	31.2	23.5	34.3	33.3	27.2	21.0	13.6	20.0	23.4	20.7	23.7	25.3
Milner	ROR	37.3	37.6	11.6	36.7	35.2	21.7	6.2	-	-	-	-	6.2	16.0
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	9.6	12.0	10.8
Swan Falls	ROR	19.1	19.1	16.8	20.9	19.9	16.3	12.0	9.9	13.6	15.6	15.2	15.6	16.2
Twin Falls	ROR	37.2	37.5	14.3	36.3	35.4	24.5	10.5	-	-	6.6	5.9	9.5	18.1
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	19.2	19.2	14.6	19.1	17.6	17.3	12.5	7.0	11.6	14.1	12.0	14.5	14.9
Upper Salmon 3&4	ROR	17.7	17.7	13.7	17.7	17.7	16.0	11.9	7.3	11.2	13.3	11.5	13.6	14.1
HCC Total		**676.7**	**777.8**	**799.6**	**1,000.1**	**952.7**	**905.9**	**544.9**	**365.7**	**405.0**	**459.4**	**362.4**	**533.6**	**648.6**
ROR Total		**329.1**	**330.9**	**245.9**	**381.8**	**400.7**	**358.9**	**274.1**	**203.6**	**214.9**	**214.6**	**182.2**	**205.2**	**278.5**
Total		**1,005.8**	**1,108.7**	**1,045.5**	**1,381.9**	**1,353.3**	**1,264.8**	**819.0**	**569.3**	**619.9**	**674.0**	**544.6**	**738.8**	**927.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2015**	**2/2015**	**3/2015**	**4/2015**	**5/2015**	**6/2015**	**7/2015**	**8/2015**	**9/2015**	**10/2015**	**11/2015**	**12/2015**	**aMW**
Brownlee	HCC*	252.2	312.3	252.5	317.5	387.2	263.4	232.9	157.0	191.8	173.5	146.5	214.8	241.8
Oxbow	HCC	106.2	131.2	111.4	133.2	160.2	110.8	98.5	71.6	88.8	78.5	65.6	90.0	103.8
Hells Canyon	HCC	210.3	258.9	227.3	269.4	325.3	226.7	194.3	140.7	174.0	154.8	130.6	178.3	207.5
1000 Springs	ROR**	-	15.4	14.2	36.1	71.6	88.4	84.3	62.0	36.3	12.7	-	-	35.1
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	38.1	42.4	38.5	38.9	41.0	39.2	34.7	27.7	36.5	38.9	36.9	37.0	37.5
C .J. Strike	ROR	49.7	55.1	50.5	51.0	48.1	45.2	35.4	30.5	43.5	49.3	47.9	48.1	46.2
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	24.1	29.1	24.2	25.3	27.3	27.1	22.5	15.7	23.1	25.2	23.6	23.5	24.2
Milner	ROR	8.9	26.6	10.1	10.4	15.4	15.4	6.2	-	-	-	3.0	6.2	8.5
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	11.8	12.0	11.0
Swan Falls	ROR	16.2	17.9	16.5	17.3	16.1	15.2	12.6	10.7	14.7	16.2	15.8	15.8	15.4
Twin Falls	ROR	11.9	27.8	12.5	12.5	18.2	18.4	10.5	-	-	6.6	7.8	9.5	11.3
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	14.8	18.9	15.1	16.0	17.6	17.2	13.6	8.6	14.1	15.5	14.3	14.3	15.0
Upper Salmon 3&4	ROR	13.9	17.4	14.1	14.9	16.2	15.9	12.9	8.6	13.2	14.5	13.4	13.5	14.0
HCC Total		**568.7**	**702.4**	**591.2**	**720.1**	**872.6**	**600.9**	**525.7**	**369.3**	**454.5**	**406.8**	**342.7**	**483.1**	**553.2**
ROR Total		**217.2**	**291.1**	**236.7**	**263.1**	**314.2**	**328.2**	**279.0**	**210.4**	**224.0**	**219.2**	**202.3**	**207.7**	**249.4**
Total		**785.9**	**993.5**	**827.9**	**983.2**	**1,186.8**	**929.1**	**804.7**	**579.7**	**678.5**	**626.0**	**545.0**	**690.8**	**802.6**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2016**	**2/2016**	**3/2016**	**4/2016**	**5/2016**	**6/2016**	**7/2016**	**8/2016**	**9/2016**	**10/2016**	**11/2016**	**12/2016**	**aMW**
Brownlee	HCC*	252.7	316.9	254.5	321.2	391.9	265.6	232.6	156.8	190.9	173.3	146.8	214.6	243.1
Oxbow	HCC	106.4	133.1	112.3	134.7	162.1	111.8	98.4	71.5	88.4	78.4	65.8	89.9	104.4
Hells Canyon	HCC	210.6	262.6	229.0	272.3	329.0	228.6	194.1	140.6	173.3	154.7	130.9	178.1	208.6
1000 Springs	ROR**	-	18.0	14.1	36.7	71.6	88.5	84.5	62.4	37.1	12.9	-	-	35.5
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	38.0	43.1	38.8	39.0	41.4	39.2	34.6	27.6	36.4	38.8	36.7	36.9	37.5
C .J. Strike	ROR	49.8	57.3	50.8	51.2	48.8	45.1	35.4	30.4	43.3	49.2	47.8	48.1	46.4
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	24.2	30.9	24.8	25.3	27.4	26.9	22.4	15.6	23.0	25.1	23.5	23.5	24.4
Milner	ROR	8.9	30.6	11.9	10.8	15.4	15.4	6.2	-	-	-	3.0	6.2	9.0
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	11.8	12.0	11.0
Swan Falls	ROR	16.2	18.1	16.8	17.5	16.1	15.3	12.6	10.7	14.6	16.2	15.8	15.8	15.5
Twin Falls	ROR	12.2	31.2	14.6	13.2	18.2	18.8	10.5	-	-	6.6	7.8	9.5	11.9
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	14.9	19.2	15.6	16.1	17.6	17.1	13.6	8.6	13.9	15.4	14.2	14.3	15.0
Upper Salmon 3&4	ROR	13.9	17.7	14.5	14.9	16.3	15.8	12.8	8.5	13.1	14.4	13.4	13.4	14.1
HCC Total		**569.7**	**712.6**	**595.8**	**728.2**	**882.9**	**606.0**	**525.1**	**368.9**	**452.5**	**406.4**	**343.5**	**482.6**	**556.2**
ROR Total		**217.7**	**306.6**	**242.9**	**265.4**	**315.6**	**328.3**	**278.9**	**210.4**	**224.0**	**218.9**	**201.8**	**207.5**	**251.5**
Total		**787.4**	**1,019.2**	**838.7**	**993.6**	**1,198.5**	**934.3**	**804.0**	**579.3**	**676.5**	**625.3**	**545.3**	**690.1**	**807.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2017**	**2/2017**	**3/2017**	**4/2017**	**5/2017**	**6/2017**	**7/2017**	**8/2017**	**9/2017**	**10/2017**	**11/2017**	**12/2017**	**aMW**
Brownlee	HCC*	251.4	315.8	256.8	322.5	397.3	269.0	232.8	157.2	189.6	174.0	146.8	216.3	244.1
Oxbow	HCC	105.9	132.6	113.3	135.2	164.3	113.2	98.5	71.7	87.6	78.5	65.7	90.6	104.8
Hells Canyon	HCC	209.6	261.7	230.9	273.4	333.3	231.3	194.2	140.9	171.8	154.9	130.7	179.5	209.3
1000 Springs	ROR**	-	19.2	14.2	38.7	71.6	88.5	84.5	62.9	37.5	13.0	-	-	35.8
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	37.7	44.0	38.5	38.9	41.9	39.4	34.6	27.6	36.3	38.8	36.1	36.4	37.5
C .J. Strike	ROR	49.9	57.3	50.2	52.3	49.9	45.5	35.5	30.4	43.2	49.2	47.0	47.6	46.5
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.3	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	24.0	31.3	24.8	25.3	27.6	27.0	22.5	15.7	22.9	25.1	23.2	23.1	24.4
Milner	ROR	8.2	31.5	11.1	10.6	15.4	15.4	6.2	-	-	-	-	4.5	8.6
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	9.9	12.0	10.8
Swan Falls	ROR	16.2	18.5	16.4	17.6	16.5	15.4	12.6	10.7	14.6	16.2	15.5	15.7	15.5
Twin Falls	ROR	11.2	32.1	13.7	13.0	18.2	19.2	10.5	-	-	6.6	6.2	8.5	11.6
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	14.7	19.2	15.6	16.1	17.7	17.1	13.6	8.6	13.9	15.4	13.9	14.0	15.0
Upper Salmon 3&4	ROR	13.8	17.7	14.5	14.9	16.4	15.8	12.9	8.6	13.1	14.4	13.1	13.1	14.0
HCC Total		**566.9**	**710.1**	**601.0**	**731.1**	**894.8**	**613.5**	**525.5**	**369.8**	**448.9**	**407.4**	**343.2**	**486.4**	**558.2**
ROR Total		**215.3**	**311.3**	**240.0**	**268.1**	**318.0**	**329.5**	**279.2**	**211.1**	**224.2**	**219.0**	**192.7**	**202.7**	**250.9**
Total		**782.2**	**1,021.4**	**841.0**	**999.2**	**1,212.8**	**943.0**	**804.7**	**580.9**	**673.1**	**626.4**	**535.9**	**689.1**	**809.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2018**	**2/2018**	**3/2018**	**4/2018**	**5/2018**	**6/2018**	**7/2018**	**8/2018**	**9/2018**	**10/2018**	**11/2018**	**12/2018**	**aMW**
Brownlee	HCC*	251.4	315.7	256.4	323.3	399.7	268.5	232.5	156.9	189.0	174.4	146.6	215.6	244.2
Oxbow	HCC	105.9	132.6	113.1	135.5	165.2	113.0	98.3	71.6	87.3	78.7	65.6	90.3	104.8
Hells Canyon	HCC	209.6	261.7	230.6	274.0	335.1	230.9	194.0	140.6	171.1	155.2	130.5	178.9	209.3
1000 Springs	ROR**	-	19.1	14.0	39.4	72.1	88.6	84.6	63.1	37.8	14.2	-	-	36.1
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	37.6	43.0	38.4	39.5	42.4	39.4	34.5	27.5	36.2	38.7	36.1	36.1	37.5
C .J. Strike	ROR	49.9	57.0	49.5	52.4	49.9	45.4	35.4	30.3	43.0	49.1	46.9	47.2	46.3
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.4	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	24.0	31.2	24.1	25.4	27.5	26.9	22.4	15.6	22.8	25.0	23.1	22.8	24.2
Milner	ROR	8.2	31.3	9.6	10.7	15.4	15.4	6.2	-	-	-	-	3.8	8.4
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	9.9	12.0	10.8
Swan Falls	ROR	16.2	18.2	16.2	17.7	16.5	15.2	12.6	10.6	14.5	16.1	15.5	15.6	15.4
Twin Falls	ROR	11.6	31.8	12.2	13.5	18.2	19.2	10.5	-	-	6.6	6.2	8.1	11.5
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	14.8	19.2	15.1	16.1	17.7	17.0	13.6	8.5	13.8	15.4	13.9	13.8	14.9
Upper Salmon 3&4	ROR	13.8	17.7	14.1	15.0	16.4	15.8	12.8	8.5	13.0	14.3	13.1	13.0	14.0
HCC Total		**566.9**	**710.0**	**600.1**	**732.8**	**900.0**	**612.4**	**524.8**	**369.1**	**447.4**	**408.3**	**342.7**	**484.8**	**558.3**
ROR Total		**215.7**	**309.0**	**234.2**	**270.4**	**318.9**	**329.1**	**278.9**	**210.7**	**223.8**	**219.7**	**192.5**	**200.2**	**250.3**
Total		**782.6**	**1,019.0**	**834.3**	**1,003.2**	**1,218.8**	**941.5**	**803.7**	**579.8**	**671.1**	**628.0**	**535.2**	**685.0**	**808.5**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2019**	**2/2019**	**3/2019**	**4/2019**	**5/2019**	**6/2019**	**7/2019**	**8/2019**	**9/2019**	**10/2019**	**11/2019**	**12/2019**	**aMW**
Brownlee	HCC*	252.1	316.1	256.3	324.2	402.8	270.3	233.2	157.3	187.0	174.9	147.1	212.8	244.5
Oxbow	HCC	106.2	132.7	113.1	135.9	166.4	113.7	98.6	71.8	86.2	78.6	65.7	89.2	104.8
Hells Canyon	HCC	210.2	262.0	230.5	274.7	337.5	232.3	194.6	141.0	169.0	155.2	130.8	176.6	209.5
1000 Springs	ROR**	-	17.6	14.1	39.7	72.8	88.6	84.6	63.3	37.7	15.0	-	-	36.1
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	37.9	42.8	36.9	39.3	42.7	39.5	34.7	27.7	36.1	38.8	35.8	35.6	37.3
C .J. Strike	ROR	49.9	56.8	47.8	52.3	50.3	45.7	35.7	30.3	42.9	49.1	46.0	46.4	46.1
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.4	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	23.9	30.3	22.9	24.6	27.7	27.0	22.5	15.6	22.8	25.1	22.5	22.3	23.9
Milner	ROR	8.0	29.0	5.8	8.1	15.4	15.4	6.2	-	-	-	-	1.7	7.5
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	8.2	10.7	10.6
Swan Falls	ROR	16.1	17.8	15.8	17.7	16.7	15.4	12.6	10.6	14.5	16.1	15.4	15.4	15.3
Twin Falls	ROR	11.3	29.8	9.1	10.9	18.2	19.2	10.5	-	-	6.6	4.5	6.8	10.6
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	14.7	19.2	14.1	15.5	17.7	17.1	13.7	8.6	13.8	15.4	13.4	13.4	14.7
Upper Salmon 3&4	ROR	13.8	17.7	13.3	14.4	16.5	15.9	12.9	8.6	13.0	14.4	12.7	12.6	13.8
HCC Total		**568.5**	**710.8**	**599.9**	**734.8**	**906.6**	**616.3**	**526.4**	**370.1**	**442.1**	**408.7**	**343.6**	**478.6**	**558.9**
ROR Total		**215.2**	**301.5**	**220.8**	**263.2**	**320.8**	**330.0**	**279.7**	**211.3**	**223.5**	**220.8**	**186.3**	**192.7**	**247.2**
Total		**783.7**	**1,012.3**	**820.7**	**998.0**	**1,227.4**	**946.3**	**806.1**	**581.4**	**665.6**	**629.5**	**529.9**	**671.3**	**806.0**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2020**	**2/2020**	**3/2020**	**4/2020**	**5/2020**	**6/2020**	**7/2020**	**8/2020**	**9/2020**	**10/2020**	**11/2020**	**12/2020**	**aMW**
Brownlee	HCC*	251.1	315.3	256.2	323.3	401.8	269.0	232.6	156.7	184.5	175.0	147.2	210.1	243.6
Oxbow	HCC	105.7	132.4	113.0	135.5	166.1	113.2	98.4	71.4	84.9	78.5	65.7	88.0	104.4
Hells Canyon	HCC	209.3	261.3	230.4	274.0	336.8	231.3	194.1	140.4	166.6	155.0	130.7	174.3	208.7
1000 Springs	ROR**	-	15.6	14.0	39.5	72.7	88.6	84.6	63.2	37.7	15.0	-	-	35.9
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	37.5	42.1	36.7	39.1	42.5	39.3	34.6	27.5	35.9	38.6	35.5	35.5	37.1
C .J. Strike	ROR	49.1	54.6	47.5	52.1	50.1	45.4	35.4	30.1	42.6	48.8	45.7	46.2	45.6
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.4	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	23.5	29.3	22.6	24.4	27.6	26.9	22.4	15.5	22.5	24.9	22.5	22.2	23.7
Milner	ROR	7.7	26.8	5.2	7.8	15.4	15.4	6.2	-	-	-	-	1.9	7.2
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	6.9	6.7	10.5	8.2	10.9	10.6
Swan Falls	ROR	16.1	17.5	15.7	17.6	16.5	15.3	12.6	10.6	14.4	16.0	15.3	15.3	15.2
Twin Falls	ROR	11.1	27.9	8.6	10.6	18.2	19.2	10.5	-	-	6.6	4.5	7.0	10.4
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	14.4	19.0	13.9	15.3	17.7	17.0	13.6	8.4	13.6	15.3	13.4	13.3	14.6
Upper Salmon 3&4	ROR	13.5	17.5	13.1	14.3	16.4	15.8	12.8	8.4	12.8	14.3	12.7	12.6	13.7
HCC Total		**566.1**	**709.0**	**599.6**	**732.8**	**904.6**	**613.5**	**525.1**	**368.5**	**436.0**	**408.5**	**343.6**	**472.4**	**556.6**
ROR Total		**212.5**	**290.8**	**218.3**	**261.4**	**319.8**	**329.1**	**279.0**	**210.3**	**222.2**	**219.8**	**185.6**	**192.7**	**245.1**
Total		**778.6**	**999.8**	**817.9**	**994.2**	**1,224.4**	**942.6**	**804.1**	**578.8**	**658.1**	**628.3**	**529.2**	**665.1**	**801.8**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2021**	**2/2021**	**3/2021**	**4/2021**	**5/2021**	**6/2021**	**7/2021**	**8/2021**	**9/2021**	**10/2021**	**11/2021**	**12/2021**	**aMW**
Brownlee	HCC*	250.0	314.4	251.5	322.3	400.9	267.8	232.0	156.0	182.3	175.2	147.5	208.5	242.4
Oxbow	HCC	105.3	132.0	110.9	135.1	165.7	112.7	98.1	71.1	83.8	78.5	65.8	87.3	103.9
Hells Canyon	HCC	208.5	260.6	226.4	273.1	336.1	230.3	193.6	139.9	164.4	154.8	130.9	173.1	207.6
1000 Springs	ROR**	-	15.2	14.0	39.3	72.5	88.6	84.7	63.0	37.6	15.0	-	-	35.8
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	37.2	40.6	35.7	38.8	42.4	39.1	34.4	27.3	35.6	38.4	35.3	35.4	36.7
C .J. Strike	ROR	48.9	53.2	47.3	51.9	49.9	45.1	35.2	29.8	42.2	48.5	45.5	45.9	45.3
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.4	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	23.4	29.0	21.6	24.1	27.5	26.7	22.3	15.3	22.3	24.7	22.3	22.1	23.4
Milner	ROR	7.7	26.0	2.4	7.4	15.4	15.4	6.2	-	-	-	-	1.9	6.9
Shoshone Falls	ROR	12.0	12.0	10.2	12.0	12.0	12.0	12.0	6.9	6.7	10.5	8.2	10.9	10.5
Swan Falls	ROR	16.0	17.4	15.7	17.5	16.4	15.2	12.5	10.5	14.3	16.0	15.2	15.3	15.2
Twin Falls	ROR	10.4	27.3	6.4	10.2	18.2	19.2	10.5	-	-	6.6	4.5	7.0	10.0
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	14.3	18.8	13.1	15.1	17.7	16.9	13.5	8.3	13.4	15.1	13.3	13.2	14.4
Upper Salmon 3&4	ROR	13.4	17.3	12.4	14.2	16.4	15.6	12.7	8.3	12.7	14.1	12.6	12.5	13.5
HCC Total		**563.8**	**707.0**	**588.8**	**730.5**	**902.6**	**610.8**	**523.7**	**367.0**	**430.4**	**408.5**	**344.2**	**468.9**	**553.9**
ROR Total		**210.9**	**285.3**	**207.8**	**259.2**	**319.1**	**328.0**	**278.3**	**209.1**	**220.8**	**218.7**	**184.7**	**192.0**	**242.8**
Total		**774.7**	**992.3**	**796.6**	**989.7**	**1,221.7**	**938.8**	**802.0**	**576.1**	**651.2**	**627.2**	**528.9**	**660.9**	**796.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2022**	**2/2022**	**3/2022**	**4/2022**	**5/2022**	**6/2022**	**7/2022**	**8/2022**	**9/2022**	**10/2022**	**11/2022**	**12/2022**	**aMW**
Brownlee	HCC*	249.1	313.6	250.6	321.3	400.0	266.6	231.3	155.4	180.2	175.6	147.2	207.6	241.5
Oxbow	HCC	104.9	131.7	110.5	134.7	165.3	112.2	97.8	70.8	82.6	78.5	65.6	86.9	103.5
Hells Canyon	HCC	207.7	260.0	225.6	272.3	335.3	229.3	193.0	139.3	162.2	155.0	130.5	172.2	206.9
1000 Springs	ROR**	-	15.4	13.6	39.0	72.3	88.6	84.6	62.8	37.5	15.0	-	-	35.7
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	37.1	40.7	35.7	38.6	41.9	38.9	34.4	27.1	35.4	38.2	35.3	35.2	36.5
C .J. Strike	ROR	48.6	53.3	47.1	51.7	49.7	44.9	35.0	29.6	41.9	48.3	45.5	45.7	45.1
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.4	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	23.1	29.1	21.5	23.9	27.4	26.5	22.1	15.2	22.1	24.5	22.1	21.9	23.3
Milner	ROR	7.7	25.8	-	7.0	15.4	15.4	6.2	-	-	-	-	1.9	6.6
Shoshone Falls	ROR	12.0	12.0	9.5	12.0	12.0	12.0	12.0	6.9	6.7	10.5	8.2	10.9	10.4
Swan Falls	ROR	15.9	17.5	15.6	17.4	16.4	15.2	12.4	10.4	14.2	15.9	15.4	15.4	15.1
Twin Falls	ROR	10.4	27.4	5.8	9.9	18.2	19.2	10.5	-	-	6.6	4.5	7.0	10.0
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	14.0	18.8	13.1	15.0	17.6	16.7	13.4	8.2	13.3	15.0	13.1	13.1	14.3
Upper Salmon 3&4	ROR	13.2	17.3	12.4	14.0	16.3	15.5	12.6	8.2	12.6	14.0	12.4	12.4	13.4
HCC Total		**561.7**	**705.3**	**586.7**	**728.3**	**900.6**	**608.1**	**522.1**	**365.5**	**424.9**	**409.1**	**343.3**	**466.7**	**551.9**
ROR Total		**209.6**	**285.8**	**203.3**	**257.2**	**318.0**	**327.1**	**277.5**	**208.1**	**219.7**	**217.8**	**184.3**	**191.3**	**241.6**
Total		**771.3**	**991.1**	**790.0**	**985.5**	**1,218.5**	**935.2**	**799.6**	**573.6**	**644.6**	**626.9**	**527.6**	**658.0**	**793.5**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2023**	**2/2023**	**3/2023**	**4/2023**	**5/2023**	**6/2023**	**7/2023**	**8/2023**	**9/2023**	**10/2023**	**11/2023**	**12/2023**	**aMW**
Brownlee	HCC*	247.9	312.3	250.1	320.3	399.2	265.3	230.7	154.8	177.7	175.8	147.5	204.3	240.5
Oxbow	HCC	104.4	131.2	110.4	134.3	165.0	111.6	97.6	70.5	81.4	78.5	65.7	85.5	103.0
Hells Canyon	HCC	206.8	259.0	225.3	271.6	334.7	228.3	192.5	138.7	159.7	154.9	130.7	169.5	206.0
1000 Springs	ROR**	-	12.7	13.5	38.8	72.0	88.6	84.7	62.7	36.9	14.8	-	-	35.4
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	36.9	37.9	35.7	38.3	41.8	38.7	34.2	26.9	35.1	38.0	35.2	35.0	36.1
C .J. Strike	ROR	48.3	52.6	46.9	51.6	49.1	44.6	34.8	29.4	41.6	48.0	45.3	45.1	44.8
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.4	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	22.7	27.4	21.4	23.7	27.2	26.4	22.0	15.0	21.9	24.4	21.9	21.7	23.0
Milner	ROR	7.7	21.2	-	6.7	15.4	15.4	6.2	-	-	-	-	1.9	6.2
Shoshone Falls	ROR	12.0	12.0	9.5	12.0	12.0	12.0	12.0	6.9	6.7	10.5	8.2	10.9	10.4
Swan Falls	ROR	15.8	17.0	15.6	17.4	16.3	15.2	12.4	10.3	14.1	15.8	15.3	15.3	15.0
Twin Falls	ROR	10.4	23.3	5.8	9.8	18.2	19.2	10.5	-	-	6.6	4.5	7.0	9.6
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	13.8	17.5	13.0	14.8	17.5	16.6	13.3	8.1	13.1	14.9	13.0	12.9	14.0
Upper Salmon 3&4	ROR	13.0	16.2	12.3	13.9	16.2	15.4	12.5	8.1	12.4	13.9	12.3	12.3	13.2
HCC Total		**559.1**	**702.5**	**585.8**	**726.2**	**898.8**	**605.2**	**520.8**	**364.0**	**418.7**	**409.2**	**343.9**	**459.3**	**549.5**
ROR Total		**208.2**	**266.3**	**202.7**	**255.7**	**316.4**	**326.3**	**276.9**	**207.1**	**217.8**	**216.7**	**183.5**	**189.9**	**239.0**
Total		**767.3**	**968.8**	**788.5**	**981.9**	**1,215.2**	**931.5**	**797.7**	**571.1**	**636.5**	**625.9**	**527.4**	**649.2**	**788.4**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2024**	**2/2024**	**3/2024**	**4/2024**	**5/2024**	**6/2024**	**7/2024**	**8/2024**	**9/2024**	**10/2024**	**11/2024**	**12/2024**	**aMW**
Brownlee	HCC*	246.6	309.4	249.7	319.4	398.3	263.9	230.1	154.1	174.9	176.2	147.5	200.3	239.2
Oxbow	HCC	103.8	130.0	110.2	133.9	164.6	111.0	97.3	70.2	79.9	78.4	65.5	83.8	102.4
Hells Canyon	HCC	205.7	256.6	224.9	270.8	334.0	227.2	192.0	138.1	156.9	154.8	130.4	166.2	204.8
1000 Springs	ROR**	-	10.3	13.0	37.1	71.9	88.6	84.7	62.5	36.9	14.7	-	-	35.0
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	36.7	37.7	35.7	38.1	41.6	38.5	34.0	26.7	34.9	37.8	35.0	34.8	36.0
C .J. Strike	ROR	48.0	52.7	46.7	51.3	48.9	44.3	34.6	29.1	41.2	47.8	45.1	44.9	44.6
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.4	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	22.7	26.0	21.3	23.5	27.2	26.2	21.8	14.8	21.7	24.2	21.8	21.6	22.7
Milner	ROR	7.7	17.2	2.0	6.2	15.4	15.4	6.2	-	-	-	-	1.9	6.0
Shoshone Falls	ROR	12.0	12.0	9.7	12.0	12.0	12.0	12.0	6.9	6.7	10.5	8.2	10.7	10.4
Swan Falls	ROR	15.7	17.1	15.5	17.2	16.3	15.2	12.3	10.2	14.1	15.8	15.2	15.2	15.0
Twin Falls	ROR	10.4	20.2	6.0	9.5	18.2	19.2	10.5	-	-	6.6	4.5	6.8	9.3
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	13.7	16.5	12.9	14.7	17.5	16.5	13.1	8.0	12.9	14.8	12.9	12.8	13.9
Upper Salmon 3&4	ROR	13.0	15.3	12.2	13.8	16.1	15.3	12.4	8.0	12.3	13.8	12.2	12.2	13.1
HCC Total		**556.1**	**696.0**	**584.8**	**724.1**	**896.8**	**602.1**	**519.4**	**362.4**	**411.7**	**409.4**	**343.4**	**450.3**	**546.4**
ROR Total		**207.5**	**253.5**	**204.0**	**252.1**	**315.9**	**325.4**	**275.9**	**205.9**	**216.7**	**215.8**	**182.7**	**188.7**	**237.0**
Total		**763.6**	**949.5**	**788.8**	**976.2**	**1,212.7**	**927.5**	**795.3**	**568.3**	**628.3**	**625.2**	**526.1**	**639.0**	**783.4**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2025**	**2/2025**	**3/2025**	**4/2025**	**5/2025**	**6/2025**	**7/2025**	**8/2025**	**9/2025**	**10/2025**	**11/2025**	**12/2025**	**aMW**
Brownlee	HCC*	246.0	308.4	249.3	318.5	397.5	262.2	229.5	153.5	173.2	168.8	147.9	198.8	237.8
Oxbow	HCC	103.6	129.6	110.0	133.6	164.3	110.3	97.1	69.9	79.1	78.2	65.7	83.1	102.0
Hells Canyon	HCC	205.2	255.9	224.5	270.2	333.4	225.8	191.5	137.6	155.3	154.0	130.7	164.9	204.1
1000 Springs	ROR**	-	9.0	11.9	37.0	71.8	88.6	84.6	62.2	36.3	14.6	-	-	34.7
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	36.6	37.6	35.2	37.9	41.5	38.3	33.9	26.5	34.6	37.7	34.8	34.5	35.8
C .J. Strike	ROR	47.4	50.7	46.5	51.1	48.7	44.1	34.4	28.9	40.9	47.6	44.7	44.9	44.2
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.4	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	22.6	25.1	21.3	23.4	27.1	26.0	21.7	14.7	21.4	24.1	21.6	21.4	22.5
Milner	ROR	7.7	14.8	2.1	5.9	15.4	15.4	6.2	-	-	-	-	1.7	5.8
Shoshone Falls	ROR	12.0	12.0	9.8	12.0	12.0	12.0	12.0	6.9	6.7	10.5	8.2	10.5	10.4
Swan Falls	ROR	15.6	16.1	15.4	17.2	16.2	15.1	12.2	10.2	14.1	15.7	15.2	15.2	14.9
Twin Falls	ROR	10.4	18.2	6.1	9.3	18.2	19.2	10.5	-	-	6.6	4.5	6.6	9.1
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	13.7	15.8	12.9	14.6	17.4	16.4	13.0	7.8	12.8	14.6	12.8	12.7	13.7
Upper Salmon 3&4	ROR	12.9	14.7	12.2	13.7	16.1	15.2	12.4	7.9	12.1	13.7	12.1	12.0	12.9
HCC Total		**554.8**	**693.9**	**583.8**	**722.3**	**895.1**	**598.3**	**518.1**	**361.0**	**407.5**	**401.0**	**344.3**	**446.8**	**543.9**
ROR Total		**206.5**	**242.5**	**202.4**	**250.8**	**315.1**	**324.5**	**275.2**	**204.8**	**214.9**	**214.9**	**181.7**	**187.3**	**235.1**
Total		**761.3**	**936.4**	**786.2**	**973.1**	**1,210.2**	**922.8**	**793.3**	**565.8**	**622.4**	**615.9**	**526.0**	**634.1**	**779.0**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2026**	**2/2026**	**3/2026**	**4/2026**	**5/2026**	**6/2026**	**7/2026**	**8/2026**	**9/2026**	**10/2026**	**11/2026**	**12/2026**	**aMW**
Brownlee	HCC*	245.3	306.0	248.8	317.7	396.7	261.4	228.9	152.8	171.5	168.8	147.9	198.4	237.0
Oxbow	HCC	103.3	128.6	109.8	133.2	164.0	110.0	96.8	69.6	78.2	78.2	65.6	83.0	101.7
Hells Canyon	HCC	204.6	253.9	224.1	269.5	332.8	225.1	191.0	137.0	153.6	153.9	130.6	164.6	203.4
1000 Springs	ROR**	-	7.4	11.2	35.9	71.7	88.6	84.6	62.0	35.9	14.5	-	-	34.3
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	36.4	37.2	34.6	37.7	41.4	38.1	33.7	26.3	34.4	37.5	34.6	34.2	35.5
C .J. Strike	ROR	47.2	49.3	46.3	50.9	48.2	43.7	34.2	28.6	40.7	47.4	44.6	44.6	43.8
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.4	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	22.5	22.7	21.1	22.5	27.0	25.8	21.6	14.5	21.2	23.9	21.5	21.3	22.1
Milner	ROR	7.7	10.7	2.0	5.2	15.4	15.4	6.2	-	-	-	-	1.8	5.4
Shoshone Falls	ROR	12.0	12.0	9.7	12.0	12.0	12.0	12.0	6.9	6.7	10.5	8.2	10.5	10.4
Swan Falls	ROR	15.6	16.0	15.3	17.1	16.0	14.9	12.1	10.1	14.0	15.6	15.1	15.1	14.7
Twin Falls	ROR	10.4	12.6	6.0	8.5	18.2	18.8	10.5	-	-	6.6	4.5	6.7	8.6
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	13.6	13.9	12.7	13.9	17.3	16.2	12.9	7.7	12.6	14.5	12.6	12.6	13.4
Upper Salmon 3&4	ROR	12.8	13.1	12.1	13.1	16.0	15.1	12.3	7.8	12.0	13.6	12.0	11.9	12.7
HCC Total		**553.2**	**688.5**	**582.7**	**720.4**	**893.5**	**596.5**	**516.7**	**359.4**	**403.2**	**400.9**	**344.1**	**446.0**	**542.1**
ROR Total		**205.8**	**223.4**	**200.0**	**245.5**	**313.9**	**322.8**	**274.4**	**203.6**	**213.5**	**213.9**	**180.9**	**186.5**	**232.0**
Total		**759.0**	**911.9**	**782.7**	**965.9**	**1,207.4**	**919.3**	**791.1**	**563.0**	**616.7**	**614.8**	**525.0**	**632.5**	**774.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2027**	**2/2027**	**3/2027**	**4/2027**	**5/2027**	**6/2027**	**7/2027**	**8/2027**	**9/2027**	**10/2027**	**11/2027**	**12/2027**	**aMW**
Brownlee	HCC*	244.3	301.9	248.3	316.9	395.9	260.6	228.3	152.2	169.6	169.1	147.9	197.8	236.1
Oxbow	HCC	102.9	126.9	109.5	132.9	163.7	109.7	96.6	69.3	77.2	78.2	65.6	82.7	101.3
Hells Canyon	HCC	203.8	250.6	223.7	268.9	332.2	224.5	190.5	136.4	151.7	153.9	130.6	164.1	202.6
1000 Springs	ROR**	-	-	11.1	34.8	71.7	88.6	84.7	61.8	35.2	14.3	-	-	33.5
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	36.3	37.0	34.5	37.5	41.2	37.9	33.6	26.1	34.1	37.4	34.2	34.0	35.3
C .J. Strike	ROR	47.0	48.6	45.8	50.7	48.1	43.6	34.0	28.4	40.3	47.1	44.4	44.5	43.5
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.4	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	22.4	22.7	20.9	22.5	26.9	25.7	21.4	14.4	21.0	23.8	21.3	21.1	22.0
Milner	ROR	7.7	8.2	1.7	4.9	15.4	15.4	6.2	-	-	-	-	1.7	5.1
Shoshone Falls	ROR	12.0	12.0	9.7	12.0	12.0	12.0	12.0	6.9	6.7	10.5	8.2	10.4	10.4
Swan Falls	ROR	15.5	15.8	15.4	17.0	16.0	14.8	12.1	10.0	13.9	15.5	15.0	15.0	14.7
Twin Falls	ROR	10.4	11.6	6.0	8.5	18.2	18.8	10.5	-	-	6.6	4.5	6.6	8.5
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	13.5	13.9	12.6	13.8	17.2	16.1	12.8	7.6	12.4	14.4	12.5	12.4	13.3
Upper Salmon 3&4	ROR	12.7	13.1	12.0	13.0	16.0	15.0	12.2	7.7	11.8	13.6	11.9	11.8	12.6
HCC Total		**551.0**	**679.4**	**581.5**	**718.7**	**891.8**	**594.8**	**515.4**	**357.9**	**398.4**	**401.2**	**344.1**	**444.6**	**539.9**
ROR Total		**205.1**	**211.4**	**198.7**	**243.4**	**313.4**	**322.1**	**273.8**	**202.6**	**211.4**	**213.0**	**179.8**	**185.3**	**230.0**
Total		**756.1**	**890.8**	**780.2**	**962.1**	**1,205.2**	**916.9**	**789.2**	**560.5**	**609.8**	**614.2**	**523.9**	**629.9**	**769.9**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2028**	**2/2028**	**3/2028**	**4/2028**	**5/2028**	**6/2028**	**7/2028**	**8/2028**	**9/2028**	**10/2028**	**11/2028**	**12/2028**	**aMW**
Brownlee	HCC*	243.3	299.7	247.9	316.0	395.2	259.9	227.7	151.6	167.3	169.6	148.0	196.7	235.2
Oxbow	HCC	102.4	126.0	109.4	132.5	163.4	109.4	96.3	69.0	76.1	78.3	65.6	82.3	100.9
Hells Canyon	HCC	202.9	248.8	223.3	268.2	331.6	223.9	190.0	135.9	149.4	154.1	130.6	163.2	201.8
1000 Springs	ROR**	-	-	11.0	36.0	71.7	88.6	84.7	61.5	34.9	14.2	-	-	33.5
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	36.2	36.7	34.3	37.3	41.0	37.7	33.4	26.0	33.9	37.2	34.0	34.0	35.1
C .J. Strike	ROR	46.8	48.4	45.4	50.6	47.9	43.5	33.8	28.1	40.0	46.9	44.2	44.3	43.3
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.4	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	22.3	22.5	20.8	22.4	26.8	25.5	21.3	14.2	20.8	23.7	20.9	20.9	21.8
Milner	ROR	7.6	8.2	-	4.7	15.4	15.4	6.2	-	-	-	-	1.7	4.9
Shoshone Falls	ROR	12.0	12.0	8.8	12.0	12.0	12.0	12.0	6.9	6.7	10.5	8.2	10.1	10.3
Swan Falls	ROR	15.4	15.7	15.4	16.9	16.0	14.8	12.0	9.9	13.8	15.5	15.0	15.0	14.6
Twin Falls	ROR	10.4	11.6	5.2	8.4	18.2	18.8	10.5	-	-	6.6	4.5	6.3	8.4
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	13.4	13.7	12.5	13.8	17.2	16.0	12.7	7.5	12.3	14.3	12.2	12.3	13.2
Upper Salmon 3&4	ROR	12.7	12.9	11.9	13.0	15.9	14.9	12.1	7.6	11.7	13.4	11.7	11.7	12.5
HCC Total		**548.6**	**674.5**	**580.6**	**716.7**	**890.1**	**593.2**	**514.0**	**356.5**	**392.7**	**402.0**	**344.2**	**442.2**	**537.9**
ROR Total		**204.4**	**210.2**	**194.3**	**243.8**	**312.8**	**321.4**	**273.0**	**201.4**	**210.1**	**212.1**	**178.5**	**184.1**	**228.8**
Total		**753.0**	**884.7**	**774.9**	**960.5**	**1,202.9**	**914.6**	**787.0**	**557.9**	**602.8**	**614.1**	**522.7**	**626.3**	**766.8**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2029**	**2/2029**	**3/2029**	**4/2029**	**5/2029**	**6/2029**	**7/2029**	**8/2029**	**9/2029**	**10/2029**	**11/2029**	**12/2029**	**aMW**
Brownlee	HCC*	242.7	298.5	247.5	315.1	394.4	259.1	227.1	151.1	161.7	169.4	148.1	196.1	234.2
Oxbow	HCC	102.2	125.5	109.2	132.2	163.1	109.0	96.1	68.8	75.1	78.1	65.6	82.0	100.6
Hells Canyon	HCC	202.5	247.9	223.0	267.5	331.0	223.3	189.6	135.5	147.4	153.7	130.6	162.7	201.2
1000 Springs	ROR**	-	-	10.7	34.9	71.7	88.6	84.7	61.4	34.8	14.1	-	-	33.4
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	36.1	36.1	34.2	36.6	40.9	37.5	33.3	25.8	33.6	37.0	33.8	33.8	34.9
C .J. Strike	ROR	46.6	48.2	45.3	50.4	47.8	43.2	33.6	27.8	39.7	46.6	44.0	44.0	43.1
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.4	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	22.1	22.0	20.7	21.7	26.7	25.3	21.2	14.0	20.6	23.5	20.8	20.7	21.6
Milner	ROR	7.6	8.0	-	4.5	15.4	15.3	6.2	-	-	-	-	1.6	4.9
Shoshone Falls	ROR	12.0	12.0	8.8	12.0	12.0	12.0	12.0	6.9	6.7	10.5	8.2	9.7	10.2
Swan Falls	ROR	15.3	15.6	15.3	16.8	16.0	14.7	11.9	9.8	13.7	15.5	14.9	14.9	14.5
Twin Falls	ROR	10.4	11.3	5.2	8.4	18.2	18.8	10.5	-	-	6.6	4.5	6.0	8.3
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	13.3	13.4	12.4	13.2	17.1	15.8	12.6	7.3	12.1	14.2	12.1	12.1	13.0
Upper Salmon 3&4	ROR	12.6	12.6	11.8	12.5	15.8	14.7	12.0	7.5	11.6	13.3	11.5	11.6	12.3
HCC Total		**547.4**	**671.9**	**579.7**	**714.8**	**888.4**	**591.4**	**512.8**	**355.4**	**384.1**	**401.2**	**344.3**	**440.8**	**536.0**
ROR Total		**203.6**	**207.7**	**193.4**	**239.7**	**312.3**	**320.1**	**272.3**	**200.2**	**208.8**	**211.1**	**177.6**	**182.2**	**227.4**
Total		**751.0**	**879.6**	**773.1**	**954.5**	**1,200.7**	**911.5**	**785.1**	**555.6**	**592.9**	**612.3**	**521.9**	**623.0**	**763.4**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2030**	**2/2030**	**3/2030**	**4/2030**	**5/2030**	**6/2030**	**7/2030**	**8/2030**	**9/2030**	**10/2030**	**11/2030**	**12/2030**	**aMW**
Brownlee	HCC*	242.1	297.7	247.0	314.3	393.6	258.4	226.5	151.0	159.8	169.5	148.2	195.0	233.6
Oxbow	HCC	101.9	125.2	109.0	131.9	162.8	108.7	95.8	68.8	74.1	78.1	65.6	81.5	100.3
Hells Canyon	HCC	202.0	247.2	222.6	266.8	330.4	222.7	189.0	135.4	145.5	153.7	130.7	161.8	200.6
1000 Springs	ROR**	-	-	10.4	34.7	71.6	88.5	84.7	61.4	34.8	14.2	-	-	33.4
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	35.8	35.9	34.1	35.7	40.8	37.3	33.1	25.6	33.4	36.8	33.6	33.5	34.6
C .J. Strike	ROR	46.2	47.9	45.1	49.0	47.6	42.9	33.3	27.6	39.4	46.4	43.7	43.9	42.8
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.4	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	22.0	21.9	20.6	21.3	26.6	25.1	21.0	13.9	20.4	23.3	20.7	20.6	21.5
Milner	ROR	7.3	8.0	-	3.1	15.4	15.0	6.2	-	-	-	-	1.6	4.7
Shoshone Falls	ROR	12.0	12.0	9.5	11.3	12.0	12.0	12.0	6.9	6.7	10.5	8.2	9.7	10.2
Swan Falls	ROR	15.2	15.6	15.3	16.5	15.9	14.6	11.9	9.8	13.6	15.4	14.9	14.8	14.5
Twin Falls	ROR	10.3	11.3	5.8	7.3	18.1	18.6	10.5	-	-	6.6	4.5	6.0	8.3
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	13.2	13.3	12.4	12.9	17.0	15.7	12.5	7.2	11.9	14.1	12.0	12.0	12.9
Upper Salmon 3&4	ROR	12.5	12.5	11.8	12.3	15.8	14.6	11.9	7.4	11.4	13.2	11.5	11.5	12.2
HCC Total		**546.0**	**670.1**	**578.6**	**713.0**	**886.8**	**589.8**	**511.3**	**355.2**	**379.3**	**401.3**	**344.5**	**438.3**	**534.5**
ROR Total		**202.1**	**206.9**	**194.0**	**232.8**	**311.6**	**318.5**	**271.4**	**199.5**	**207.6**	**210.3**	**176.9**	**181.4**	**226.1**
Total		**748.1**	**877.0**	**772.6**	**945.8**	**1,198.3**	**908.3**	**782.7**	**554.7**	**586.9**	**611.6**	**521.4**	**619.7**	**760.6**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2031**	**2/2031**	**3/2031**	**4/2031**	**5/2031**	**6/2031**	**7/2031**	**8/2031**	**9/2031**	**10/2031**	**11/2031**	**12/2031**	**aMW**
Brownlee	HCC*	241.3	297.0	246.6	313.4	392.9	257.7	225.9	150.7	157.7	169.7	148.2	193.7	232.9
Oxbow	HCC	101.6	124.9	108.8	131.5	162.5	108.4	95.5	68.7	72.9	78.0	65.6	81.0	99.9
Hells Canyon	HCC	201.3	246.7	222.3	266.1	329.7	222.1	188.5	135.2	143.3	153.6	130.6	160.7	200.0
1000 Springs	ROR**	-	-	10.2	33.2	71.6	88.5	84.7	61.4	34.6	14.1	-	-	33.2
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	35.6	35.6	34.0	35.6	40.7	37.1	33.0	25.4	33.1	36.6	33.6	33.4	34.5
C .J. Strike	ROR	46.0	47.6	44.9	47.8	47.5	42.5	33.2	27.4	39.1	46.1	43.5	43.6	42.4
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.4	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	21.8	21.7	20.5	21.1	26.5	24.9	20.9	13.7	20.2	23.2	20.5	20.4	21.3
Milner	ROR	7.3	8.0	-	2.0	15.3	14.8	6.2	-	-	-	-	1.6	4.6
Shoshone Falls	ROR	12.0	12.0	9.2	10.2	12.0	12.0	12.0	6.9	6.7	10.5	8.2	9.7	10.1
Swan Falls	ROR	15.4	15.5	15.2	16.4	15.9	14.5	11.8	9.7	13.5	15.3	14.8	14.8	14.4
Twin Falls	ROR	10.3	10.7	5.5	6.4	17.9	18.6	10.5	-	-	6.6	4.5	6.0	8.1
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	13.1	13.1	12.3	12.8	16.9	15.5	12.4	7.1	11.8	13.9	11.9	11.9	12.7
Upper Salmon 3&4	ROR	12.4	12.4	11.7	12.1	15.7	14.4	11.8	7.3	11.3	13.1	11.4	11.4	12.1
HCC Total		**544.2**	**668.6**	**577.7**	**711.0**	**885.0**	**588.2**	**509.9**	**354.6**	**373.9**	**401.3**	**344.4**	**435.4**	**532.8**
ROR Total		**201.5**	**205.1**	**192.5**	**226.3**	**310.8**	**317.0**	**270.8**	**198.6**	**206.3**	**209.2**	**176.2**	**180.6**	**224.6**
Total		**745.7**	**873.7**	**770.2**	**937.3**	**1,195.8**	**905.2**	**780.7**	**553.2**	**580.1**	**610.5**	**520.6**	**616.0**	**757.4**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2032**	**2/2032**	**3/2032**	**4/2032**	**5/2032**	**6/2032**	**7/2032**	**8/2032**	**9/2032**	**10/2032**	**11/2032**	**12/2032**	**aMW**
Brownlee	HCC*	240.7	296.2	245.9	312.6	392.1	256.8	225.3	150.1	155.7	169.9	148.2	193.1	232.2
Oxbow	HCC	101.3	124.6	108.5	131.2	162.2	108.1	95.3	68.4	71.9	78.0	65.6	80.7	99.6
Hells Canyon	HCC	200.8	246.1	221.6	265.5	329.2	221.4	188.0	134.6	141.4	153.5	130.5	160.2	199.4
1000 Springs	ROR**	-	-	9.9	33.1	71.6	88.5	84.6	61.4	34.5	14.1	-	-	33.1
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	35.4	35.4	33.9	35.5	40.6	36.9	32.9	25.2	32.9	36.4	33.4	33.2	34.3
C .J. Strike	ROR	45.7	47.1	44.6	47.6	47.4	42.4	33.0	27.1	38.8	45.9	43.3	43.2	42.2
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.4	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	21.7	21.6	20.4	20.9	26.4	24.7	20.8	13.6	19.9	23.0	20.3	20.3	21.1
Milner	ROR	7.3	7.8	-	-	15.0	14.5	6.2	-	-	-	-	1.6	4.4
Shoshone Falls	ROR	12.0	12.0	8.9	9.4	12.0	12.0	12.0	6.9	6.7	10.5	8.2	9.6	10.0
Swan Falls	ROR	15.3	15.4	15.2	16.3	15.9	14.5	11.8	9.7	13.4	15.2	14.7	14.7	14.3
Twin Falls	ROR	10.3	10.6	5.3	5.7	17.9	18.3	10.5	-	-	6.6	4.5	5.9	8.0
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	12.9	13.0	12.2	12.6	16.8	15.3	12.3	7.0	11.6	13.8	11.8	11.8	12.6
Upper Salmon 3&4	ROR	12.3	12.3	11.6	12.0	15.6	14.3	11.7	7.2	11.1	13.0	11.3	11.3	12.0
HCC Total		**542.8**	**666.9**	**576.0**	**709.3**	**883.4**	**586.3**	**508.6**	**353.1**	**369.0**	**401.4**	**344.3**	**434.0**	**531.3**
ROR Total		**200.5**	**203.7**	**191.0**	**221.8**	**309.9**	**315.6**	**270.1**	**197.8**	**204.9**	**208.3**	**175.3**	**179.4**	**223.2**
Total		**743.3**	**870.6**	**767.0**	**931.1**	**1,193.3**	**901.9**	**778.7**	**550.9**	**573.8**	**609.7**	**519.6**	**613.4**	**754.4**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2033**	**2/2033**	**3/2033**	**4/2033**	**5/2033**	**6/2033**	**7/2033**	**8/2033**	**9/2033**	**10/2033**	**11/2033**	**12/2033**	**aMW**
Brownlee	HCC*	240.1	295.5	243.7	311.7	391.6	256.0	224.7	149.5	153.8	169.7	148.7	192.4	231.4
Oxbow	HCC	101.1	124.3	107.6	130.8	162.0	107.7	95.0	68.1	70.9	77.8	65.7	80.4	99.3
Hells Canyon	HCC	200.3	245.5	219.8	264.8	328.7	220.7	187.5	134.1	139.5	153.2	130.8	159.6	198.7
1000 Springs	ROR**	-	-	9.0	33.1	71.6	88.5	84.7	61.4	34.5	14.0	-	-	33.1
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	35.3	35.2	33.8	35.3	40.5	36.7	32.8	25.0	32.6	36.2	33.2	33.0	34.1
C .J. Strike	ROR	45.0	46.6	44.4	47.4	47.2	42.3	32.8	26.9	38.5	45.7	43.2	42.6	41.9
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.4	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	21.6	21.5	20.3	20.7	26.3	24.5	20.6	13.4	19.7	22.8	20.2	20.1	21.0
Milner	ROR	7.3	7.8	-	-	14.3	14.2	6.2	-	-	-	-	1.6	4.3
Shoshone Falls	ROR	12.0	12.0	8.6	8.8	12.0	12.0	12.0	6.9	6.7	10.5	8.2	9.6	9.9
Swan Falls	ROR	15.2	15.3	15.1	16.3	15.8	14.4	11.7	9.6	13.3	15.4	14.6	14.5	14.3
Twin Falls	ROR	10.3	10.6	4.8	5.2	17.7	18.2	10.5	-	-	6.6	4.5	5.9	7.9
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	12.8	12.9	12.1	12.5	16.8	15.2	12.2	6.9	11.4	13.7	11.6	11.7	12.5
Upper Salmon 3&4	ROR	12.2	12.2	11.6	11.9	15.6	14.2	11.6	7.1	11.0	12.9	11.2	11.2	11.9
HCC Total		**541.5**	**665.3**	**571.1**	**707.3**	**882.2**	**584.4**	**507.2**	**351.7**	**364.2**	**400.7**	**345.2**	**432.4**	**529.4**
ROR Total		**199.3**	**202.6**	**188.7**	**219.9**	**308.5**	**314.4**	**269.4**	**196.9**	**203.7**	**207.6**	**174.5**	**178.0**	**222.0**
Total		**740.8**	**867.9**	**759.8**	**927.2**	**1,190.7**	**898.8**	**776.6**	**548.6**	**567.8**	**608.3**	**519.7**	**610.4**	**751.4**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2034**	**2/2034**	**3/2034**	**4/2034**	**5/2034**	**6/2034**	**7/2034**	**8/2034**	**9/2034**	**10/2034**	**11/2034**	**12/2034**	**aMW**
Brownlee	HCC*	240.1	294.7	242.8	310.9	391.1	255.1	224.1	148.9	151.9	169.8	148.4	192.2	230.8
Oxbow	HCC	101.1	123.9	107.1	130.5	161.8	107.3	94.8	67.8	69.9	77.8	65.6	80.3	99.0
Hells Canyon	HCC	200.3	244.9	219.0	264.1	328.3	220.0	187.1	133.5	137.6	153.1	130.5	159.4	198.1
1000 Springs	ROR**	-	-	8.6	33.1	71.6	88.3	84.6	61.3	34.5	14.0	-	-	33.0
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	34.9	35.0	33.6	35.2	40.4	36.5	32.6	24.8	32.4	36.0	32.8	32.8	33.9
C .J. Strike	ROR	44.1	45.2	44.2	47.2	47.1	42.0	32.6	26.7	38.2	45.5	43.0	42.2	41.5
Cascade	ROR	1.5	1.4	1.3	1.2	2.1	7.0	7.4	12.1	7.4	1.5	1.3	1.4	3.8
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	21.4	21.3	20.1	20.5	26.2	24.3	20.5	13.2	19.5	22.7	19.9	19.9	20.8
Milner	ROR	7.3	7.5	-	-	14.3	14.2	6.2	-	-	-	-	1.6	4.3
Shoshone Falls	ROR	12.0	12.0	8.5	8.6	12.0	12.0	12.0	6.9	6.7	10.5	8.2	9.6	9.9
Swan Falls	ROR	15.0	15.3	15.0	16.2	15.7	14.4	11.6	9.5	13.2	15.3	14.6	14.4	14.2
Twin Falls	ROR	10.3	10.5	4.7	4.8	17.7	18.2	10.5	-	-	6.6	4.5	5.9	7.8
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	12.7	12.8	12.0	12.3	16.7	15.0	12.1	6.7	11.3	13.5	11.4	11.5	12.3
Upper Salmon 3&4	ROR	12.1	12.1	11.5	11.8	15.5	14.1	11.5	7.0	10.8	12.8	11.0	11.0	11.8
HCC Total		**541.5**	**663.5**	**568.9**	**705.5**	**881.1**	**582.4**	**506.0**	**350.2**	**359.4**	**400.7**	**344.5**	**431.9**	**528.0**
ROR Total		**197.4**	**200.2**	**187.2**	**218.4**	**307.9**	**313.2**	**268.5**	**195.8**	**202.6**	**206.7**	**173.2**	**176.7**	**220.7**
Total		**738.9**	**863.7**	**756.1**	**923.9**	**1,189.0**	**895.6**	**774.5**	**546.0**	**561.9**	**607.4**	**517.7**	**608.6**	**748.6**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2015**	**2/2015**	**3/2015**	**4/2015**	**5/2015**	**6/2015**	**7/2015**	**8/2015**	**9/2015**	**10/2015**	**11/2015**	**12/2015**	**aMW**
Brownlee	HCC*	211.6	197.2	238.9	253.6	272.2	204.3	218.2	144.1	157.4	153.8	149.0	191.1	199.3
Oxbow	HCC	88.6	82.8	99.9	105.6	112.7	84.2	91.9	65.5	73.1	70.5	65.7	79.6	85.0
Hells Canyon	HCC	175.1	164.8	202.4	214.2	231.3	169.8	180.6	128.8	143.1	139.2	130.4	157.4	169.8
1000 Springs	ROR**	0.0	0.0	0.0	29.8	70.5	86.4	85.4	56.2	28.0	9.4	0.0	0.0	30.5
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	34.7	35.0	33.4	32.5	38.0	36.7	33.5	26.6	35.2	37.7	35.6	35.4	34.5
C .J. Strike	ROR	44.1	43.7	43.5	41.2	42.5	39.4	31.3	29.0	39.0	44.9	44.5	44.0	40.6
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	22.3	22.6	20.6	20.0	25.5	24.4	21.8	15.0	22.0	24.1	22.9	22.7	22.0
Milner	ROR	6.0	6.1	0.0	0.0	12.8	12.7	6.2	0.0	0.0	0.0	0.0	4.9	4.1
Shoshone Falls	ROR	12.0	12.0	7.6	4.5	12.0	12.0	12.0	6.5	6.5	9.2	10.7	12.0	9.8
Swan Falls	ROR	14.9	14.8	14.8	14.2	14.7	14.0	11.4	10.2	13.8	15.2	15.2	15.0	14.0
Twin Falls	ROR	9.3	9.3	4.0	0.0	15.9	16.4	10.1	0.0	0.0	5.5	6.8	8.9	7.2
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	13.4	13.8	12.3	11.9	16.1	15.1	13.1	8.1	13.2	14.7	13.8	13.7	13.3
Upper Salmon 3&4	ROR	12.7	13.0	11.7	11.4	15.0	14.1	12.4	8.1	12.5	13.7	13.0	12.9	12.5
HCC Total		**475.3**	**444.8**	**541.2**	**573.4**	**616.1**	**458.3**	**490.7**	**338.4**	**373.6**	**363.5**	**345.1**	**428.1**	**454.0**
ROR Total		**196.9**	**198.8**	**176.9**	**194.3**	**293.2**	**302.6**	**271.1**	**197.6**	**205.2**	**204.1**	**190.3**	**197.2**	**219.0**
Total		**672.2**	**643.6**	**718.1**	**767.7**	**909.3**	**760.9**	**761.8**	**536.0**	**578.8**	**567.6**	**535.4**	**625.3**	**673.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2016**	**2/2016**	**3/2016**	**4/2016**	**5/2016**	**6/2016**	**7/2016**	**8/2016**	**9/2016**	**10/2016**	**11/2016**	**12/2016**	**aMW**
Brownlee	HCC*	211.3	200.1	238.7	253.8	275.8	203.8	218.0	143.7	156.5	154.1	149.1	190.8	199.6
Oxbow	HCC	88.4	84.1	99.8	105.7	114.2	84.0	91.8	65.3	72.7	70.7	65.7	79.5	85.2
Hells Canyon	HCC	174.8	167.2	202.3	214.4	234.2	169.5	180.4	128.4	142.3	139.4	130.5	157.1	170.0
1000 Springs	ROR**	0.0	0.0	0.0	29.7	70.5	86.7	85.6	56.9	28.9	9.3	0.0	0.0	30.6
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	34.7	35.0	33.4	32.8	38.0	36.6	33.4	26.5	35.0	37.7	35.4	35.3	34.5
C .J. Strike	ROR	44.0	43.5	43.5	41.1	42.5	39.3	31.2	28.9	38.8	44.9	44.4	43.9	40.5
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	22.2	22.5	20.5	19.9	25.4	24.3	21.8	14.9	21.9	24.1	22.8	22.6	21.9
Milner	ROR	6.1	7.1	0.0	0.0	12.8	12.7	6.2	0.0	0.0	0.0	0.0	4.9	4.2
Shoshone Falls	ROR	12.0	12.0	7.6	4.5	12.0	12.0	12.0	6.5	6.5	9.8	11.1	12.0	9.8
Swan Falls	ROR	14.9	14.8	14.8	14.2	14.8	14.0	11.4	10.2	13.8	15.2	15.2	15.0	14.0
Twin Falls	ROR	9.3	9.9	4.0	0.0	15.9	16.4	10.1	0.0	0.0	6.0	7.2	8.9	7.3
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	13.3	13.7	12.3	11.9	16.1	15.0	13.1	8.0	13.1	14.6	13.7	13.6	13.2
Upper Salmon 3&4	ROR	12.6	13.0	11.7	11.4	15.0	14.1	12.4	8.1	12.4	13.7	12.9	12.9	12.5
HCC Total		**474.5**	**451.4**	**540.8**	**573.9**	**624.1**	**457.3**	**490.2**	**337.4**	**371.4**	**364.2**	**345.3**	**427.4**	**454.8**
ROR Total		**196.6**	**200.0**	**176.8**	**194.3**	**293.2**	**302.5**	**271.1**	**197.9**	**205.4**	**205.0**	**190.5**	**196.8**	**219.2**
Total		**671.1**	**651.4**	**717.6**	**768.2**	**917.3**	**759.8**	**761.3**	**535.3**	**576.7**	**569.2**	**535.8**	**624.2**	**674.0**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2017**	**2/2017**	**3/2017**	**4/2017**	**5/2017**	**6/2017**	**7/2017**	**8/2017**	**9/2017**	**10/2017**	**11/2017**	**12/2017**	**aMW**
Brownlee	HCC*	210.7	201.0	236.8	257.8	280.9	204.0	218.4	143.7	155.6	154.3	149.6	189.2	200.2
Oxbow	HCC	88.2	84.4	99.0	107.3	114.6	84.1	92.0	65.3	72.2	70.6	65.9	78.8	85.2
Hells Canyon	HCC	174.3	167.9	200.7	217.6	234.1	169.6	180.7	128.4	141.3	139.3	130.8	155.9	170.0
1000 Springs	ROR**	0.0	0.0	0.0	29.9	70.7	86.7	85.7	57.1	30.1	9.4	0.0	0.0	30.8
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	34.3	34.7	33.2	33.2	38.3	36.6	33.4	26.5	34.9	37.6	34.8	34.7	34.4
C .J. Strike	ROR	43.7	43.3	43.5	41.4	43.5	39.6	31.4	29.0	38.8	44.9	44.1	43.2	40.5
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	22.1	22.3	20.4	20.0	25.5	24.3	21.8	14.9	21.9	24.1	22.3	22.1	21.8
Milner	ROR	5.0	7.0	0.0	0.0	12.8	12.7	6.2	0.0	0.0	0.0	0.0	3.8	4.0
Shoshone Falls	ROR	12.0	12.0	7.3	4.5	12.0	12.0	12.0	6.5	6.5	10.0	9.8	12.0	9.7
Swan Falls	ROR	14.8	14.7	14.8	14.2	15.1	14.1	11.5	10.2	13.8	15.2	15.0	14.8	14.0
Twin Falls	ROR	8.7	9.8	3.8	0.0	15.9	16.4	10.1	0.0	0.0	6.2	6.1	8.3	7.1
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	13.2	13.5	12.2	11.9	16.2	15.0	13.1	8.0	13.1	14.6	13.3	13.2	13.1
Upper Salmon 3&4	ROR	12.5	12.8	11.6	11.4	15.0	14.1	12.4	8.1	12.4	13.7	12.5	12.5	12.4
HCC Total		**473.2**	**453.3**	**536.5**	**582.7**	**629.5**	**457.7**	**491.1**	**337.4**	**369.0**	**364.2**	**346.3**	**423.9**	**455.4**
ROR Total		**193.8**	**198.6**	**175.8**	**195.3**	**295.2**	**302.9**	**271.5**	**198.2**	**206.5**	**205.4**	**185.7**	**192.3**	**218.4**
Total		**667.0**	**651.9**	**712.3**	**778.0**	**924.7**	**760.6**	**762.6**	**535.6**	**575.5**	**569.6**	**532.0**	**616.2**	**673.8**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2018**	**2/2018**	**3/2018**	**4/2018**	**5/2018**	**6/2018**	**7/2018**	**8/2018**	**9/2018**	**10/2018**	**11/2018**	**12/2018**	**aMW**
Brownlee	HCC*	209.6	202.7	236.0	258.1	281.9	203.7	218.1	143.4	154.5	154.1	149.5	188.5	200.0
Oxbow	HCC	87.7	85.2	98.7	107.4	115.0	84.0	91.9	65.1	71.6	70.5	65.8	78.5	85.1
Hells Canyon	HCC	173.4	169.3	200.0	217.8	234.9	169.4	180.5	128.1	140.3	139.1	130.7	155.3	169.9
1000 Springs	ROR**	0.0	0.0	0.0	29.8	70.8	86.8	85.7	57.2	30.4	10.3	0.0	0.0	30.9
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	34.2	34.6	33.3	33.0	38.3	36.5	33.4	26.4	34.8	37.6	34.8	34.5	34.3
C .J. Strike	ROR	43.6	43.2	43.5	41.1	43.6	39.6	31.3	28.9	38.6	44.8	44.0	42.8	40.4
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	22.1	22.2	20.4	20.0	25.5	24.3	21.7	14.8	21.7	24.0	22.2	21.8	21.7
Milner	ROR	5.0	7.0	0.0	0.0	12.8	12.7	6.2	0.0	0.0	0.0	0.0	3.2	3.9
Shoshone Falls	ROR	12.0	12.0	7.3	4.5	12.0	12.0	12.0	6.5	6.5	10.0	9.8	11.8	9.7
Swan Falls	ROR	14.8	14.7	14.8	14.4	15.1	14.0	11.4	10.1	13.7	15.1	15.0	14.7	14.0
Twin Falls	ROR	8.7	9.8	3.8	0.0	16.0	16.8	10.1	0.0	0.0	6.2	6.1	7.8	7.1
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	13.3	13.5	12.2	11.9	16.2	15.0	13.0	8.0	13.0	14.6	13.2	13.0	13.1
Upper Salmon 3&4	ROR	12.5	12.7	11.6	11.4	15.0	14.0	12.4	8.0	12.3	13.7	12.5	12.3	12.4
HCC Total		**470.7**	**457.2**	**534.7**	**583.3**	**631.8**	**457.1**	**490.5**	**336.6**	**366.3**	**363.7**	**346.0**	**422.3**	**455.0**
ROR Total		**193.7**	**198.2**	**175.9**	**194.9**	**295.5**	**303.1**	**271.1**	**197.8**	**206.0**	**206.0**	**185.4**	**189.6**	**218.1**
Total		**664.4**	**655.4**	**710.6**	**778.2**	**927.2**	**760.2**	**761.6**	**534.4**	**572.3**	**569.7**	**531.4**	**611.9**	**673.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2019**	**2/2019**	**3/2019**	**4/2019**	**5/2019**	**6/2019**	**7/2019**	**8/2019**	**9/2019**	**10/2019**	**11/2019**	**12/2019**	**aMW**
Brownlee	HCC*	209.6	205.5	232.5	257.6	283.9	204.5	218.9	143.3	153.6	154.6	149.9	180.0	199.5
Oxbow	HCC	87.7	86.4	97.2	107.2	115.8	84.2	92.2	65.1	71.1	70.6	65.9	78.0	85.1
Hells Canyon	HCC	173.4	171.6	197.2	217.4	236.5	170.0	181.1	128.0	139.3	139.3	130.9	153.8	169.9
1000 Springs	ROR**	0.0	0.0	8.0	29.6	70.6	86.9	85.6	57.3	30.6	11.2	0.0	0.0	31.7
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	34.1	34.6	33.4	32.8	38.6	36.7	33.3	26.5	34.7	37.6	34.4	33.9	34.2
C .J. Strike	ROR	43.4	43.2	43.8	41.2	43.9	39.8	31.6	28.9	38.6	44.9	43.6	42.2	40.4
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	22.1	22.2	20.5	20.1	25.7	24.4	21.7	14.9	21.5	24.1	21.5	21.3	21.7
Milner	ROR	5.0	6.8	0.0	0.0	12.8	12.7	6.2	0.0	0.0	0.0	0.0	0.0	3.6
Shoshone Falls	ROR	12.0	12.0	7.3	4.0	12.0	12.0	12.0	6.5	6.5	10.0	8.2	9.6	9.3
Swan Falls	ROR	14.8	14.7	14.9	14.3	15.2	14.1	11.5	10.2	13.7	15.2	14.8	14.4	14.0
Twin Falls	ROR	8.6	9.6	3.8	0.0	15.9	16.4	10.1	0.0	0.0	6.2	4.5	5.9	6.8
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	13.2	13.5	12.3	12.0	16.3	15.1	13.0	8.0	12.8	14.6	12.7	12.6	13.0
Upper Salmon 3&4	ROR	12.5	12.7	11.7	11.5	15.2	14.1	12.4	8.1	12.2	13.7	12.0	12.0	12.3
HCC Total		**470.7**	**463.5**	**526.9**	**582.2**	**636.2**	**458.7**	**492.2**	**336.4**	**364.0**	**364.5**	**346.7**	**411.8**	**454.5**
ROR Total		**193.2**	**197.8**	**184.7**	**194.3**	**296.4**	**303.6**	**271.3**	**198.3**	**205.6**	**207.2**	**179.5**	**179.6**	**217.6**
Total		**663.9**	**661.3**	**711.6**	**776.5**	**932.6**	**762.3**	**763.5**	**534.7**	**569.6**	**571.7**	**526.2**	**591.4**	**672.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2020**	**2/2020**	**3/2020**	**4/2020**	**5/2020**	**6/2020**	**7/2020**	**8/2020**	**9/2020**	**10/2020**	**11/2020**	**12/2020**	**aMW**
Brownlee	HCC*	208.9	200.8	232.5	256.6	283.2	203.7	218.3	142.6	151.9	154.7	149.4	180.0	198.6
Oxbow	HCC	87.4	84.4	97.2	106.8	115.6	83.9	92.0	64.8	70.2	70.6	65.7	77.9	84.7
Hells Canyon	HCC	172.8	167.8	197.2	216.7	235.9	169.4	180.6	127.4	137.6	139.2	130.4	153.8	169.1
1000 Springs	ROR**	0.0	0.0	8.0	29.6	70.6	86.8	85.6	57.0	30.2	11.0	0.0	0.0	31.6
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	33.9	34.4	33.4	32.6	38.4	36.5	33.1	26.3	34.4	37.4	34.3	33.8	34.0
C .J. Strike	ROR	43.2	43.2	43.6	41.1	43.2	39.5	31.4	28.7	38.4	44.8	43.4	42.3	40.2
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	22.0	22.1	20.4	20.0	25.6	24.2	21.6	14.8	21.2	23.9	21.4	21.3	21.5
Milner	ROR	5.0	6.8	0.0	0.0	12.8	12.7	6.2	0.0	0.0	0.0	0.0	0.0	3.6
Shoshone Falls	ROR	12.0	12.0	7.3	4.0	12.0	12.0	12.0	6.5	6.5	10.0	8.2	9.6	9.3
Swan Falls	ROR	14.7	14.7	14.8	14.3	14.9	14.0	11.5	10.1	13.7	15.1	14.8	14.5	13.9
Twin Falls	ROR	8.6	9.6	3.8	0.0	15.9	16.4	10.1	0.0	0.0	6.2	4.5	5.9	6.8
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	13.2	13.4	12.2	11.9	16.2	14.9	12.9	7.9	12.6	14.5	12.6	12.6	12.9
Upper Salmon 3&4	ROR	12.5	12.7	11.7	11.4	15.1	14.0	12.3	8.0	12.0	13.6	12.0	11.9	12.3
HCC Total		**469.1**	**453.0**	**526.9**	**580.1**	**634.6**	**457.0**	**490.9**	**334.8**	**359.7**	**364.5**	**345.5**	**411.7**	**452.3**
ROR Total		**192.6**	**197.4**	**184.2**	**193.7**	**294.9**	**302.4**	**270.6**	**197.2**	**204.0**	**206.2**	**179.0**	**179.6**	**216.8**
Total		**661.7**	**650.4**	**711.1**	**773.8**	**929.5**	**759.4**	**761.5**	**532.0**	**563.6**	**570.7**	**524.5**	**591.3**	**669.1**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2021**	**2/2021**	**3/2021**	**4/2021**	**5/2021**	**6/2021**	**7/2021**	**8/2021**	**9/2021**	**10/2021**	**11/2021**	**12/2021**	**aMW**
Brownlee	HCC*	208.3	196.1	230.3	256.2	282.5	202.9	217.6	141.9	149.7	154.7	149.5	179.7	197.4
Oxbow	HCC	87.1	82.4	96.3	106.6	115.3	83.6	91.7	64.4	69.0	70.4	65.7	77.8	84.2
Hells Canyon	HCC	172.3	163.9	195.5	216.3	235.3	168.8	180.1	126.8	135.4	139.0	130.4	153.5	168.1
1000 Springs	ROR**	0.0	0.0	8.0	29.6	70.6	86.6	85.5	56.9	29.8	10.9	0.0	0.0	31.5
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	33.8	34.3	33.2	32.5	38.3	36.3	33.0	26.1	34.2	37.2	34.2	33.6	33.9
C .J. Strike	ROR	42.8	42.8	43.5	41.0	43.0	39.2	31.1	28.5	38.3	44.6	43.3	42.0	40.0
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	21.6	21.9	20.3	19.9	25.5	24.0	21.5	14.6	21.0	23.8	21.2	21.1	21.4
Milner	ROR	5.0	6.1	0.0	0.0	12.8	12.7	6.2	0.0	0.0	0.0	0.0	0.0	3.6
Shoshone Falls	ROR	12.0	12.0	7.3	4.0	12.0	12.0	12.0	6.5	6.5	9.8	8.2	9.6	9.3
Swan Falls	ROR	14.7	14.6	14.8	14.2	14.9	13.9	11.4	10.0	13.6	15.1	14.7	14.4	13.9
Twin Falls	ROR	8.6	9.4	3.8	0.0	15.9	16.4	10.1	0.0	0.0	6.0	4.5	5.9	6.7
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	12.9	13.2	12.1	11.9	16.2	14.8	12.9	7.8	12.4	14.4	12.5	12.4	12.8
Upper Salmon 3&4	ROR	12.2	12.5	11.6	11.3	15.0	13.9	12.2	7.9	11.8	13.5	11.9	11.8	12.1
HCC Total		**467.7**	**442.4**	**522.1**	**579.1**	**633.0**	**455.3**	**489.4**	**333.1**	**354.0**	**364.1**	**345.6**	**411.0**	**449.7**
ROR Total		**191.1**	**195.3**	**183.6**	**193.2**	**294.4**	**301.2**	**269.8**	**196.2**	**202.6**	**205.0**	**178.3**	**178.5**	**215.8**
Total		**658.8**	**637.7**	**705.7**	**772.3**	**927.4**	**756.5**	**759.2**	**529.3**	**556.6**	**569.1**	**523.9**	**589.5**	**665.5**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2022**	**2/2022**	**3/2022**	**4/2022**	**5/2022**	**6/2022**	**7/2022**	**8/2022**	**9/2022**	**10/2022**	**11/2022**	**12/2022**	**aMW**
Brownlee	HCC*	207.6	194.1	229.4	255.7	281.8	202.5	217.0	141.2	147.4	154.8	149.6	179.3	196.7
Oxbow	HCC	86.9	81.5	95.9	106.4	115.0	83.4	91.4	64.1	67.9	70.4	65.7	77.6	83.8
Hells Canyon	HCC	171.8	162.3	194.7	215.9	234.8	168.4	179.5	126.2	133.2	138.8	130.5	153.2	167.4
1000 Springs	ROR**	0.0	0.0	8.0	29.5	70.6	86.5	85.5	56.5	29.6	10.9	0.0	0.0	31.4
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	33.6	34.1	33.0	32.5	38.2	36.1	32.9	25.9	33.9	37.0	34.0	33.4	33.7
C .J. Strike	ROR	42.5	42.5	42.5	40.9	42.8	38.9	30.9	28.2	38.1	44.3	43.1	41.8	39.7
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	21.4	21.7	20.2	19.8	25.4	23.9	21.4	14.4	20.8	23.7	21.1	20.9	21.2
Milner	ROR	5.0	5.9	0.0	0.0	12.8	12.7	6.2	0.0	0.0	0.0	0.0	0.0	3.6
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.5	6.5	9.6	8.2	9.6	9.3
Swan Falls	ROR	14.6	14.5	14.5	14.1	14.8	13.8	11.2	9.9	13.6	15.0	14.6	14.3	13.7
Twin Falls	ROR	8.6	9.3	3.8	0.0	15.9	16.4	10.1	0.0	0.0	5.8	4.5	5.9	6.7
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	12.7	13.1	12.1	11.8	16.1	14.7	12.8	7.6	12.2	14.3	12.3	12.3	12.7
Upper Salmon 3&4	ROR	12.1	12.4	11.5	11.3	15.0	13.8	12.1	7.8	11.7	13.4	11.8	11.7	12.1
HCC Total		**466.3**	**437.9**	**520.0**	**578.0**	**631.5**	**454.3**	**487.9**	**331.5**	**348.4**	**364.0**	**345.8**	**410.1**	**448.0**
ROR Total		**190.0**	**194.0**	**181.9**	**192.6**	**293.8**	**300.2**	**269.0**	**194.7**	**201.4**	**203.7**	**177.4**	**177.6**	**214.7**
Total		**656.3**	**631.9**	**701.9**	**770.6**	**925.3**	**754.5**	**756.9**	**526.2**	**549.8**	**567.7**	**523.2**	**587.7**	**662.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2023**	**2/2023**	**3/2023**	**4/2023**	**5/2023**	**6/2023**	**7/2023**	**8/2023**	**9/2023**	**10/2023**	**11/2023**	**12/2023**	**aMW**
Brownlee	HCC*	206.9	193.5	228.5	255.3	281.2	202.0	216.4	140.6	145.3	154.5	149.9	178.7	196.1
Oxbow	HCC	86.6	81.3	95.6	106.3	114.7	83.2	91.1	63.8	66.7	70.1	65.8	77.3	83.5
Hells Canyon	HCC	171.2	161.8	194.0	215.6	234.3	168.0	179.0	125.6	131.0	138.4	130.7	152.6	166.8
1000 Springs	ROR**	0.0	0.0	8.0	29.6	70.5	86.5	85.5	56.2	29.0	10.6	0.0	0.0	31.3
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	33.4	33.9	32.9	32.4	38.1	35.9	32.8	25.7	33.7	36.8	33.8	33.2	33.6
C .J. Strike	ROR	42.3	42.3	42.2	40.9	42.7	38.5	30.7	28.0	38.0	44.1	42.8	41.5	39.5
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	21.3	21.5	20.1	19.7	25.3	23.7	21.2	14.3	20.6	23.4	20.9	20.8	21.1
Milner	ROR	5.0	5.4	0.0	0.0	12.8	12.7	6.2	0.0	0.0	0.0	0.0	0.0	3.5
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.5	6.5	8.8	8.2	9.6	9.2
Swan Falls	ROR	14.5	14.4	14.4	14.1	14.8	13.7	11.2	9.9	13.5	14.9	14.5	14.2	13.7
Twin Falls	ROR	8.6	8.9	3.8	0.0	15.9	16.4	10.1	0.0	0.0	5.2	4.5	5.9	6.6
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	12.6	13.0	12.0	11.7	16.0	14.6	12.6	7.5	12.1	14.1	12.2	12.2	12.6
Upper Salmon 3&4	ROR	12.0	12.3	11.5	11.2	14.9	13.7	12.0	7.7	11.5	13.3	11.6	11.6	11.9
HCC Total		**464.7**	**436.6**	**518.1**	**577.2**	**630.1**	**453.2**	**486.5**	**330.0**	**342.9**	**363.0**	**346.4**	**408.6**	**446.4**
ROR Total		**189.2**	**192.2**	**181.2**	**192.3**	**293.2**	**299.1**	**268.2**	**193.7**	**199.9**	**200.9**	**176.3**	**176.7**	**213.6**
Total		**653.9**	**628.8**	**699.3**	**769.5**	**923.3**	**752.3**	**754.7**	**523.7**	**542.8**	**563.9**	**522.7**	**585.3**	**660.0**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2024**	**2/2024**	**3/2024**	**4/2024**	**5/2024**	**6/2024**	**7/2024**	**8/2024**	**9/2024**	**10/2024**	**11/2024**	**12/2024**	**aMW**
Brownlee	HCC*	206.3	192.8	227.9	254.8	280.4	201.6	215.5	139.9	143.7	154.5	149.7	179.1	195.5
Oxbow	HCC	86.3	81.0	95.3	106.1	114.4	83.1	90.8	63.5	65.9	70.1	65.7	77.5	83.3
Hells Canyon	HCC	170.7	161.2	193.5	215.2	233.7	167.7	178.4	125.0	129.5	138.4	130.5	153.0	166.4
1000 Springs	ROR**	0.0	0.0	8.0	29.6	70.2	86.5	85.6	56.2	28.5	10.3	0.0	0.0	31.2
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	33.3	33.8	32.8	32.4	37.9	35.7	32.6	25.5	33.4	36.5	33.6	33.0	33.4
C .J. Strike	ROR	42.0	41.9	42.0	40.7	42.5	38.3	30.5	27.7	37.7	43.8	42.5	41.2	39.2
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	21.1	21.3	20.1	19.6	25.1	23.5	21.0	14.1	20.3	23.2	20.7	20.5	20.9
Milner	ROR	4.9	6.0	0.0	0.0	12.8	12.7	6.2	0.0	0.0	0.0	0.0	0.0	3.6
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.5	6.5	8.8	8.2	9.6	9.2
Swan Falls	ROR	14.4	14.4	14.3	14.0	14.8	13.6	11.1	9.8	13.4	14.8	14.4	14.1	13.6
Twin Falls	ROR	8.6	9.2	3.8	0.0	15.9	16.4	10.1	0.0	0.0	5.2	4.5	5.9	6.6
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	12.5	12.8	12.0	11.6	15.9	14.4	12.5	7.4	11.9	13.9	12.1	12.0	12.4
Upper Salmon 3&4	ROR	11.9	12.2	11.4	11.1	14.8	13.5	11.9	7.6	11.4	13.1	11.5	11.5	11.8
HCC Total		**463.3**	**435.0**	**516.7**	**576.1**	**628.5**	**452.4**	**484.7**	**328.4**	**339.0**	**363.0**	**345.9**	**409.6**	**445.2**
ROR Total		**188.2**	**192.1**	**180.7**	**191.7**	**292.1**	**298.0**	**267.4**	**192.7**	**198.1**	**199.3**	**175.3**	**175.5**	**212.6**
Total		**651.5**	**627.1**	**697.4**	**767.8**	**920.6**	**750.4**	**752.1**	**521.1**	**537.1**	**562.3**	**521.2**	**585.1**	**657.8**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2025**	**2/2025**	**3/2025**	**4/2025**	**5/2025**	**6/2025**	**7/2025**	**8/2025**	**9/2025**	**10/2025**	**11/2025**	**12/2025**	**aMW**
Brownlee	HCC*	204.8	192.1	227.4	254.4	275.8	201.3	215.0	139.3	142.1	154.1	150.2	178.5	194.6
Oxbow	HCC	85.7	80.7	95.1	105.9	114.2	82.9	90.6	63.2	65.1	69.8	65.9	77.3	83.0
Hells Canyon	HCC	169.5	160.6	193.1	214.8	234.2	167.5	177.9	124.4	127.9	137.8	130.9	152.5	165.9
1000 Springs	ROR**	0.0	0.0	8.0	29.5	69.8	85.9	85.6	56.2	28.3	10.5	0.0	0.0	31.1
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	33.2	33.7	32.7	32.3	37.3	35.4	32.4	25.3	33.1	36.4	33.4	32.8	33.2
C .J. Strike	ROR	41.7	41.8	42.0	40.6	42.0	37.3	30.4	27.5	37.4	43.5	42.3	41.0	39.0
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	21.0	21.2	20.0	19.5	24.9	23.3	20.9	13.9	20.1	23.0	20.5	20.4	20.7
Milner	ROR	4.8	6.0	0.0	0.0	11.3	11.2	6.2	0.0	0.0	0.0	0.0	0.0	3.3
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.5	6.5	8.8	8.2	9.6	9.2
Swan Falls	ROR	14.4	14.3	14.3	14.0	14.7	13.3	11.0	9.7	13.3	14.8	14.4	14.1	13.5
Twin Falls	ROR	8.5	9.2	3.8	0.0	14.0	15.0	10.1	0.0	0.0	5.2	4.5	5.9	6.4
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	12.4	12.7	11.9	11.5	15.7	14.2	12.4	7.3	11.7	13.8	11.9	11.9	12.3
Upper Salmon 3&4	ROR	11.8	12.1	11.4	11.1	14.6	13.4	11.8	7.5	11.2	13.0	11.4	11.4	11.7
HCC Total		**460.0**	**433.4**	**515.6**	**575.1**	**624.1**	**451.7**	**483.5**	**326.9**	**335.0**	**361.7**	**347.0**	**408.3**	**443.5**
ROR Total		**187.3**	**191.5**	**180.4**	**191.2**	**286.5**	**292.4**	**266.7**	**191.8**	**196.6**	**198.7**	**174.4**	**174.8**	**211.0**
Total		**647.3**	**624.9**	**696.0**	**766.3**	**910.5**	**744.1**	**750.2**	**518.7**	**531.6**	**560.4**	**521.4**	**583.1**	**654.5**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2026**	**2/2026**	**3/2026**	**4/2026**	**5/2026**	**6/2026**	**7/2026**	**8/2026**	**9/2026**	**10/2026**	**11/2026**	**12/2026**	**aMW**
Brownlee	HCC*	203.8	191.5	226.9	254.0	275.2	201.0	214.3	138.5	140.0	154.2	150.2	177.9	194.0
Oxbow	HCC	85.3	80.4	94.9	105.7	113.9	82.8	90.3	62.9	64.1	69.8	65.9	77.0	82.7
Hells Canyon	HCC	168.7	160.1	192.6	214.5	233.7	167.2	177.4	123.8	125.9	137.8	130.8	152.0	165.4
1000 Springs	ROR**	0.0	0.0	7.9	29.4	69.6	85.5	85.5	56.2	28.2	10.4	0.0	0.0	31.1
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	33.1	33.5	32.6	32.3	37.1	35.1	32.3	25.1	32.8	36.2	33.2	32.8	33.0
C .J. Strike	ROR	41.5	41.7	41.8	40.4	41.8	36.5	30.4	27.3	37.1	43.3	42.0	40.8	38.7
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	20.8	21.0	19.9	19.3	24.3	23.1	20.7	13.8	19.9	22.9	20.4	20.2	20.5
Milner	ROR	5.0	6.0	0.0	0.0	10.5	10.4	6.2	0.0	0.0	0.0	0.0	0.0	3.2
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.5	6.5	8.8	8.2	9.6	9.2
Swan Falls	ROR	14.2	14.3	14.3	13.9	14.7	13.1	11.0	9.7	13.2	14.8	14.3	14.1	13.5
Twin Falls	ROR	8.6	9.2	3.8	0.0	13.3	14.3	10.1	0.0	0.0	5.2	4.5	5.9	6.2
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	12.3	12.6	11.8	11.4	15.3	14.1	12.3	7.2	11.5	13.7	11.8	11.8	12.2
Upper Salmon 3&4	ROR	11.7	12.0	11.3	11.0	14.3	13.3	11.7	7.4	11.1	12.9	11.3	11.3	11.6
HCC Total		**457.8**	**432.0**	**514.4**	**574.2**	**622.7**	**451.0**	**482.0**	**325.2**	**330.0**	**361.8**	**346.9**	**406.9**	**442.1**
ROR Total		**186.7**	**190.8**	**179.7**	**190.4**	**283.1**	**288.8**	**266.1**	**191.1**	**195.3**	**197.9**	**173.5**	**174.2**	**209.8**
Total		**644.5**	**622.8**	**694.1**	**764.6**	**905.8**	**739.8**	**748.1**	**516.3**	**525.2**	**559.7**	**520.4**	**581.1**	**651.9**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2027**	**2/2027**	**3/2027**	**4/2027**	**5/2027**	**6/2027**	**7/2027**	**8/2027**	**9/2027**	**10/2027**	**11/2027**	**12/2027**	**aMW**
Brownlee	HCC*	203.1	190.1	225.7	253.5	274.6	200.7	213.7	137.8	138.1	154.3	149.9	177.6	193.3
Oxbow	HCC	85.0	79.9	94.4	105.5	113.7	82.7	90.0	62.5	63.0	69.7	65.7	76.8	82.4
Hells Canyon	HCC	168.1	159.0	191.7	214.1	233.2	167.0	176.9	123.1	124.0	137.7	130.5	151.7	164.7
1000 Springs	ROR**	0.0	0.0	7.9	29.4	69.4	85.6	85.5	56.2	27.8	10.2	0.0	0.0	31.0
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	33.0	33.3	32.5	32.2	37.0	34.8	32.0	24.9	32.5	36.0	33.1	32.6	32.8
C .J. Strike	ROR	41.2	41.3	42.0	40.2	41.7	36.2	30.3	27.0	36.8	43.1	41.7	40.4	38.5
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	20.7	20.8	19.9	19.2	24.2	23.1	20.5	13.6	19.6	22.7	20.2	20.1	20.4
Milner	ROR	5.0	5.1	0.0	0.0	10.5	10.4	6.2	0.0	0.0	0.0	0.0	0.0	3.1
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.5	6.5	8.8	8.2	9.6	9.2
Swan Falls	ROR	14.2	14.1	14.3	13.8	14.7	13.0	10.9	9.6	13.1	14.8	14.2	14.0	13.4
Twin Falls	ROR	8.6	8.5	3.8	0.0	13.3	14.3	10.1	0.0	0.0	5.2	4.5	5.9	6.2
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	12.2	12.4	11.8	11.3	15.2	14.1	12.1	7.0	11.4	13.6	11.7	11.7	12.0
Upper Salmon 3&4	ROR	11.6	11.8	11.3	10.9	14.2	13.2	11.6	7.2	10.9	12.8	11.2	11.2	11.5
HCC Total		**456.2**	**429.0**	**511.8**	**573.1**	**621.5**	**450.4**	**480.6**	**323.4**	**325.0**	**361.7**	**346.1**	**406.1**	**440.4**
ROR Total		**186.0**	**187.8**	**179.8**	**189.7**	**282.4**	**288.1**	**265.1**	**189.9**	**193.6**	**196.9**	**172.6**	**173.2**	**208.8**
Total		**642.2**	**616.8**	**691.6**	**762.8**	**903.9**	**738.5**	**745.7**	**513.3**	**518.6**	**558.6**	**518.7**	**579.3**	**649.2**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2028**	**2/2028**	**3/2028**	**4/2028**	**5/2028**	**6/2028**	**7/2028**	**8/2028**	**9/2028**	**10/2028**	**11/2028**	**12/2028**	**aMW**
Brownlee	HCC*	202.5	190.4	224.7	253.1	274.0	200.4	213.3	137.2	135.5	154.2	150.4	176.4	192.7
Oxbow	HCC	84.7	80.0	94.0	105.3	113.4	82.6	89.8	62.2	61.7	69.6	65.9	76.3	82.1
Hells Canyon	HCC	167.6	159.3	190.9	213.8	232.7	166.7	176.5	122.6	121.5	137.3	130.9	150.7	164.2
1000 Springs	ROR**	0.0	0.0	7.9	29.4	69.5	85.6	85.6	56.2	27.3	10.4	0.0	0.0	31.0
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	32.9	33.0	32.4	32.1	37.0	34.6	31.8	24.8	32.2	35.8	32.6	32.4	32.6
C .J. Strike	ROR	40.9	41.1	41.8	40.0	41.6	36.0	30.2	26.8	36.4	43.0	41.5	40.2	38.3
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	20.5	20.7	19.7	19.1	24.1	23.0	20.4	13.5	19.4	22.5	20.0	20.0	20.2
Milner	ROR	5.0	5.2	0.0	0.0	10.5	10.4	6.2	0.0	0.0	0.0	0.0	0.0	3.1
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.5	6.5	8.7	8.2	9.2	9.2
Swan Falls	ROR	14.2	14.1	14.3	13.8	14.7	12.9	10.8	9.5	13.0	14.7	14.1	14.0	13.3
Twin Falls	ROR	8.5	8.5	3.8	0.0	13.3	14.3	10.1	0.0	0.0	4.8	4.5	5.5	6.1
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	12.1	12.3	11.6	11.2	15.1	14.0	12.0	6.9	11.2	13.4	11.5	11.6	11.9
Upper Salmon 3&4	ROR	11.5	11.8	11.2	10.8	14.1	13.2	11.5	7.1	10.8	12.7	11.1	11.1	11.4
HCC Total		**454.8**	**429.7**	**509.6**	**572.2**	**620.1**	**449.7**	**479.6**	**322.0**	**318.7**	**361.1**	**347.2**	**403.4**	**439.0**
ROR Total		**185.1**	**187.2**	**179.0**	**189.1**	**282.1**	**287.4**	**264.5**	**189.2**	**191.8**	**195.7**	**171.3**	**171.7**	**207.8**
Total		**639.9**	**616.9**	**688.6**	**761.3**	**902.2**	**737.1**	**744.1**	**511.2**	**510.4**	**556.8**	**518.5**	**575.1**	**646.8**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2029**	**2/2029**	**3/2029**	**4/2029**	**5/2029**	**6/2029**	**7/2029**	**8/2029**	**9/2029**	**10/2029**	**11/2029**	**12/2029**	**aMW**
Brownlee	HCC*	201.9	189.8	223.8	252.7	273.4	200.1	212.7	136.6	133.5	154.3	150.2	175.6	192.0
Oxbow	HCC	84.5	79.7	93.6	105.2	113.2	82.4	89.6	62.0	60.7	69.5	65.7	75.9	81.8
Hells Canyon	HCC	167.1	158.7	190.2	213.5	232.3	166.5	176.0	122.0	119.5	137.3	130.6	150.0	163.6
1000 Springs	ROR**	0.0	0.0	7.8	29.4	69.1	84.8	85.5	56.1	26.6	10.3	0.0	0.0	30.8
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	32.9	32.7	32.3	32.0	36.2	34.0	31.7	24.6	32.0	35.6	32.5	32.1	32.4
C .J. Strike	ROR	40.9	40.9	41.8	39.8	41.4	35.5	30.1	26.5	36.1	42.9	41.2	40.0	38.1
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	20.4	20.6	19.6	19.0	23.6	22.6	20.3	13.3	19.2	22.3	19.9	19.7	20.0
Milner	ROR	5.0	5.0	0.0	0.0	9.7	9.6	6.2	0.0	0.0	0.0	0.0	0.0	3.0
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.5	6.5	8.7	8.2	9.2	9.2
Swan Falls	ROR	14.1	14.1	14.3	13.7	14.6	12.5	10.8	9.4	12.9	14.7	14.1	13.9	13.3
Twin Falls	ROR	8.5	8.1	3.8	0.0	12.4	13.1	10.1	0.0	0.0	4.8	4.5	5.5	5.9
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	12.0	12.2	11.6	11.2	14.7	13.7	11.9	6.8	11.0	13.3	11.4	11.3	11.8
Upper Salmon 3&4	ROR	11.4	11.7	11.1	10.8	13.8	12.9	11.4	7.0	10.6	12.6	10.9	10.9	11.3
HCC Total		**453.5**	**428.2**	**507.6**	**571.4**	**618.8**	**449.0**	**478.3**	**320.6**	**313.7**	**361.1**	**346.5**	**401.5**	**437.5**
ROR Total		**184.7**	**185.8**	**178.6**	**188.6**	**277.7**	**282.1**	**263.9**	**188.1**	**189.9**	**194.9**	**170.5**	**170.3**	**206.3**
Total		**638.2**	**614.0**	**686.2**	**760.0**	**896.5**	**731.1**	**742.2**	**508.7**	**503.5**	**556.0**	**517.0**	**571.8**	**643.8**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2030**	**2/2030**	**3/2030**	**4/2030**	**5/2030**	**6/2030**	**7/2030**	**8/2030**	**9/2030**	**10/2030**	**11/2030**	**12/2030**	**aMW**
Brownlee	HCC*	201.5	189.1	223.1	252.2	272.8	199.8	212.1	135.8	131.5	154.5	150.2	175.4	191.5
Oxbow	HCC	84.3	79.4	93.3	105.0	112.9	82.3	89.3	61.6	59.7	69.5	65.7	75.9	81.6
Hells Canyon	HCC	166.8	158.2	189.5	213.1	231.8	166.3	175.5	121.4	117.6	137.3	130.5	149.8	163.1
1000 Springs	ROR**	0.0	0.0	7.9	29.4	69.4	85.0	85.5	56.1	26.5	10.2	0.0	0.0	30.8
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	32.7	32.5	32.2	31.9	36.4	34.2	31.5	24.4	31.7	35.4	32.4	32.0	32.3
C .J. Strike	ROR	40.6	40.6	41.5	39.5	41.3	35.2	29.9	26.3	35.8	42.8	41.0	39.7	37.9
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	20.3	20.3	19.5	18.9	23.6	22.5	20.1	13.1	19.0	22.2	19.7	19.7	19.9
Milner	ROR	5.0	4.7	0.0	0.0	9.6	9.5	6.2	0.0	0.0	0.0	0.0	0.0	2.9
Shoshone Falls	ROR	12.0	12.0	7.3	3.9	12.0	12.0	12.0	6.5	6.5	8.7	8.2	9.2	9.2
Swan Falls	ROR	14.2	14.0	14.2	13.6	14.5	12.8	10.7	9.3	12.8	14.6	14.1	13.8	13.2
Twin Falls	ROR	8.5	8.0	3.8	0.0	12.3	13.0	10.1	0.0	0.0	4.8	4.5	5.5	5.9
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	11.8	12.0	11.5	11.1	14.7	13.6	11.8	6.7	10.8	13.2	11.3	11.3	11.7
Upper Salmon 3&4	ROR	11.3	11.5	11.0	10.7	13.8	12.8	11.3	6.9	10.5	12.5	10.9	10.9	11.2
HCC Total		**452.6**	**426.7**	**505.9**	**570.3**	**617.4**	**448.4**	**476.9**	**318.8**	**308.7**	**361.3**	**346.4**	**401.1**	**436.2**
ROR Total		**183.9**	**184.1**	**177.9**	**187.8**	**277.8**	**282.0**	**263.0**	**187.2**	**188.6**	**194.1**	**169.9**	**169.8**	**205.5**
Total		**636.5**	**610.8**	**683.8**	**758.1**	**895.2**	**730.4**	**739.9**	**506.0**	**497.3**	**555.4**	**516.3**	**570.9**	**641.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2031**	**2/2031**	**3/2031**	**4/2031**	**5/2031**	**6/2031**	**7/2031**	**8/2031**	**9/2031**	**10/2031**	**11/2031**	**12/2031**	**aMW**
Brownlee	HCC*	201.2	188.2	222.3	251.8	272.4	199.5	211.4	135.3	129.4	154.1	150.6	174.8	190.9
Oxbow	HCC	84.2	79.0	93.0	104.8	112.8	82.2	89.1	61.4	58.6	69.2	65.9	75.6	81.3
Hells Canyon	HCC	166.5	157.4	188.9	212.8	231.4	166.0	175.0	120.9	115.6	136.7	130.8	149.3	162.6
1000 Springs	ROR**	0.0	0.0	7.9	29.4	69.2	85.0	85.6	56.1	26.4	9.4	0.0	0.0	30.7
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	32.5	32.4	32.1	31.8	36.1	33.7	31.3	24.2	31.4	35.2	32.2	31.7	32.1
C .J. Strike	ROR	40.4	40.3	41.3	39.2	41.1	34.9	29.7	26.1	35.4	42.7	40.7	39.2	37.6
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	20.1	20.1	19.4	18.8	23.5	22.3	19.9	13.0	18.7	22.0	19.6	19.3	19.7
Milner	ROR	4.7	4.7	0.0	0.0	9.6	9.5	6.2	0.0	0.0	0.0	0.0	0.0	2.9
Shoshone Falls	ROR	12.0	11.9	7.3	3.9	12.0	12.0	12.0	6.5	6.5	8.4	8.2	8.9	9.1
Swan Falls	ROR	14.1	14.0	14.2	13.6	14.5	12.6	10.7	9.3	12.8	14.5	14.0	13.7	13.2
Twin Falls	ROR	8.4	7.9	3.8	0.0	12.3	13.0	10.1	0.0	0.0	4.6	4.5	5.3	5.8
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	11.7	11.9	11.4	11.0	14.6	13.5	11.7	6.5	10.7	13.0	11.2	11.1	11.5
Upper Salmon 3&4	ROR	11.2	11.4	11.0	10.6	13.7	12.7	11.2	6.8	10.3	12.3	10.8	10.7	11.1
HCC Total		**451.9**	**424.6**	**504.2**	**569.4**	**616.5**	**447.7**	**475.5**	**317.6**	**303.6**	**360.0**	**347.3**	**399.7**	**434.8**
ROR Total		**182.6**	**183.1**	**177.4**	**187.1**	**276.8**	**280.6**	**262.3**	**186.4**	**187.2**	**191.8**	**169.0**	**167.6**	**204.3**
Total		**634.5**	**607.7**	**681.6**	**756.5**	**893.3**	**728.3**	**737.8**	**504.0**	**490.8**	**551.8**	**516.3**	**567.3**	**639.2**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2032**	**2/2032**	**3/2032**	**4/2032**	**5/2032**	**6/2032**	**7/2032**	**8/2032**	**9/2032**	**10/2032**	**11/2032**	**12/2032**	**aMW**
Brownlee	HCC*	200.9	187.5	221.6	251.4	272.0	199.2	210.9	134.7	127.3	154.2	150.7	174.1	190.4
Oxbow	HCC	84.0	78.8	92.7	104.6	112.6	82.1	88.8	61.1	57.6	69.2	65.9	75.3	81.1
Hells Canyon	HCC	166.2	156.9	188.3	212.4	231.1	165.8	174.5	120.3	113.6	136.6	130.8	148.8	162.1
1000 Springs	ROR**	0.0	0.0	7.7	29.6	68.6	84.8	85.6	55.7	26.3	9.4	0.0	0.0	30.6
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	32.4	32.2	32.0	31.7	35.7	33.3	31.2	24.0	31.1	35.0	32.0	31.5	31.8
C .J. Strike	ROR	40.2	40.1	41.2	38.9	41.0	34.6	29.5	25.8	35.1	42.6	40.4	38.8	37.4
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	20.0	20.0	19.3	18.6	23.3	22.1	19.8	12.8	18.5	21.8	19.4	19.0	19.6
Milner	ROR	4.7	4.7	0.0	0.0	9.5	9.4	6.2	0.0	0.0	0.0	0.0	0.0	2.9
Shoshone Falls	ROR	12.0	11.9	7.3	3.9	12.0	12.0	12.0	6.5	6.5	8.4	8.1	8.9	9.1
Swan Falls	ROR	14.0	13.9	14.1	13.5	14.5	12.4	10.6	9.2	12.6	14.4	14.0	13.6	13.1
Twin Falls	ROR	8.4	7.9	3.8	0.0	12.2	12.9	10.1	0.0	0.0	4.6	4.4	5.3	5.8
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	11.6	11.8	11.4	10.9	14.5	13.3	11.5	6.4	10.5	12.9	11.0	10.8	11.4
Upper Salmon 3&4	ROR	11.2	11.3	10.9	10.5	13.6	12.6	11.1	6.7	10.2	12.2	10.6	10.5	11.0
HCC Total		**451.1**	**423.2**	**502.6**	**568.4**	**615.6**	**447.1**	**474.2**	**316.1**	**298.4**	**360.0**	**347.4**	**398.2**	**433.5**
ROR Total		**182.0**	**182.3**	**176.7**	**186.4**	**275.1**	**278.8**	**261.5**	**185.0**	**185.8**	**191.0**	**167.7**	**166.1**	**203.2**
Total		**633.1**	**605.5**	**679.3**	**754.8**	**890.7**	**725.9**	**735.7**	**501.1**	**484.2**	**551.0**	**515.1**	**564.3**	**636.7**

*HCC=Hells Canyon Complex,**ROR= Run of River

Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2033**	**2/2033**	**3/2033**	**4/2033**	**5/2033**	**6/2033**	**7/2033**	**8/2033**	**9/2033**	**10/2033**	**11/2033**	**12/2033**	**aMW**
Brownlee	HCC*	200.5	179.7	220.9	250.9	271.5	198.9	210.2	134.0	125.2	154.3	150.4	174.0	189.2
Oxbow	HCC	83.9	78.5	92.4	104.5	112.4	81.9	88.5	60.8	56.5	69.2	65.7	75.2	80.8
Hells Canyon	HCC	165.9	156.0	187.8	212.1	230.7	165.5	174.0	119.7	111.6	136.6	130.5	148.6	161.6
1000 Springs	ROR**	0.0	0.0	7.7	29.6	68.5	84.4	85.7	55.6	26.2	9.4	0.0	0.0	30.6
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	32.2	32.0	31.9	31.6	35.5	33.1	31.0	23.8	30.9	34.8	31.8	31.3	31.7
C .J. Strike	ROR	40.0	40.0	41.1	38.7	40.6	34.4	29.2	25.6	34.8	42.4	40.1	38.5	37.1
Cascade	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Clear Lake	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
Lower Malad	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Lower Salmon	ROR	19.9	19.8	19.2	18.5	23.2	21.7	19.6	12.7	18.3	21.7	19.2	18.9	19.4
Milner	ROR	4.7	4.7	0.0	0.0	8.7	8.6	6.2	0.0	0.0	0.0	0.0	0.0	2.7
Shoshone Falls	ROR	12.0	11.9	7.3	3.9	12.0	12.0	12.0	6.5	6.5	8.4	8.1	8.9	9.1
Swan Falls	ROR	14.0	13.8	14.1	13.4	14.4	12.0	10.5	9.1	12.5	14.3	13.9	13.6	13.0
Twin Falls	ROR	8.4	7.9	3.8	0.0	11.4	12.3	10.1	0.0	0.0	4.6	4.4	5.3	5.7
Upper Malad	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Upper Salmon 1&2	ROR	11.5	11.6	11.3	10.8	14.4	13.0	11.4	6.3	10.3	12.8	10.9	10.7	11.3
Upper Salmon 3&4	ROR	11.1	11.2	10.9	10.5	13.5	12.3	11.0	6.6	10.0	12.1	10.5	10.4	10.8
HCC Total		**450.3**	**414.2**	**501.1**	**567.5**	**614.6**	**446.3**	**472.7**	**314.5**	**293.3**	**360.1**	**346.6**	**397.8**	**431.6**
ROR Total		**181.3**	**181.4**	**176.3**	**185.8**	**272.4**	**275.2**	**260.6**	**184.1**	**184.5**	**190.2**	**166.7**	**165.3**	**202.0**
Total		**631.6**	**595.6**	**677.4**	**753.3**	**887.0**	**721.5**	**733.3**	**498.6**	**477.8**	**550.3**	**513.3**	**563.1**	**633.6**

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2034**	**2/2034**	**3/2034**	**4/2034**	**5/2034**	**6/2034**	**7/2034**	**8/2034**	**9/2034**	**10/2034**	**11/2034**	**12/2034**	**aMW**
Brownlee	HCC*	200.1	177.6	220.2	250.5	271.1	198.6	209.7	133.3	123.7	154.2	150.5	173.4	188.6
Oxbow	HCC	83.7	77.5	92.1	104.3	112.2	81.8	88.3	60.4	55.8	69.0	65.7	74.9	80.5
Hells Canyon	HCC	165.6	154.2	187.2	211.7	230.4	165.3	173.5	119.1	110.2	136.3	130.5	148.1	161.0
1000 Springs	ROR**	0.0	0.0	7.7	29.4	66.9	84.1	85.7	55.6	26.2	9.8	0.0	0.0	30.5
American Falls	ROR	6.2	6.3	6.2	5.9	6.0	6.0	5.9	6.1	6.2	6.2	6.2	6.2	6.1
Bliss	ROR	1.8	1.8	1.8	1.7	1.7	1.7	1.7	1.7	1.8	1.9	1.9	1.9	1.8
C .J. Strike	ROR	6.5	7.0	7.0	7.2	7.5	7.2	7.1	7.2	7.4	7.1	6.5	6.6	7.0
Cascade	ROR	11.5	12.0	12.7	12.8	13.5	12.3	12.2	12.6	13.3	13.0	11.9	11.8	12.5
Clear Lake	ROR	8.4	7.8	3.8	0.0	11.1	12.1	10.1	0.0	0.0	4.6	4.4	5.3	5.6
Lower Malad	ROR	12.0	11.8	7.3	3.9	12.0	12.0	12.0	6.5	6.5	8.4	8.1	8.9	9.1
Lower Salmon	ROR	11.0	10.9	10.8	10.4	13.4	12.1	10.9	6.5	9.9	12.0	10.4	10.3	10.7
Milner	ROR	11.4	11.4	11.2	10.8	14.2	12.8	11.3	6.2	10.2	12.6	10.7	10.6	11.1
Shoshone Falls	ROR	19.7	19.4	19.1	18.5	23.0	21.4	19.5	12.5	18.1	21.5	19.0	18.7	19.2
Swan Falls	ROR	32.1	31.9	31.8	31.5	35.1	33.0	30.9	23.6	30.7	34.6	31.6	31.2	31.5
Twin Falls	ROR	39.8	39.9	40.9	38.4	39.5	34.1	29.0	25.4	34.5	42.2	39.9	38.3	36.8
Upper Malad	ROR	13.9	13.8	14.1	13.3	13.9	11.9	10.5	9.0	12.4	14.3	13.7	13.4	12.9
Upper Salmon 1&2	ROR	1.4	1.4	1.3	1.3	1.5	4.2	7.0	10.3	6.4	1.4	1.3	1.3	3.2
Upper Salmon 3&4	ROR	4.6	4.1	0.0	0.0	8.3	8.2	6.2	0.0	0.0	0.0	0.0	0.0	2.6
HCC Total		**449.4**	**409.3**	**499.5**	**566.5**	**613.6**	**445.7**	**471.5**	**312.8**	**289.7**	**359.5**	**346.7**	**396.4**	**430.1**
ROR Total		**180.4**	**179.5**	**175.7**	**185.0**	**267.6**	**273.1**	**260.0**	**183.2**	**183.5**	**189.7**	**165.6**	**164.4**	**200.7**
Total		**629.8**	**588.8**	**675.2**	**751.5**	**881.2**	**718.8**	**731.5**	**496.0**	**473.2**	**549.2**	**512.3**	**560.8**	**630.7**

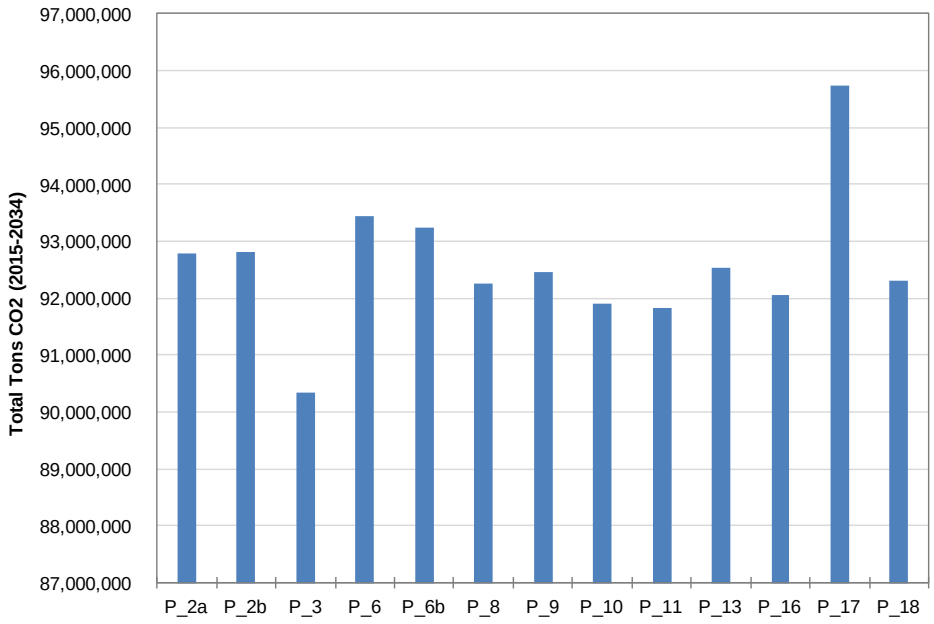
*HCC=Hells Canyon Complex,**ROR= Run of River

PORTFOLIO ANALYSIS, RESULTS, AND SUPPORTING DOCUMENTATION

Portfolio Emissions

IPC Systems

CO_2 Emission



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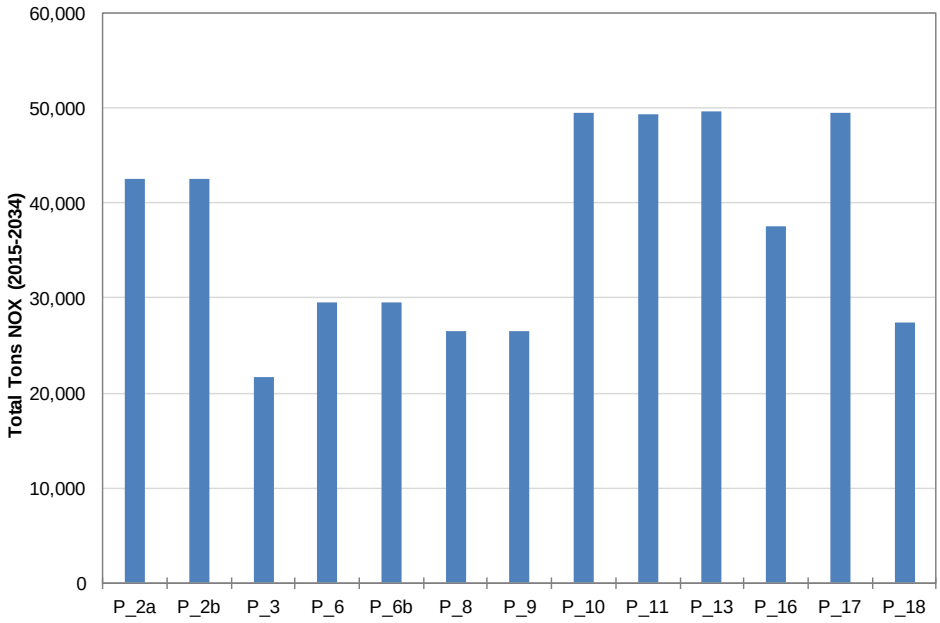
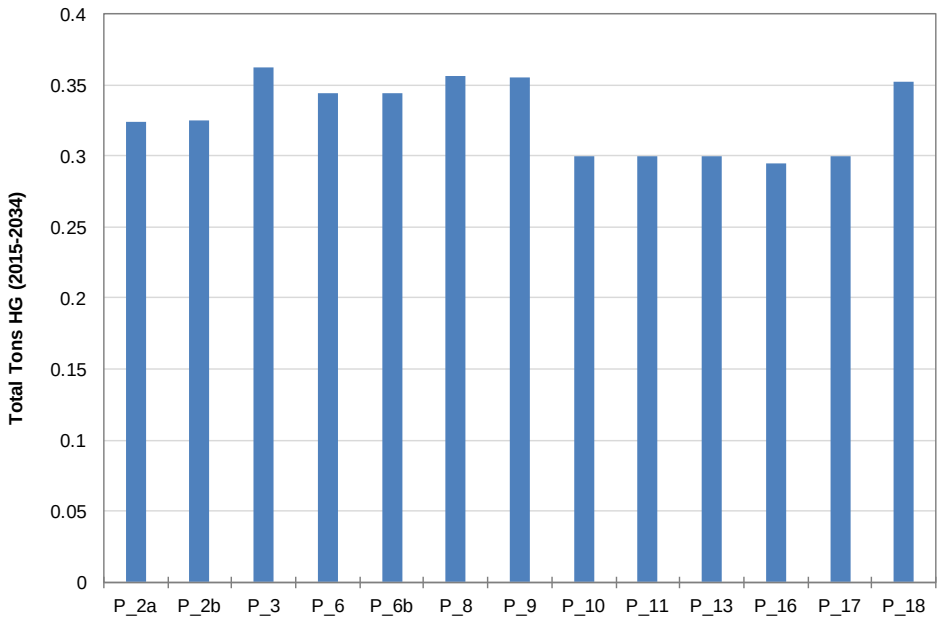


HG Emission



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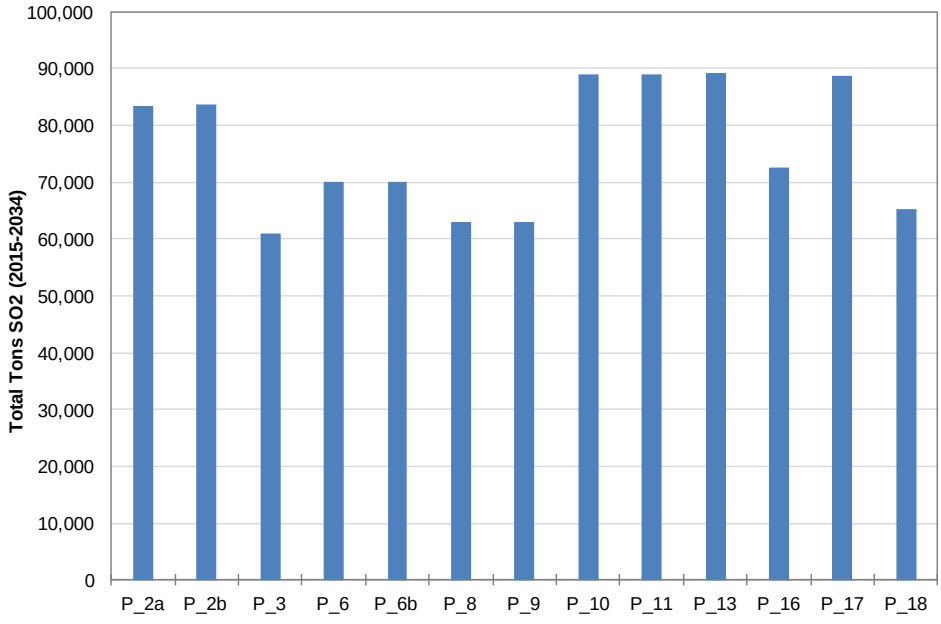

Loss of Load Expectation Analysis

Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 2a

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2015	0.11	0.00	0.00	0.00	0.00	0.00	0.02	0.09	0.00	0.00	0.00	0.00	0.00
2016	0.10	0.00	0.00	0.00	0.00	0.00	0.01	0.09	0.00	0.00	0.00	0.00	0.00
2017	0.02	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00
2018	0.05	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.00	0.00	0.00	0.00	0.00
2019	0.09	0.00	0.00	0.00	0.00	0.00	0.04	0.05	0.00	0.00	0.00	0.00	0.00
2020	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00
2021	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.00
2022	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.00
2023	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.52	0.00	0.00	0.00	0.00	0.00
2024	1.04	0.00	0.00	0.00	0.00	0.00	0.01	1.03	0.00	0.00	0.00	0.00	0.00
2025	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
2026	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00
2027	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00
2028	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00
2029	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.00	0.00	0.00	0.00	0.00
2030	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0.27	0.00	0.00	0.00	0.00	0.00
2031	0.49	0.00	0.00	0.00	0.00	0.00	0.00	0.49	0.00	0.00	0.00	0.00	0.00
2032	0.87	0.00	0.00	0.00	0.00	0.00	0.00	0.87	0.00	0.00	0.00	0.00	0.00
2033	1.54	0.00	0.00	0.00	0.00	0.00	0.00	1.54	0.00	0.00	0.00	0.00	0.00
2034	1.86	0.00	0.00	0.00	0.00	0.00	0.01	1.85	0.00	0.00	0.00	0.00	0.00

* With CBM@330 MW

Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 3

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2015	0.11	0.00	0.00	0.00	0.00	0.00	0.02	0.09	0.00	0.00	0.00	0.00	0.00
2016	0.10	0.00	0.00	0.00	0.00	0.00	0.01	0.09	0.00	0.00	0.00	0.00	0.00
2017	0.02	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00
2018	0.04	0.00	0.00	0.00	0.00	0.00	0.01	0.03	0.00	0.00	0.00	0.00	0.00
2019	0.09	0.00	0.00	0.00	0.00	0.00	0.04	0.05	0.00	0.00	0.00	0.00	0.00
2020	0.95	0.00	0.00	0.00	0.00	0.00	0.01	0.93	0.01	0.00	0.00	0.00	0.00
2021	1.46	0.00	0.00	0.00	0.00	0.00	0.01	1.43	0.02	0.00	0.00	0.00	0.00
2022	1.35	0.00	0.00	0.00	0.00	0.00	0.01	1.32	0.01	0.00	0.00	0.00	0.00
2023	1.51	0.00	0.00	0.00	0.00	0.00	0.02	1.47	0.02	0.00	0.00	0.00	0.00
2024	2.55	0.00	0.00	0.00	0.00	0.00	0.04	2.48	0.02	0.01	0.00	0.00	0.00
2025	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00
2026	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00
2027	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.00	0.00	0.00	0.00
2028	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.22	0.00	0.00	0.00	0.00	0.00
2029	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.00	0.00	0.00	0.00
2030	0.61	0.00	0.00	0.00	0.00	0.00	0.00	0.61	0.00	0.00	0.00	0.00	0.00
2031	0.96	0.00	0.00	0.00	0.00	0.00	0.00	0.95	0.00	0.00	0.00	0.00	0.00
2032	1.56	0.00	0.00	0.00	0.00	0.00	0.01	1.55	0.00	0.00	0.00	0.00	0.00
2033	2.16	0.00	0.00	0.00	0.00	0.00	0.01	2.14	0.01	0.00	0.00	0.00	0.00
2034	3.10	0.00	0.00	0.00	0.00	0.00	0.01	3.08	0.01	0.00	0.00	0.00	0.00

* With CBM@330 MW

Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 6b

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2015	0.11	0.00	0.00	0.00	0.00	0.00	0.02	0.09	0.00	0.00	0.00	0.00	0.00
2016	0.10	0.00	0.00	0.00	0.00	0.00	0.01	0.09	0.00	0.00	0.00	0.00	0.00
2017	0.02	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00
2018	0.05	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.00	0.00	0.00	0.00	0.00
2019	0.09	0.00	0.00	0.00	0.00	0.00	0.04	0.05	0.00	0.00	0.00	0.00	0.00
2020	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00
2021	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.00
2022	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.00
2023	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.52	0.00	0.00	0.00	0.00	0.00
2024	1.04	0.00	0.00	0.00	0.00	0.00	0.01	1.03	0.00	0.00	0.00	0.00	0.00
2025	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
2026	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.22	0.00	0.00	0.00	0.00	0.00
2027	0.44	0.00	0.00	0.00	0.00	0.00	0.00	0.43	0.00	0.00	0.00	0.00	0.00
2028	0.85	0.00	0.00	0.00	0.00	0.00	0.00	0.84	0.00	0.00	0.00	0.00	0.00
2029	1.44	0.00	0.00	0.00	0.00	0.00	0.01	1.42	0.00	0.00	0.00	0.00	0.00
2030	1.95	0.00	0.00	0.00	0.00	0.00	0.02	1.93	0.00	0.00	0.00	0.00	0.00
2031	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.28	0.00	0.00	0.00	0.00	0.00
2032	0.54	0.00	0.00	0.00	0.00	0.00	0.00	0.54	0.00	0.00	0.00	0.00	0.00
2033	0.87	0.00	0.00	0.00	0.00	0.00	0.00	0.86	0.00	0.00	0.00	0.00	0.00
2034	1.49	0.00	0.00	0.00	0.00	0.00	0.01	1.48	0.00	0.00	0.00	0.00	0.00

* With CBM@330 MW

Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 8

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2015	0.11	0.00	0.00	0.00	0.00	0.00	0.02	0.09	0.00	0.00	0.00	0.00	0.00
2016	0.10	0.00	0.00	0.00	0.00	0.00	0.01	0.09	0.00	0.00	0.00	0.00	0.00
2017	0.02	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00
2018	0.04	0.00	0.00	0.00	0.00	0.00	0.01	0.03	0.00	0.00	0.00	0.00	0.00
2019	0.09	0.00	0.00	0.00	0.00	0.00	0.04	0.05	0.00	0.00	0.00	0.00	0.00
2020	0.29	0.00	0.00	0.00	0.00	0.00	0.00	0.28	0.00	0.00	0.00	0.00	0.00
2021	0.83	0.00	0.00	0.00	0.00	0.00	0.01	0.81	0.01	0.00	0.00	0.00	0.00
2022	0.81	0.00	0.00	0.00	0.00	0.00	0.01	0.80	0.01	0.00	0.00	0.00	0.00
2023	1.21	0.00	0.00	0.00	0.00	0.00	0.01	1.19	0.01	0.00	0.00	0.00	0.00
2024	1.49	0.00	0.00	0.00	0.00	0.00	0.02	1.47	0.01	0.00	0.00	0.00	0.00
2025	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
2026	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.00
2027	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.21	0.00	0.00	0.00	0.00	0.00
2028	0.38	0.00	0.00	0.00	0.00	0.00	0.00	0.38	0.00	0.00	0.00	0.00	0.00
2029	0.71	0.00	0.00	0.00	0.00	0.00	0.00	0.71	0.00	0.00	0.00	0.00	0.00
2030	1.20	0.00	0.00	0.00	0.00	0.00	0.01	1.19	0.00	0.00	0.00	0.00	0.00
2031	1.36	0.00	0.00	0.00	0.00	0.00	0.01	1.35	0.00	0.00	0.00	0.00	0.00
2032	1.23	0.00	0.00	0.00	0.00	0.00	0.00	1.23	0.00	0.00	0.00	0.00	0.00
2033	1.28	0.00	0.00	0.00	0.00	0.00	0.00	1.27	0.00	0.00	0.00	0.00	0.00
2034	1.96	0.00	0.00	0.00	0.00	0.00	0.00	1.96	0.00	0.00	0.00	0.00	0.00

* With CBM@330 MW

Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 9

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2015	0.11	0.00	0.00	0.00	0.00	0.00	0.02	0.09	0.00	0.00	0.00	0.00	0.00
2016	0.10	0.00	0.00	0.00	0.00	0.00	0.01	0.09	0.00	0.00	0.00	0.00	0.00
2017	0.02	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00
2018	0.05	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.00	0.00	0.00	0.00	0.00
2019	0.09	0.00	0.00	0.00	0.00	0.00	0.04	0.05	0.00	0.00	0.00	0.00	0.00
2020	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.00
2021	0.94	0.00	0.00	0.00	0.00	0.00	0.01	0.92	0.01	0.00	0.00	0.00	0.00
2022	0.91	0.00	0.00	0.00	0.00	0.00	0.01	0.90	0.01	0.00	0.00	0.00	0.00
2023	1.45	0.00	0.00	0.00	0.00	0.00	0.01	1.42	0.01	0.00	0.00	0.00	0.00
2024	1.47	0.00	0.00	0.00	0.00	0.00	0.02	1.44	0.01	0.00	0.00	0.00	0.00
2025	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
2026	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00
2027	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.00	0.00	0.00	0.00
2028	0.42	0.00	0.00	0.00	0.00	0.00	0.00	0.42	0.00	0.00	0.00	0.00	0.00
2029	0.69	0.00	0.00	0.00	0.00	0.00	0.01	0.68	0.00	0.00	0.00	0.00	0.00
2030	1.33	0.00	0.00	0.00	0.00	0.00	0.01	1.31	0.00	0.00	0.00	0.00	0.00
2031	1.85	0.00	0.00	0.00	0.00	0.00	0.01	1.84	0.00	0.00	0.00	0.00	0.00
2032	0.72	0.00	0.00	0.00	0.00	0.00	0.00	0.71	0.00	0.00	0.00	0.00	0.00
2033	1.35	0.00	0.00	0.00	0.00	0.00	0.00	1.35	0.00	0.00	0.00	0.00	0.00
2034	2.08	0.00	0.00	0.00	0.00	0.00	0.01	2.07	0.00	0.00	0.00	0.00	0.00

* With CBM@330 MW

Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 10

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2015	0.11	0.00	0.00	0.00	0.00	0.00	0.02	0.09	0.00	0.00	0.00	0.00	0.00
2016	0.10	0.00	0.00	0.00	0.00	0.00	0.01	0.09	0.00	0.00	0.00	0.00	0.00
2017	0.02	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00
2018	0.05	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.00	0.00	0.00	0.00	0.00
2019	0.09	0.00	0.00	0.00	0.00	0.00	0.04	0.05	0.00	0.00	0.00	0.00	0.00
2020	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00
2021	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.00
2022	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.00
2023	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.52	0.00	0.00	0.00	0.00	0.00
2024	0.89	0.00	0.00	0.00	0.00	0.00	0.01	0.88	0.00	0.00	0.00	0.00	0.00
2025	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
2026	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
2027	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00
2028	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00
2029	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.00	0.00	0.00	0.00
2030	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.22	0.00	0.00	0.00	0.00	0.00
2031	0.42	0.00	0.00	0.00	0.00	0.00	0.00	0.42	0.00	0.00	0.00	0.00	0.00
2032	0.75	0.00	0.00	0.00	0.00	0.00	0.00	0.75	0.00	0.00	0.00	0.00	0.00
2033	0.47	0.00	0.00	0.00	0.00	0.00	0.00	0.47	0.00	0.00	0.00	0.00	0.00
2034	0.73	0.00	0.00	0.00	0.00	0.00	0.00	0.73	0.00	0.00	0.00	0.00	0.00

* With CBM@330 MW

Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 11

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2015	0.11	0.00	0.00	0.00	0.00	0.00	0.02	0.09	0.00	0.00	0.00	0.00	0.00
2016	0.10	0.00	0.00	0.00	0.00	0.00	0.01	0.09	0.00	0.00	0.00	0.00	0.00
2017	0.02	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00
2018	0.04	0.00	0.00	0.00	0.00	0.00	0.01	0.03	0.00	0.00	0.00	0.00	0.00
2019	0.09	0.00	0.00	0.00	0.00	0.00	0.04	0.05	0.00	0.00	0.00	0.00	0.00
2020	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00
2021	0.29	0.00	0.00	0.00	0.00	0.00	0.00	0.29	0.00	0.00	0.00	0.00	0.00
2022	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.28	0.00	0.00	0.00	0.00	0.00
2023	0.47	0.00	0.00	0.00	0.00	0.00	0.00	0.47	0.00	0.00	0.00	0.00	0.00
2024	1.55	0.00	0.00	0.00	0.00	0.00	0.02	1.52	0.01	0.00	0.00	0.00	0.00
2025	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00
2026	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00
2027	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00
2028	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.00
2029	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.21	0.00	0.00	0.00	0.00	0.00
2030	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.00	0.00	0.00	0.00
2031	0.62	0.00	0.00	0.00	0.00	0.00	0.00	0.61	0.00	0.00	0.00	0.00	0.00
2032	0.37	0.00	0.00	0.00	0.00	0.00	0.00	0.37	0.00	0.00	0.00	0.00	0.00
2033	1.15	0.00	0.00	0.00	0.00	0.00	0.00	1.14	0.00	0.00	0.00	0.00	0.00
2034	1.30	0.00	0.00	0.00	0.00	0.00	0.00	1.29	0.00	0.00	0.00	0.00	0.00

* With CBM@330 MW

Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 13

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2015	0.11	0.00	0.00	0.00	0.00	0.00	0.02	0.09	0.00	0.00	0.00	0.00	0.00
2016	0.10	0.00	0.00	0.00	0.00	0.00	0.01	0.09	0.00	0.00	0.00	0.00	0.00
2017	0.02	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00
2018	0.05	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.00	0.00	0.00	0.00	0.00
2019	0.09	0.00	0.00	0.00	0.00	0.00	0.04	0.05	0.00	0.00	0.00	0.00	0.00
2020	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00
2021	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.00
2022	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.00
2023	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.52	0.00	0.00	0.00	0.00	0.00
2024	0.89	0.00	0.00	0.00	0.00	0.00	0.01	0.88	0.00	0.00	0.00	0.00	0.00
2025	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
2026	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.18	0.00	0.00	0.00	0.00	0.00
2027	0.37	0.00	0.00	0.00	0.00	0.00	0.00	0.37	0.00	0.00	0.00	0.00	0.00
2028	0.70	0.00	0.00	0.00	0.00	0.00	0.00	0.70	0.00	0.00	0.00	0.00	0.00
2029	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.00
2030	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.00	0.00	0.00	0.00	0.00
2031	0.35	0.00	0.00	0.00	0.00	0.00	0.00	0.35	0.00	0.00	0.00	0.00	0.00
2032	0.62	0.00	0.00	0.00	0.00	0.00	0.00	0.62	0.00	0.00	0.00	0.00	0.00
2033	0.38	0.00	0.00	0.00	0.00	0.00	0.00	0.37	0.00	0.00	0.00	0.00	0.00
2034	0.60	0.00	0.00	0.00	0.00	0.00	0.00	0.60	0.00	0.00	0.00	0.00	0.00

* With CBM@330 MW

Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 16

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2015	0.11	0.00	0.00	0.00	0.00	0.00	0.02	0.09	0.00	0.00	0.00	0.00	0.00
2016	0.10	0.00	0.00	0.00	0.00	0.00	0.01	0.09	0.00	0.00	0.00	0.00	0.00
2017	0.02	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00
2018	0.05	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.00	0.00	0.00	0.00	0.00
2019	0.09	0.00	0.00	0.00	0.00	0.00	0.04	0.05	0.00	0.00	0.00	0.00	0.00
2020	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.00
2021	0.94	0.00	0.00	0.00	0.00	0.00	0.01	0.92	0.01	0.00	0.00	0.00	0.00
2022	0.91	0.00	0.00	0.00	0.00	0.00	0.01	0.90	0.01	0.00	0.00	0.00	0.00
2023	1.45	0.00	0.00	0.00	0.00	0.00	0.01	1.42	0.01	0.00	0.00	0.00	0.00
2024	1.47	0.00	0.00	0.00	0.00	0.00	0.02	1.44	0.01	0.00	0.00	0.00	0.00
2025	1.77	0.00	0.00	0.00	0.00	0.00	0.01	1.75	0.01	0.00	0.00	0.00	0.00
2026	0.90	0.00	0.00	0.00	0.00	0.00	0.01	0.89	0.00	0.00	0.00	0.00	0.00
2027	1.55	0.00	0.00	0.00	0.00	0.00	0.01	1.52	0.01	0.00	0.00	0.00	0.00
2028	2.79	0.00	0.00	0.00	0.00	0.00	0.02	2.76	0.01	0.00	0.00	0.00	0.00
2029	1.14	0.00	0.00	0.00	0.00	0.00	0.02	1.12	0.00	0.00	0.00	0.00	0.00
2030	1.99	0.00	0.00	0.00	0.00	0.00	0.03	1.95	0.01	0.00	0.00	0.00	0.00
2031	2.69	0.00	0.00	0.00	0.00	0.00	0.02	2.66	0.01	0.00	0.00	0.00	0.00
2032	1.12	0.00	0.00	0.00	0.00	0.00	0.00	1.12	0.00	0.00	0.00	0.00	0.00
2033	2.02	0.00	0.00	0.00	0.00	0.00	0.01	2.01	0.00	0.00	0.00	0.00	0.00
2034	2.95	0.00	0.00	0.00	0.00	0.00	0.02	2.92	0.01	0.00	0.00	0.00	0.00

* With CBM@330 MW

Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 17

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2015	0.11	0.00	0.00	0.00	0.00	0.00	0.02	0.09	0.00	0.00	0.00	0.00	0.00
2016	0.10	0.00	0.00	0.00	0.00	0.00	0.01	0.09	0.00	0.00	0.00	0.00	0.00
2017	0.02	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00
2018	0.05	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.00	0.00	0.00	0.00	0.00
2019	0.09	0.00	0.00	0.00	0.00	0.00	0.04	0.05	0.00	0.00	0.00	0.00	0.00
2020	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00
2021	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.00
2022	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.00
2023	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.52	0.00	0.00	0.00	0.00	0.00
2024	1.61	0.00	0.00	0.00	0.00	0.00	0.02	1.58	0.01	0.00	0.00	0.00	0.00
2025	1.81	0.00	0.00	0.00	0.00	0.00	0.01	1.79	0.01	0.00	0.00	0.00	0.00
2026	1.86	0.00	0.00	0.00	0.00	0.00	0.01	1.84	0.01	0.00	0.00	0.00	0.00
2027	2.09	0.00	0.00	0.00	0.00	0.00	0.02	2.06	0.01	0.00	0.00	0.00	0.00
2028	2.16	0.00	0.00	0.00	0.00	0.00	0.01	2.14	0.01	0.00	0.00	0.00	0.00
2029	2.26	0.00	0.00	0.00	0.00	0.00	0.02	2.23	0.01	0.00	0.00	0.00	0.00
2030	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.34	0.00	0.00	0.00	0.00	0.00
2031	0.59	0.00	0.00	0.00	0.00	0.00	0.00	0.59	0.00	0.00	0.00	0.00	0.00
2032	0.97	0.00	0.00	0.00	0.00	0.00	0.00	0.97	0.00	0.00	0.00	0.00	0.00
2033	1.36	0.00	0.00	0.00	0.00	0.00	0.01	1.35	0.00	0.00	0.00	0.00	0.00
2034	2.07	0.00	0.00	0.00	0.00	0.00	0.01	2.06	0.00	0.00	0.00	0.00	0.00

* With CBM@330 MW

Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 18

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2015	0.11	0.00	0.00	0.00	0.00	0.00	0.02	0.09	0.00	0.00	0.00	0.00	0.00
2016	0.10	0.00	0.00	0.00	0.00	0.00	0.01	0.09	0.00	0.00	0.00	0.00	0.00
2017	0.02	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00
2018	0.05	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.00	0.00	0.00	0.00	0.00
2019	0.09	0.00	0.00	0.00	0.00	0.00	0.04	0.05	0.00	0.00	0.00	0.00	0.00
2020	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00
2021	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.00
2022	0.91	0.00	0.00	0.00	0.00	0.00	0.01	0.90	0.01	0.00	0.00	0.00	0.00
2023	1.42	0.00	0.00	0.00	0.00	0.00	0.01	1.39	0.01	0.00	0.00	0.00	0.00
2024	1.59	0.00	0.00	0.00	0.00	0.00	0.02	1.56	0.01	0.00	0.00	0.00	0.00
2025	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
2026	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.00
2027	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.00	0.00	0.00	0.00
2028	0.44	0.00	0.00	0.00	0.00	0.00	0.00	0.43	0.00	0.00	0.00	0.00	0.00
2029	0.73	0.00	0.00	0.00	0.00	0.00	0.01	0.72	0.00	0.00	0.00	0.00	0.00
2030	1.34	0.00	0.00	0.00	0.00	0.00	0.01	1.33	0.00	0.00	0.00	0.00	0.00
2031	1.48	0.00	0.00	0.00	0.00	0.00	0.01	1.47	0.00	0.00	0.00	0.00	0.00
2032	1.78	0.00	0.00	0.00	0.00	0.00	0.01	1.77	0.00	0.00	0.00	0.00	0.00
2033	1.85	0.00	0.00	0.00	0.00	0.00	0.01	1.84	0.00	0.00	0.00	0.00	0.00
2034	2.37	0.00	0.00	0.00	0.00	0.00	0.01	2.35	0.00	0.00	0.00	0.00	0.00

* With CBM@330 MW

STATE OF OREGON IRP GUIDELINES

ORDER NO. 07-047

ENTERED 02/09/07

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1056

In the Matter of	)	
	)	
PUBLIC UTILITY COMMISSION OF OREGON	)	ERRATA ORDER
	)	
	)	
Investigation Into Integrated Resource Planning.	)	
	)	

DISPOSITION: APPENDIX TO ORDER NO. 07-002 CORRECTED

In Order No. 07-002, we adopted guidelines to govern the Integrated Resource Planning (IRP) process. In setting forth those guidelines in an appendix, we inadvertently omitted Guideline 1(d), which we discussed and adopted in the body of the order on pages 7 and 8. Accordingly, Appendix A to Order No. 07-002 is replaced with the attached appendix to this order, which includes all the adopted guidelines. The remainder of the order is unchanged.

IT IS SO ORDERED.

Made, entered, and effective FEB 09 2007.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

ORDER NO. 07-047

Adopted IRP Guidelines

Guideline 1: Substantive Requirements

a. *All resources must be evaluated on a consistent and comparable basis.*

- *All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.*
- *Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.*
- *Consistent assumptions and methods should be used for evaluation of all resources.*
- *The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.*

b. *Risk and uncertainty must be considered.*

- *At a minimum, utilities should address the following sources of risk and uncertainty:*

  1. *Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.*
  2. *Natural gas utilities: demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.*

- *Utilities should identify in their plans any additional sources of risk and uncertainty.*

c. *The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and*

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associated risks and uncertainties for the utility and its customers.[1]

- *The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.*

- *Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.*

- *To address risk, the plan should include, at a minimum:*

  1. *Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.*

  2. *Discussion of the proposed use and impact on costs and risks of physical and financial hedging.*

- *The utility should explain in its plan how its resource choices appropriately balance cost and risk.*

d. *The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.*

Guideline 2: Procedural Requirements.

a. *The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.*

[1] We sometimes refer to this portfolio as the "best cost/risk portfolio."

b. *While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.*

c. *The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.*

Guideline 3: Plan Filing, Review, and Updates.

a. *A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.*

b. *The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.*

c. *Commission staff and parties should complete their comments and recommendations within six months of IRP filing.*

d. *The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.*

e. *The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.*

f. *Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.*

g. *Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:*

- *Describes what actions the utility has taken to implement the plan;*
- *Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and*
- *Justifies any deviations from the acknowledged action plan.*

Guideline 4: Plan Components.

At a minimum, the plan must include the following elements:

a. *An explanation of how the utility met each of the substantive and procedural requirements;*

b. *Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;*

c. *For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;*

d. *For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;*

e. *Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;*

f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;

g. Identification of key assumptions about the future(e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;

h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;

i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;

j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;

k. Analysis of the uncertainties associated with each portfolio evaluated;

l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;

m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and

n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.

Guideline 5: Transmission.

Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote

locations, acquiring alternative fuel supplies, and improving reliability.

Guideline 6: Conservation.

a. *Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.*

b. *To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.*

c. *To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:*

- *Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and*
- *Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.*

Guideline 7: Demand Response.

Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).

Guideline 8: Environmental Costs.

Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.

Guideline 9: Direct Access Loads.

An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.

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Guideline 10: Multi-state Utilities.

Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.

Guideline 11: Reliability.

Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.

Guideline 12: Distributed Generation.

Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.

Guideline 13: Resource Acquisition.

a. *An electric utility should, in its IRP:*

- *Identify its proposed acquisition strategy for each resource in its action plan.*
- *Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.*
- *Identify any Benchmark Resources it plans to consider in competitive bidding.*

b. *Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.*

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Compliance with State of Oregon IRP Guidelines

Oregon Order 07-047 Action Items	2015 IRP
Guideline 1: Substantive Requirements a. All resources must be evaluated on a consistent and comparable basis. • All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand side options which focus on conservation and demand response. • Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling. • Consistent assumptions and methods should be used for evaluation of all resources. • The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs. b. Risk and uncertainty must be considered. • At a minimum, utilities should address the following sources of risk and uncertainty: 1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions. 2. Natural gas utilities: demand (peak, swing and baseload), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions. • Utilities should identify in their plans any additional sources of risk and uncertainty. c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. • The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource. • Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all longlived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases. • To address risk, the plan should include, at a minimum: 1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes. 2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging. • The utility should explain in its plan how its resource choices appropriately balance cost and risk. d. The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	a-1) Supply-side and purchased resources for meeting the utility's load are discussed in Chapter 3 (Idaho Power Today), section *Existing Supply-Side Resources*, pages 27–38. Demand-side options for meeting the utility's load are discussed in Chapter 4 (Demand-Side Resources). Chapter 6 (Transmission Planning) discusses transmission resources for meeting the utility's load. a-2) New resource options are described in Chapters 4 through 7. Chapter 4 (Demand-Side Resources) describes demand-side resource options for IRP resource portfolios. Chapter 5 (Supply-Side Generation and Storage Resources) describes generating resources and energy storage resources to be considered for IRP resource portfolios. Chapter 6 (Transmission Planning) describes transmission resources considered for IRP resource portfolios. Chapter 7 (Planning Period Forecasts) provides resource cost information. a-3) The consistent modeling method for evaluating new resource options is described in Chapter 7 (Planning Period Forecasts), sections *Resource Cost Analysis*, *Resource Cost Analysis II—Resource Stack*, and *Supply-Side Resource Costs*. The consistent modeling method for evaluating all resource portfolios is explained in Chapter 9 (Modeling Analysis and Results), pages 113–114. a-4) The WACC rate used to discount all future resource costs is stated in Chapter 9 (Modeling Analysis and Results), in Table 9.1 Financial Assumptions, on page 114. b-1) Electric utility risk and uncertainty factors (load, NG and water conditions) for resource portfolios are considered in Chapter 9 (Modeling Analysis and Results), section *Stochastic Risk Analysis*, pages 121–124. (For electricity prices, AURORA forecasts electric market prices; therefore AURORA variables are changed to create different electric market price scenarios). Sensitivity analysis for CAA Section 111(d) performed to address costs to comply with greenhouse gas regulations is discussed in Chapter 9 (Modeling Analysis and Results), section *CAA Section 111(d) Sensitivity Analysis*, beginning on page 114. Note: Plant forced outages for resource options and resource portfolios are not discussed in the IRP document or *2015 IRP Technical Appendix*. Plant forced outages are modeled in AURORA on a unit basis. b-1-other) Additional sources of risk and uncertainty are identified in Chapter 2 (Political, Regulatory, and Operational Issues) in the following sections: *FERC Relicensing*, page 14; *Idaho Water Issues*, page 15; *Northwest Power Pool Energy Imbalance Market*, page 19; and *Federal Energy Legislation CAA Section 111(d)*, page 21. Further discussion of risks is included in Chapter 9 (Modeling Analysis and Results), in section *Qualitative Risk Analysis*, beginning on page 125. Uncertainty factoring into the selection of the preferred portfolio is expressed in Chapter 1 (Summary) on pages 8-10. c-1) The IRP methodology and the planning horizon of 20 years are discussed in Chapter 1 (Summary), section *IRP Methodology,* page 3. c-2) Idaho Power uses the company's internal P-Worth model to calculate the PVRR for the capital component of the various portfolios. AURORA is used to model the variable (operating) component of the various portfolios. All costs are then discounted using the company's WACC. The summary of the NPV accounting for total portfolio costs is provided in Chapter 9 (Modeling Analysis and Results), pages 113-114.

Oregon Order 07-047 Action Items	2015 IRP
	c-1.) Measures of the variability of costs and the severity of bad outcomes are considered in Chapter 9 (Modeling Analysis and Results), section *Stochastic Risk Analysis,* pages 121–124. A discussion of extreme outcomes, including extreme bad outcomes, is provided in the *Stochastic Risk Analysis* section in the third paragraph of page 123. c-2.) The risks of physical and financial hedging are referenced to Idaho Power's *Energy Risk Management Policy* discussed in Chapter 1 (Summary), in the last paragraph of section *Introduction*, on page 2. Idaho Power explains how its preferred portfolio appropriately balances cost and risk in Chapter 9 (Modeling Analysis and Results), section *Preferred Portfolio*, page 130. The accounting for qualitative risks and uncertainty in the preferred portfolio selection is discussed in Chapter 1 (Summary), section *Portfolio Analysis Summary*, beginning on page 8. Further discussion of the preferred portfolio's appropriate balancing of cost and risk is included in Chapter 10 (Preferred Portfolio and Action Plan), section *Preferred Portfolio (2015-2034)*, page 141. d-1) The plan is consistent with long-run public interests and is discussed in Chapter 2 (Political, Regulatory, and Operational Issues). Additional discussion relevant to this requirement is in Chapter 1 (Summary), section *Public Advisory Process*, pages 2–3.
Guideline 2: Procedural Requirements. a. The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution. b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission. c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	As set forth in Guideline 2, part a., Idaho Power solicits public involvement in the planning process. The company convenes a public forum as part of the resource planning process. For the 2004, 2006, 2009, 2011, 2013, and 2015 plans, Idaho Power assembled an IRP Advisory Council composed of customer representatives, representatives from both the Idaho and Oregon public utility commission staffs, and representatives from special interest groups. A roster of the IRP Advisory Council members is provided in the technical appendices of the IRPs. The IRP Advisory Council meetings are open to the public. IRP Advisory Council meetings are attended by members of the public and Idaho Power has involved the public participants in the IRP Advisory Council's discussions. These meetings allow parties to make relevant inquiries of Idaho Power formulating the plan. As set forth in Guideline 2, part b., Idaho Power makes public extensive information relevant to its resource evaluation and action plan in its plan. This information is found throughout the 2015 IRP, the 2015 Load and Sales Forecast and in the 2015 Technical Appendix. As set forth in Guideline 2, part c., Idaho Power posted online a draft 2015 IRP for public review on Thursday, June 4, 2015. The company requested for comments to be provided no later than Friday, June 12, 2015.

Oregon Order 07-047 Action Items	2015 IRP
Guideline 3: Plan Filing, Review, and Updates. a. A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission. b. The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment. c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing. d. The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order. e. The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP. f. Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update. g. Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that: • Describes what actions the utility has taken to implement the plan; • Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and • Justifies any deviations from the acknowledged action plan.	a. The OPUC acknowledged Idaho Power's 2013 IRP on July 8, 2014 in Order 14-253. Idaho Power plans to file the 2015 IRP by June 30, 2015. b. Idaho Power will schedule a public meeting at the OPUC after the 2015 IRP has been filed. c. No action needed. d. No action needed unless the OPUC provides Idaho Power an opportunity to revise the plan. e. In Order No. 12-013, the OPUC provided direction on IRP flexible resource guidelines. In Order No. 14-253, the OPUC provided its resolution of fourteen components of the 2013 IRP. Idaho Power has addressed these action items in the 2015 IRP. f. In Order No. 14-253, the OPUC waived for Idaho Power the requirement to file an annual update to the 2013 IRP, the most recently acknowledged IRP. g. No action needed.

Oregon Order 07-047 Action Items	2015 IRP
Guideline 4: Plan Components. At a minimum, the plan must include the following elements: a. An explanation of how the utility met each of the substantive and procedural requirements; b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions; c. For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested; d. For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources; e. Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology; f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs; g. Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered; h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system; i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties; j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results; k. Analysis of the uncertainties associated with each portfolio evaluated; l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers; m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	a. Idaho Power anticipates delivering this table in an informal letter to the OPUC staff. b. Idaho Power revises the sales and load forecast each year and Idaho Power included the most recent sales and load forecast assumptions in Chapter 7 (Planning Period Forecasts), section *Load Forecast,* beginning on page 73.. High-growth scenarios at the 90th and 95th percentile levels for peak hour, and at the 70th and 90th percentile levels for energy are provided in Chapter 7, Figures 7.1 and 7.2 and Tables 7.1 and 7.2. High- and low-growth scenarios analyzed for the stochastic load risk analysis are discussed in Chapter 9 (Modeling Analysis and Results), section *Stochastic Risk Analysis,* pages 121-124. c. Peaking capacity and energy capability for each year of the plan for existing resources are discussed in Chapter 7 (Planning Period Forecasts), section *Generation Forecast for Existing Resources,* beginning on page 80. Idaho Power uses AURORA in the modeling of all existing transmission. Future transmission additions associated with the resource portfolios tested are discussed in Chapter 6 (Transmission Planning), section *Transmission Assumptions in the IRP Portfolios,* beginning on page 71. d. Not applicable. e. Supply-side resources considered are identified and described in Chapter 5 (Supply-Side Generation and Storage Resources). Resource costs are discussed and provided in Chapter 7 (Planning Period Forecasts), sections *Resource Cost Analysis*, *Resource Cost Analysis II—Resource Stack*, and *Supply-Side Resource Costs*. Demand-side resources and their levelized costs and technologies are covered in Chapter 4 (Demand-Side Resources). f. Resource reliability is covered in Chapter 9 (Modeling Analysis and Results), section *Loss of Load Expectation (LOLE),* beginning on page 139. g. Natural gas price forecasts are discussed in Chapter 7 (Planning Period Forecasts), section *Natural Gas Price Forecast*, page 84-85. Chapter 7 also includes key assumptions about future load in section *Load Forecast* and generation in section *Generation Forecast for Existing Resources*. Costs for environmental compliance with proposed CO_2 regulations are addressed in Chapter 9 (Modeling Analysis and Results), section *CAA Section 111(d) Sensitivity Analysis*, beginning on page 114. Compliance alternatives to SCR installation at Jim Bridger Units 1 and 2 are addressed by portfolios considering early retirement of Jim Bridger Units 1 and 2. Environmental compliance costs for SCR installation at Jim Bridger units 3 and 4 are addressed in the *Appendix C—Technical Appendix* in the section *Jim Bridger Units 3 and 4 Selective Catalytic Reduction Analysis*. h. Resource portfolios considered for the 2015 IRP are described in Chapter 8 (Portfolio Selection). Resource portfolios were developed using resources from the resource stack provided in Chapter 7 (Planning Period Forecasts), sections *Resource Cost Analysis*, *Resource Cost Analysis II—Resource Stack*, and *Supply-Side Resource Costs*. Resource portfolios were developed with consult from the IRP Advisory Council and public participants. i. The resource portfolios are evaluated against various risks in Chapter 9, Modeling Analysis and Results, section *Stochastic Risk Analysis,* pages 121–124. j. Portfolio cost and risk results, with interpretations, are provided in Chapter 9 (Modeling Analysis and Results). k. The uncertainties associated with each portfolio are evaluated in Chapter 9 (Modeling Analysis and Results), sections *Stochastic Risk Analysis* and *Qualitative Risk Analysis*. l. The selection reasoning for the preferred resource portfolio is identified in Chapter 9 (Modeling Analysis and Results), section *Preferred Portfolio*, page 130. m. No inconsistencies were identified. n. An action plan is provided in Chapter 1 (Summary), section *Action Plan*, page 10.

Oregon Order 07-047 Action Items	2015 IRP
Guideline 5: Transmission. Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	The transmission required for each resource being considered is described in the 2015 IRP *Technical Appendix*, section *Transmission Cost Assumptions*. Transmission assumptions for supply-side resources considered are included in Chapter 6 (Transmission Planning), section *Transmission Assumptions in the IRP Portfolios*, pages 71–72. AURORA accounts for the cost of wheeling when selling and purchasing power from the market. For natural gas-fired resources, the Idaho Citygate price reflects the cost of transport to a power plant. The Idaho Citygate price is described in Chapter 7 (Planning Period Forecasts), section Natural Gas Price Forecast, pages 84-85. Forecasts for Idaho Citygate price are provided in the 2015 IRP *Technical Appendix*, section *Fuel Price Forecasts*.
Guideline 6: Conservation. a. Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory. b. To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets. c. To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: • Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and • Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	a. The potential study conducted by Applied Energy Group (AEG) for the 2015 IRP is described in Chapter 4 (Demand-Side Resources), section *Committed Energy Efficiency Forecast*, beginning on page 43. b. The 2015 IRP action plan expresses Idaho Power's intent to continue pursuit of cost-effective energy efficiency. A forecast for energy efficiency effects in five-year blocks is provided in Chapter 4 (Demand-Side Resources), section *Committed Energy Efficiency Forecast*, Table 4.2. Detailed year-by-year forecast values are included in the 2015 IRP *Technical Appendix,* section *Monthly average energy load and resource balance*. c. Treatment of third party market transformation savings provided by the Northwest Energy Efficiency Alliance (NEEA) in the 2015 IRP is discussed in Chapter 4 (Demand-Side Resource), pages 40-41. Idaho Power has changed how market transformation savings provided by NEEA are treated in the IRP. NEEA savings are now included as savings to meet targets because of the overlap of NEEA initiatives and IPC's most recent potential study.
Guideline 7: Demand Response. Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	Demand response resources are detailed in Chapter 4 (Demand-Side Resources), section *Demand Response Performance,* page 42. Additional demand response above baseline levels is considered in select portfolios, including the preferred portfolio. The additional demand response is discussed in Chapter 4 (Demand-Side Resources), section *Additional Demand Response*, page 47.
Guideline 8: Environmental Costs. Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential CO^2 regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.	It is noted in Chapter 9 (Modeling Analysis and Results), section *Portfolio Emissions*, page 125, that with the exception of portfolios retiring Jim Bridger Units 1 and 2 without installation of NOx-controlling retrofits, all portfolios are designed to comply with environmental regulations. CAA Section 111(d) is modeled to reflect future carbon dioxide regulations. Portfolio costs provided for the considered CAA Section 111(d) sensitivities as provided in Chapter 9 (Modeling Analysis and Results), section *CAA Section 111(d) sensitivity analysis – results*, Table 9.4, page 119.
Guideline 9: Direct Access Loads. An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	At present, Idaho Power does not have any customers served by alternative electricity suppliers and Idaho Power has no direct access loads. Guideline 9 is not expected to apply to Idaho Power during the 2015 IRP 20-year planning period.
Guideline 10: Multi-state Utilities. Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.	Idaho Power intends to file the 2015 IRP in both the Idaho and Oregon jurisdictions.
Guideline 11: Reliability. Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demandside resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	Idaho Power discussed the capacity planning margin in Chapter 9 (Modeling Analysis and Results), section *Capacity Planning Margin*, beginning on page 131, and the loss of load probability in Chapter 9 (Modeling Analysis and Results), section *Loss of Load Expectation,* beginning on page 139.

Oregon Order 07-047 Action Items	2015 IRP
Guideline 12: Distributed Generation. Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	Idaho Power evaluated distributed solar PV as a resource option in portfolio 18. Portfolio 18 is described in Chapter 8 (Portfolio Selection), page 110. Distributed storage (ice-based thermal and V redox flow battery) resources were evaluated in multiple portfolios. Portfolios are described in Chapter 8 (Portfolio Selection), beginning on page 97. Distributed resources, generating and storage, were credited to account for avoided transmission line losses.
Guideline 13: Resource Acquisition. a. An electric utility should, in its IRP: • Identify its proposed acquisition strategy for each resource in its action plan. • Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party. • Identify any Benchmark Resources it plans to consider in competitive bidding. b. Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.	Idaho Power continues to evaluate resource ownership along with other supply options. Idaho Power conducts its resource acquisition and competitive bidding processes consistent with the guidelines established by Oregon in Order No. 14-149 issued on April 30, 2014. Idaho Power discusses asset ownership in Chapter 10 (Action Plan), section *Action Plan (2015–2018)*, page 143. Idaho Power's action plan includes ongoing permitting, planning studies, and regulatory filings associated with the Boardman to Hemingway transmission line. Construction of the Boardman to Hemingway transmission line will be managed to be consistent with resource acquisition and competitive bidding processes provided in guidelines established by Oregon in Order No. 14-149.

STATE OF OREGON IRP ELECTRIC VEHICLES (EV) GUIDELINES

ORDER NO. 12 013

ENTERED JAN 19 2012

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1461

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Investigation of matters related to Electric Vehicle Charging.	ORDER

DISPOSITION: GUIDELINES ADOPTED; UTILITIES ORDERED TO MAKE REVISED TARIFF FILINGS

I. PROCEDURAL HISTORY

At our December 8, 2009, Public Meeting, we opened this docket at our Staff's request to investigate matters related to the charging infrastructure for plug-in hybrid vehicles and electric vehicles (collectively referred to as EVs).[1] Specifically, we intended this docket to address general matters related to the emergence and development of the EV charging market and industry, including the role of electric utilities with regard to owning and operating EV service equipment (EVSE) and acting as EV service providers (EVSP). The Citizens' Utility Board of Oregon (CUB) noticed its intervention in the investigation, and the following parties were authorized over the course of the docket to intervene as parties: the Oregon Department of Energy (ODOE); ECOtality, Inc.; Smart Grid of Oregon (SGO); Grid Mobility LLC; Mitsubishi Motors R&D of America; the Oregon Department of Environmental Quality (DEQ); Nissan North America, Inc.; CleanFuture; the Northwest Energy Coalition (NWEC); Portland General Electric Company (PGE); PacifiCorp, dba Pacific Power (Pacific Power); and Idaho Power Company (Idaho Power).

On June 22, 2010, Staff and interested parties participated in a public workshop to discuss the scope of the investigation. Staff subsequently prepared a "straw proposal," published on July 22, 2010, that was intended to facilitate and focus further discussion in the docket. On August 6, 2010, a second public workshop was held. Staff and parties submitted opening comments on August 27, 2010.

[1] *See* Staff Report for December 8, 2009 Public Meeting, Item No. 4.

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2. *Resolution*

We agree with Staff and all of the other parties in this docket that there is no discernible reason, at least at this time, to treat EV charging load differently than any other load with regard to distribution system upgrades. Moreover, we acknowledge that EV charging load may not necessitate system upgrades at any time should the load be effectively managed. Consequently, we adopt Staff's recommendation that utilities' existing line extension policies continue to apply, without modification, to all loads, including plug-in EV load.

D. Integrated Resource Planning Flexible Resources Guidelines

The current Integrated Resource Planning (IRP) guidelines are silent regarding flexible capacity. In opening comments, Staff proposed an IRP guideline to fill this need.

1. *Parties' Positions*

Staff's proposed IRP guideline has three parts, as follows:

1. Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;

2. Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period; and

3. Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.

Staff asserts that the proposed IRP guideline is consistent with the language and content of the existing IRP guidelines, and addresses an issue that is relevant for resource and planning both now and in the future. Staff states, "[f]lexibility is an increasingly important consideration in the integration of higher percentages of variable renewable generation resources."[31] Staff further comments that "EVs, as the first 'smart appliance', represent an opportunity to capture the power of demand response flexibility as a compliment to other flexibility strategies coming from generation and storage technologies."[32] Although Staff realizes that EVs will not be ready to provide flexible

[31] Staff Response to Bench Request, p. 25.
[32] *Id.*

capacity any time soon due to measured market penetration and technical challenges, Staff argues that it appropriate to begin planning for the future and that a 20-year planning horizon is consistent with current IRP practice.

ECOtality, Inc., agrees, observing that as IRPs involve long-range planning, they should include developing technologies, or events may eclipse planning. ODOE recommends supports Staff's proposed IRP guideline. Neither NWEC nor CUB object to Staff's proposed IRP guideline, although CUB notes a possible practical limitation to EVs functioning as a flexible capacity resource should the manufacturers of EVs or EV batteries be reluctant to allow third parties access to EV battery storage capacity, thereby limiting flexible capacity availability from EVs.

All three utilities oppose adoption of Staff's proposed IRP guideline, arguing that the guideline is prematurely too prescriptive about planning for a resource that is still unknown and uncertain. Pacific Power complains about the administrative burden on a utility versus the analytical value of studies that would be undertaken pursuant to Staff's proposed guideline. Similarly, Idaho Power argues that given the significant uncertainties about whether and when EVs might provide flexible capacity, the Commission should direct utilities to consider, but not model such resources. PGE takes the position that adoption of Staff's proposed guideline is premature, and would impose long range speculative assumptions and create significant administrative burden.

All three utilities recommend further discussion and study in some other forum before adopting an IRP guideline related to flexible resource planning. Pacific Power urges the Commission to further study flexible capacity resources in a manner that accounts for each utility's planning and modeling framework, whether as part of an evolving investigation or through the public IRP processes. Pacific Power also notes that to the extent that these new guidelines are intended to inform the development of demand response programs more generally, the Commission should open an investigation to reevaluate all IRP guidelines related to demand response programs, rather than adopting certain new guidelines in an EV-specific proceeding. As already discussed, PGE suggests the Commission develop a pilot program to collect information to be used to late guide policy. PGE observes, however, that the company is increasing non-controllable variable generation in the form of wind and losing access to controllable flexible generation in the form of hydro. PGE acknowledges, therefore, that this situation makes the assessment of flexible generation an important component of PGE's IRP planning on a going forward basis. Consequently, PGE indicates that the first two parts of Staff's proposed guideline may have value. PGE argues, however, that it is unreasonable to link flexible capacity to EVs at this time, since EVs may be at least a decade away from commercial viability.

2. *Resolution*

At the outset, we conclude there is no need for further discussion on this issue. All three utilities submitted several rounds of comments regarding Staff's proposed guideline, including responses to our bench request. Although all three

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2. We direct each electric utility to fully address the new Integrated Resource Planning guideline adopted herein in the utility's next Integrated Resource Planning proceeding.

Made, entered, and effective JAN 19 2012.

John Savage
Commissioner

Susan K. Ackerman
Commissioner

Stephen M. Bloom
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

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Compliance with EV Guidelines

Oregon Order 12-013 Guideline	2015 IRP
Guideline 1: Forecast the Demand for Flexible Capacity. Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period; **Guideline 2: Forecast the Supply for Flexible Capacity.** Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period; **Guideline 3: Evaluate Flexible Resources on a Consistent and Comparable Basis** In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.	A discussion of the 2015 IRP's analysis for the flexibility guideline is provided in Chapter 9 (Modeling Analysis and Results), section Flexible Resource Needs Assessment, pages 135–139. Figure 9.4 on page 135 presents a projection for flexibility need across multiple timescales. Simulations of the system capability to provide flexibility are illustrated in Figures 9.5 through 9.9 on pages 136–138.

STATE OF OREGON ACTION ITEMS REGARDING IDAHO POWER'S 2013 IRP

ORDER NO. 12 253

ENTERED JUL 08 2014

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 58

In the Matter of IDAHO POWER COMPANY, 2013 Integrated Resource Plan	ORDER

DISPOSITION: PLAN ACKNOWLEDGED IN PART AND AS REVISED

I. INTRODUCTION

Idaho Power Company is a public utility operating in Oregon and is subject to the Commission's jurisdiction and requirements regarding integrated resource planning. Idaho Power's 2011 Integrated Resource Plan (IRP) was acknowledged with exceptions and guidance for its next IRP in Order No. 12-177. Idaho Power now seeks acknowledgment of its 2013 IRP.

We require each regulated energy utility to prepare and file an IRP within two years of acknowledgment of the utility's last plan. In the IRP, an energy utility must: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) aim to select a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create a plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.[1]

Once a utility completes a plan, we review for adherence to the procedural and substantive requirements outlined in Order No. 89-507. We generally acknowledge the plan—that is, find it reasonable based on the information available at that time—or return it to the utility with comments.[2] We may also decline to acknowledge specific action items if we question whether the utility's proposed resource decision presents the least cost and risk option for its customers.

We reaffirm our long-standing view that decisions made in IRP proceedings do not constitute ratemaking. Decisions whether to allow a utility to recover from its customers the costs associated with new resources may only be made in a rate proceeding. Acknowledgment of an IRP, however, is relevant to subsequent examination of whether a

[1] Order No. 07-002.
[2] *Id.* at 2.

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utility's resource investment is prudent and should be recovered from ratepayers. As we have previously stated:

> Consistency of resource investments with least-cost planning principles will be an additional factor that the Commission will consider in judging prudence. When a plan is acknowledged by the Commission, it will become a working document for use by the utility, the Commission, and any other interested party in a rate case or other proceeding before the Commission[.] Consistency with the plan may be evidence in support of favorable rate-making treatment of the action, although it is not a guarantee of favorable treatment.[3]

Just as acknowledgment does not guarantee favorable ratemaking, a decision to not acknowledge an action item does not constitute a preliminary determination of imprudence. The purpose of the IRP process is to provide the utility with the information and opinion of stakeholders and the Commission based on information presented by the utility. The question of whether a specific investment made by a utility in its planning process was prudent will be fairly examined in a subsequent rate case proceeding.

II. DISCUSSION

We conclude Idaho Power satisfies all the procedural guidelines and all but one of the substantive guidelines for IRP planning. Idaho Power did not comply with the IRP Guideline regarding flexible capacity adopted in Order No 12-013.

We acknowledge the short-term action items in Idaho Power's Action Plan, except for the investment in selective catalytic reduction emissions technology at Jim Bridger Units 3 and 4.[4] In addition, we acknowledge two additional action items recommended by Staff that relate to energy efficiency. We do not acknowledge the remaining action items, which are for the most part outside the two-to-four year action plan period.[5]

III. IDAHO POWER'S IRP

During the 20-year planning period, Idaho Power expects that the number of its customers will increase by about 8,400 each year, from approximately 500,000 in 2012 to 670,000 in 2032. Idaho Power's expected-case load forecast predicts that summer-peaking hour load requirements will grow at about 55 MW per year, and that the average-energy requirements will grow at 21 aMW per year. Idaho Power's load and resource balance analysis, which accounts for forecast load growth and generation from all of the company's existing resources and planned purchases, shows no energy deficits through the planning period. Idaho Power's analysis shows a capacity deficit starting in 2016 and monthly peak-hour deficit positions growing steadily in magnitude and the number of months affected. By July 2032, the capacity deficits are approximately 870 MW.

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[3] *Id.* at 24, *quoting* Order No. 89-507 at 7.
[4] *See* Appendix A.
[5] *See* Guideline 4(n).

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Idaho Power identifies as its major resource addition the Boardman to Hemingway transmission line (B2H) with market purchases. The company's preferred portfolio also includes demand response, continued operations at the Jim Bridger and North Valmy coal facilities after investment in emission-control technology, and the continued operation of Idaho Power's other existing supply-side resources.

Guideline 4(n) requires the utility to include an action plan with resource activities the utility intends to undertake over the next two to four years. Idaho Power includes the following activities in its Action Plan:

Year	Resource – Action
2013-2018	Boardman to Hemingway – Ongoing permitting, planning studies, and regulatory filings
2013	Gateway West – Ongoing permitting, planning studies, and regulatory filings
2013	North Valmy Unit 1 – Commit to the installation of dry sorbent injection emission-control technology
2013	Jim Bridger Units 3&4 – Commit to the installation of selective catalytic reduction emission-control technology
2016-2017	Demand response – Have demand response capacity available to satisfy deficiencies up to approximately 150 MW
2018	Boardman to Hemingway – Transmission line complete and in service
2019	Shoshone Falls – Upgrade complete and in service
2019	Jim Bridger Unit 2 – Commit to the installation of selective catalytic reduction emission-control technology
2020	Jim Bridger Unit 1 – Commit to the installation of selective catalytic reduction emission-control technology
2020	Boardman – Coal-fired operations at the Boardman plant are scheduled to end by year-end 2020
2024-2032	Demand response – Have demand response capacity available to satisfy deficiencies in 50 MW increments up to approximately 370 MW

IV. DISCUSSION

In this order, we first address Idaho Power's Action Plan, discussing the comments filed by participants[6] and specific IRP Guidelines as appropriate. We then address issues raised by the participants or that we identify related to Idaho Power's compliance with the IRP Guidelines and our order regarding Idaho Power's 2011 IRP that are not discussed in connection with our review of the Action Plan.

[6] Renewable Northwest (RNW), the Citizens' Utility Board of Oregon (CUB), the Oregon Department of Energy (ODOE), and Staff of the Public Utility Commission (Staff) filed opening and reply comments regarding Idaho Power's IRP, and Idaho Power filed two rounds of comments in response. In addition, a resident of Idaho, John Weber, forwarded comments to Staff, which Staff forwarded to the Administrative Hearings Division for inclusion in the record.

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A. Transmission

1. Boardman to Hemingway

Currently, the Boardman to Hemingway transmission project (B2H) is envisioned as a single-circuit 500 kV transmission line approximately 300 miles long between northeast Oregon and southwest Idaho. Idaho Power states that it has entered into a joint funding agreement with PacifiCorp and the Bonneville Power Administration to pursue permitting the project, under which Idaho Power is the permitting project manager.

Idaho Power proposes the following actions for the Boardman to Hemingway transmission project:

2013-2018	*Boardman to Hemingway – Ongoing permitting, planning studies, and regulatory filings*
2018	*Boardman to Hemingway – Transmission line complete and in service*

a. Participants' Comments

RNW supports investment in B2H because it would provide Idaho Power not only with transmission to a liquid market, enabling the company to access low-cost resources to meet capacity and energy needs, but to also generate revenue by selling energy to other regional utilities. RNW also contends B2H will provide environmental benefits by enabling Idaho Power to reach renewable energy resource zones, thereby facilitating renewable energy resources.

Staff recommends acknowledgement of ongoing permitting, planning studies, and regulatory filings for B2H. Staff notes that B2H is included in five of the nine portfolios modeled in the 2013 IRP. The preferred portfolio and the next lowest "total costs portfolios" include B2H. Staff finds that the IRP analysis regarding B2H supports acknowledgment of ongoing permitting, planning studies, and regulatory filings.

Staff recommends, however, that we decline to acknowledge B2H "Transmission line complete and in-service" in 2018. Staff reports that the estimated in-service date for B2H has moved from 2018 (the year noted in Idaho Power's IRP) to 2020 (the year reported in the company's reply comments). Staff concludes this action item is now well beyond the two-to-four year period prescribed in the IRP Guidelines.

With respect to Idaho Power's activities that occur between the our order in this docket and Idaho Power's 2015 IRP, Staff asks to be apprised of any (1) updated project plan incorporating changes related to Bureau of Land Management delays and Energy Facilities Siting Council developments; (2) final agreement regarding allocation of construction costs between project participants; and (3) significant regulatory decisions that impact the project schedule or costs. Staff also asks that the company to further explore whether B2H would significantly impact wind generation curtailment during

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periods of low demand as well as the impact of B2H on resource integration costs in general.

In its first round of comments, Idaho Power asserts that Staff's recommendation to acknowledge only the permitting activities of B2H and not the construction phase of the project is inconsistent with the our past acknowledgment of B2H and is unnecessary to ensure continued analysis of this project. In its final comments, Idaho Power states that it is only requesting acknowledgment of specific action items scheduled to occur within the next four years (which excludes the construction of B2H), but does ask that we acknowledge the 2013 IRP in its entirety, which includes B2H in its preferred portfolio.

b. Commission Resolution

We acknowledge ongoing permitting, planning studies, and regulatory filings for B2H. As Staff notes, the analysis in the IRP supports these planned near-term activities. We anticipate additional analysis regarding B2H in Idaho Power's 2015 IRP before acknowledging other actions related to B2H.

We decline to acknowledge completion of B2H because it is well beyond the two-to-four year period for action items specified by the IRP Guidelines. Further, we disagree with any suggestion that declining to acknowledge the construction of B2H is inconsistent with our previous acknowledgment of certain activities (*e.g.*, permitting) related to this resource or inconsistent with previous orders acknowledging IRPs based on a preferred portfolio that includes B2H. Our acknowledgment of an IRP is based on our conclusion that it complies with our guidelines and that the plan seems reasonable based on information known at the time.

2. Gateway West

Gateway West is a multi-segment, multi-year, joint transmission project of Idaho Power and PacifiCorp/Rocky Mountain Power to build and operate approximately 1000 miles of new transmission lines from Wyoming to the Hemingway Substation near Melba, Idaho. The project timeline indicates line segments in service between 2019 and 2023. Idaho Power has a one-third interest in some, but not all, of the segments to be located in Idaho and sole interest in one segment.

Idaho Power asks for acknowledgment of the following action item related to Gateway West:

2013 *Gateway West – Ongoing permitting, planning studies, and regulatory filings*

Idaho Power reports that the Gateway West and B2H projects are complementary and will provide an upgraded transmission path from the Pacific Northwest across Idaho and into eastern Wyoming with an additional transmission connection to a population center in Utah. Idaho Power states that Gateway West will benefit customers by (1) relieving transmission constraints on certain transmission paths allowing Idaho Power to move additional energy between the east and west sides of the system; (2) providing the option

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to locate future generation resources east of the Treasure Valley load center; and (3) providing future load service to the Magic Valley from the Cedar Hill Substation. Idaho Power does not request acknowledgment of Gateway West as a supply side resource. Instead, the company asserts that Gateway West is reasonable to address transmission system constraints and provide for future least cost resource development.

a. Participants' Comments

RNW supports investment in Gateway West because it will provide the same benefits that B2H will provide—that is, access to low-cost resources, access to regions where renewable resources could be sited, and reliability.

CUB recommends that we not acknowledge Gateway West as presented. CUB notes that Gateway West is a large project composed of a number of segments that can be analyzed individually. CUB asserts that Idaho Power should narrow its request and seek acknowledgment only of the segments of Gateway West that it can demonstrate are cost effective for Idaho Power's customers.

Staff concludes that, although there is insufficient information to support acknowledgment of the construction of Gateway West, we should acknowledge the permitting-related activities that must occur prior to construction. For purposes of Idaho Power's next IRP, however, Staff recommends that the company include an analysis of the historical and projected power flows for the portions of the Gateway West project in which Idaho Power has an interest in order to demonstrate the need and specific constraint-related benefits.

b. Commission Resolution

We acknowledge ongoing permitting, planning studies, and regulatory filings for Gateway West. However, as CUB notes, the project is composed of multiple segments that can and should be analyzed individually. Moreover, Idaho Power has an ownership interest in relatively few of the segments and must demonstrate the need and specific constraint-related benefits for each segment in which it holds an interest before we will consider acknowledgment of the project's construction.

B. Pollution Control Investments in Coal Resources

1. Idaho Power's Analysis

IRP Guideline 8, as modified by Order No. 08-339, contains four requirements related to environmental costs. Under this guideline, the utility must model a base case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. The utility must also develop several compliance scenarios ranging from the present CO_2 level to the upper reaches of credible proposals by governing entities. Then, the utility must estimate, under each of the compliance scenarios, the present value of revenue requirement (PVRR) cost and risk measures in its preferred portfolio and alternate portfolios. Guideline 8 directs the utility to identify the CO_2 emission cost adder level

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that triggers the selection of a portfolio that is substantially different from the preferred portfolio. In addition, Guideline 8 requires utilities develop a portfolio to achieve voluntary carbon emission reduction targets set forth in Oregon law.

a. Participants' Comments

RNW asserts that Idaho Power's analysis of its coal resources failed to meet IRP Guideline 8 because the company did not (1) model natural gas conversions of the Jim Bridger Units 3 and 4 boilers; (2) model a range of pollution control costs; and (3) account for recent direction from President Obama's Administration that may reduce the cost competitiveness of existing coal resources. RNW asserts that investing in coal units is generally not reasonable under scenarios with low natural gas costs or stringent CO_2 regulation or both.

CUB also criticizes Idaho Power's analysis, and contends the company failed to consider all possible scenarios. CUB proposes a four-part, Boardman-style analysis that (1) allows potential pollution controls under different scenarios; (2) compares the broader range of pollution control scenarios to alternative investments, such as repowering with natural gas, building a CCCT, or relying on front office transactions; (3) investigates whether there is a plausible scenario for a phase-out that is at a lower cost than either of the two options; and (4) analyzes whether committing to close a plant at the end of its depreciable life would reduce pollution control costs.

Staff voices a concern similar to CUB's regarding Idaho Power's failure to consider a range of early shutdown scenarios. Staff notes that Idaho Power compared the cost of early shutdown and no controls against other alternatives, but did not model a range of early shut-down scenarios, *e.g.*, smaller pollution control investment in exchange for shutdowns at different points in time, which Staff expected would be done. Like CUB, Staff recommends that future coal analysis consider alternative dates for pollution control equipment, shut down, or other alternatives such as gas conversion.

Staff concludes that Idaho Power's analysis is sufficient to comply with the IRP Guidelines, as well as our direction, provided in 2012, to evaluate whether there is flexibility in the emerging environmental regulations that would allow the company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives.

Idaho Power responds that its modeling complies with Guideline 8. Idaho Power notes that it modeled three levels of carbon adders to evaluate the potential impact of carbon emissions regulations in its coal study and in the IRP. In addition, Idaho Power explains it created an alternate portfolio in which the North Valmy units are converted to a gas-fired plant and Jim Bridger Units 3 and 4 are replaced with combined cycle combustion turbines (CCCTs). Idaho Power points out that President Obama's announcement regarding CO_2 regulation was issued the same month Idaho Power filed its IRP and that Idaho Power could not account for the announcement without delaying the filing of the 2013 IRP. And, Idaho Power asserts the June 2013 Presidential Memorandum concerned regulations for new power plants and none are included in the company's IRP.

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b. Commission Resolution

We conclude that Idaho Power's IRP complies with IRP Guideline 8, but as discussed below, is not sufficient to provide a basis to support acknowledgment of selective catalytic reduction emission-control technology (SCR) at Jim Bridger Units 3 and 4. Guideline 8 does not require Idaho Power to model every feasible alternative scenario, but requires the company to determine the PVRR costs and risk measures of a "set of reasonable alternative portfolios" assuming a range of different compliance scenarios. Although Idaho Power did not model a scenario in which both North Valmy units and Bridger Units 3 and 4 were converted to natural gas facilities, as RNW believes should have been done, Idaho Power did model a scenario in which North Valmy is converted to natural gas and Bridger Units 3 and 4 are replaced with CCCTs (portfolio 6). In addition, although Idaho Power did not build a compliance scenario that specifically accounts for the June 2013 Presidential Memorandum, Idaho Power did test its portfolios against a range of carbon compliance futures including a carbon adder in the planning case of $14.64 per ton beginning in 2018 and escalating three percent annually, and a carbon adder in the high case of $35 per ton beginning in 2018 and escalating nine percent annually.

The carbon adder was modeled at three levels: low ($0), planning, and high. Idaho Power did not model a distribution of values, as was done with gas prices, load, and hydro in the stochastic analysis. Instead, one-third of the simulations were drawn from each carbon adder level. The company's analysis showed the preferred portfolio 2 and the non-coal portfolio 6 would switch places at a carbon adder of $45 in 2018. We find the alternative portfolios selected by Idaho Power and the range of compliance futures sufficient to satisfy the requirements of Guideline 8.

We share CUB's and Staff's concern regarding the limited nature of Idaho Power's early retirement scenarios analysis. Even though Idaho Power may have technically complied with the action item from Order No. 12-177, we expected that Idaho Power would model a broader range of early shutdown scenarios. We expect Idaho Power to engage fully with Staff and stakeholders in a timely manner to design coal investment analyses for future IRPs to ensure more robust consideration of early shutdown as a compliance option.

Also, we direct Idaho Power to work with stakeholders to explore options for how it plans to model and perform analysis in the 2015 IRP in order to comply with the applicable emissions requirements of §111(d) of the Clean Air Act.

2. North Valmy Unit 1

North Valmy is a coal-fired plant consisting of two generating units located in Nevada. Idaho Power is a 50 percent owner of North Valmy. After adjusting for routine scheduled maintenance and estimated forced outages, the annual energy generating capability of Idaho Power's share of the plant is approximately 220 aMW. Idaho Power plans on the continued operation of North Valmy Unit 1 throughout the 20-year planning period of the 2013 IRP and both units of North Valmy are included in Idaho Power's preferred portfolio.

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Idaho Power proposes the following action for North Valmy Unit 1 to comply with federal Mercury Air Toxics Standards (MATS):

2013 *North Valmy Unit 1 – Commit to the installation of dry sorbent injection emission-control technology*

a. Participants' Comments

CUB is concerned because Idaho Power's preferred portfolio includes North Valmy with an end-of-life date that CUB fears is too far in the future. CUB notes that the end-of-life date for North Valmy is at or beyond the end of the 20-year planning period in Idaho Power's preferred portfolio but that the co-owner of North Valmy, Nevada Energy, has announced plans to close the plant in 2025.

Idaho Power responds that it modeled North Valmy consistently with its current expectation of the end-of-life date. Idaho Power asserts that Nevada Energy cannot close the plant early without Idaho Power's consent, which it has not given. Also, Idaho Power modeled two portfolios that included a shortened end-of-life date for North Valmy and replacement of lost energy with other resources. These portfolios were higher cost than the preferred portfolio.

Staff recommends acknowledgment of DSI installation. Staff finds that because the cost of the investment is so small, there is no tipping point in the modeled scenarios at which it is more cost-effective to shut down North Valmy rather than invest in DSI.

b. Commission Resolution

We acknowledge installation of DSI at North Valmy Unit 1. We find as Staff did that the relatively low cost of the investment leads to the conclusion that the DSI investment and continued operation of North Valmy is the least cost/least risk alternative given the information that is currently available.

We do not share CUB's concern regarding how Idaho Power included North Valmy in its preferred portfolio. First, shortening the life of North Valmy would not change the result of Idaho Power's analysis; installing DSI would still be the least cost/least risk alternative. Second, future events may lead to a shortened operating life for North Valmy, but whether they will is not certain. Idaho Power reasonably relied on the results of modeling based on the assumption North Valmy will operate as Idaho Power currently expects, rather than an assumption based on events that may, or may not, transpire.

3. Jim Bridger Units 3 and 4

Jim Bridger is a coal-fired plant consisting of four generating units located in Wyoming. Idaho Power owns one-third of the plant, or 771 MW. The Environmental Protection Agency (EPA) submitted a final rule on January 10, 2014, requiring the installation of selective catalytic reduction emission-control technology (SCR) at Bridger Units 3 and 4 by December 31, 2015 and December 31, 2016, respectively. Idaho Power's application to the Idaho Public Utilities Commission (IPUC) for a Certificate of Public Convenience

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and Necessity states that Idaho Power's cost before AFUDC is estimated to be approximately $118 million.

Idaho Power proposes the following action for Jim Bridger Units 3 and 4:

2013 *Jim Bridger Units 3 and 4 – Commit to the installation of selective catalytic reduction emission-control technology*

a. Participants' Comments

CUB and RNW recommend that we not acknowledge pollution control investments at Jim Bridger Units 3 and 4, contending additional analysis is needed. Specifically, CUB asserts that Idaho Power should analyze the effect that different early retirement dates would have on the need for pollution controls at Bridger Units 3 and 4 to inform whether the currently planned investment is cost-effective. CUB notes that a shorter life may reduce the controls needed (and therefore costs), making early retirement of coal plants more cost-effective than other options. RNW adds that Idaho Power did not adequately analyze conversion to natural gas or a sufficient range of future CO_2 compliance costs. Also, RNW believes that investing in coal units is generally not reasonable under scenarios with low natural gas costs or stringent CO_2 regulation or both.

Idaho Power disagrees with RNW's and CUB's conclusions regarding its analysis for Bridger Units 3 and 4, noting that it examined a range of options including early shutdown and conversion to natural gas, and that its analysis shows that installation of SCR at Bridger Units 3 and 4 is the least cost option for the majority of the alternate carbon and natural gas scenarios it modeled.

Staff recommends we acknowledge installation of SCR at Bridger Units 3 and 4. Staff concludes that Idaho Power's coal study demonstrates that the SCR investments are the lowest cost compared to the alternatives analyzed under planning case assumptions and in the majority of the carbon and gas sensitivities. In addition to reviewing the coal study, Staff constructed an independent spreadsheet analysis of the impact of a range of gas and carbon prices on the economics of the SCR investments, which confirmed the coal study results.

b. Commission Resolution

Based on the information we have at this time, we decline to acknowledge Idaho Power's action item related to Bridger Units 3 and 4. Our decision regarding these investments is inextricably tied to our decision regarding the same investments in the docket opened to address PacifiCorp's IRP, docket LC 57. In that docket, we did not acknowledge the investments for Bridger Units 3 and 4 for four interrelated reasons.

First, some of the alternatives modeled by PacifiCorp suggest that the installation of SCR at Bridger Units 3 and 4 is not the lowest cost resource option. Second, there were gaps in the analyses conducted by PacifiCorp. Third, some of the questions raised by Staff and other participants on the merit of retaining or retiring the units were not fully fleshed out, while others are more appropriately addressed in a rate proceeding. Finally, PacifiCorp,

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the managing utility, is proceeding with the investments, which calls into question the appropriateness of addressing the investments in a planning docket.

We recognize that Idaho Power conducted its own analysis of whether installing SCR at Bridger Units 3 and 4 is the least cost and least risk option. However, Idaho Power's analysis does not persuade us to reach a resolution in this docket that differs from that in docket LC 57, at least in part because of deficiencies in Idaho Power's analysis. More specifically, Idaho Power did not (1) analyze a full range of reasonable scenarios; (2) consider a wider range of resource replacement options as PacifiCorp; or (3) evaluate an adequate range of natural gas price sensitivities.

Idaho Power is proceeding with the investments. We will undertake a fair and thorough investigation of the prudence of the SCR investments when Idaho Power seeks rate recovery. Our decision to not acknowledge them in this docket does not prejudge the prudence of the investments for purposes of rate recovery.

C. Demand Response

Idaho Power proposes the following near-term action related to demand response:

2016-2017 *Have demand response capacity available to satisfy deficiencies up to approximately 150 MW*

a. Participants' Comments

Staff notes that both the Oregon and Idaho commissions recently issued orders approving stipulations regarding the redesign of Idaho Power's demand response programs for 2014 and beyond. Those stipulations provide that the annual value of demand response is equal to the levelized annual cost of the minimum size deferred resource, or 170 MW. Therefore, Staff recommends changing this action item to read: "Have demand response capacity available to satisfy deficiencies up to approximately ~~150 MW~~ 170 MW beginning in 2014, and increasing as needed through 2017."

Staff also recommends that the company update its assessment of demand response availability based on summer 2014 program participation and other relevant factors by the end of 2014. In addition, Staff recommends that the Energy Efficiency Advisory Group review any revisions to the resource assessment, along with other relevant factors.

RNW supports Idaho Power's continuation of its demand response program to meet the company's capacity needs.

b. Commission Resolution

We agree that revising the near-term demand response action item as recommended by Staff is appropriate in light of recently concluded dockets in Oregon and Idaho regarding demand response. We acknowledge the action item as revised by Staff. We also expect that Idaho Power will follow Staff's recommendation regarding updating its assessment of demand response availability in 2014.

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D. Long-term Action Items

Idaho Power's Action Plan includes the following long-term activities:

2019	*Shoshone Falls – Upgrade complete and in service*
2019	*Jim Bridger Unit 2 – Commit to the installation of selective catalytic reduction emission-control technology*
2020	*Jim Bridger Unit 1 – Commit to the installation of selective catalytic reduction emission-control technology*
2020	*Boardman – Coal-fired operations at the Boardman plant are scheduled to end by year-end*
2024-2032	*Demand Response – Have demand response capacity available to satisfy deficiencies in 50 MW increments up to approximately 370 MW*

a. Participants' Comments

Both Staff and CUB note, and Idaho Power acknowledges, that Idaho Power's Action Plan includes long-term action items in addition to the short-term action items typically presented in an IRP action plan. Staff and CUB recommend that we not acknowledge action items occurring beyond a two-to-four year period. In response, Idaho Power states that it does not seek acknowledgment of the long-term items.

b. Commission Resolution

Although Idaho Power states it does not seek acknowledgment of these long-term action items, they remain part of the company's IRP. For this reason, we believe it is necessary to address them. We do not acknowledge these action items because, as Staff and CUB note, the purpose of an action plan is to identify specific near-term actions that the company plans to take to meet its resource needs.[7] We generally do not acknowledge action items planned to occur more than four years in the future.[8]

D. Analysis of IRP

1. Wind Resources

a. Participants' Comments

Several participants raise concerns related to wind resources. RNW asserts that Idaho Power's IRP underestimates the capacity factor of modern wind turbines and includes an unsupported and unreasonably high wind integration rate.

Staff and RNW raise concerns about Idaho Power's wind integration study (WIS), and the company's use of the technical review committee (TRC) we recommended the

[7] *See* Order No. 12-177.
[8] *Id.*

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company form to improve such studies.[9] Staff notes that it anticipated more involvement of the TRC and recommends that Idaho Power engage with the TRC for future IRPs. RNW adds that Idaho Power's WIS based the size of the required balancing reserve on the difference between the day-ahead forecast and actual generation, which increased the assumed balancing reserves and costs. RNW notes that the TRC we required in Order No. 12-177 flagged this methodological assumption as a significant concern. Staff shares RNW's concern, and has reservations about using the study results in future filings.

In response to RNW's concern regarding overstated costs, Idaho Power notes the cost difference between the National Renewable Energy Laboratory (NREL) report and its costs comes from the conversion of 2009 dollars to 2013 dollars, the common base for the IRP's comparison of resource costs. In response to RNW's concern regarding the size of the balancing reserves, Idaho Power states that it chose to base the assumption on the day-ahead forecast because balancing reserves based on the hour-ahead forecast "would too often translate to a risky reliance on the wholesale energy market."

In response to RNW's concern regarding the average capacity factor, Idaho Power asserts that the NREL reports that Class 3 resources have an average capacity factor of 33 percent—a percentage Idaho Power adjusted downward to account for lower capacity factors of Class 2 resources. Idaho Power also asserts that its actual observations support the 26 percent average capacity factor used in the WIS and IRP.

In response to Staff's and RNW's concern regarding the role of the TRC, Idaho Power notes that we directed the company to form the committee in February 2012, nearly a year after the company had begun work on the WIS. Idaho Power announced the formation of the committee at an April 2012 workshop, but by this time the study was complete and the company was presenting preliminary study results.

b. Commission Resolution

We appreciate that Idaho Power responded quickly to our recommendation but are disappointed the TRC did not prove to be an effective mechanism for stakeholders to engage with Idaho Power regarding the analytical methodology of the WIS. Using the TRC to review and provide comments on the analytical methodology and results is not what we envisioned when making our 2012 recommendation. But, we recognize that our recommendation came late in Idaho Power's process, limiting the opportunity for TRC input.

We continue to recommend use of a TRC in connection with wind integration studies. The TRC could be an effective mechanism for stakeholders to engage with the company regarding the analytical methodology underlying the study and expect Idaho Power to engage with the TRC at the outset of any future study.

Regarding RNW's specific complaints regarding the WIS, we note that RNW does not urge us to disregard the WIS for the purpose of judging the reasonableness of Idaho Power's IRP, but cautions against using the WIS to determine avoided cost prices in a

[9] *Id.* at Appendix A at 3.

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future proceeding. Our acknowledgment of Idaho Power's IRP has no effect on the validity of the WIS during any proceeding to establish avoided cost prices for variable wind resources. We do note, however, that effective engagement between stakeholders and utilities regarding the study methodology and inputs would likely lessen disagreements in any proceeding in which the accuracy of the study is at issue.

2. *Capacity Contribution of Solar and Other Resources*

a. Participants' Comments

ODOE recommends certain changes to how Idaho Power examines capacity credits for solar, wind, and hydro resources, and how the company models orientation of flat-plate solar PV systems.

Idaho Power disagrees with ODOE's specific recommendation regarding the capacity contribution, but recognizes that solar resources are unique and that its analysis must address numerous considerations such as tracking systems, resource orientation, and materials. Idaho Power states it seeks to attribute the proper capacity credit to distributed solar PV and has initiated an IRP Advisory Council distributed solar PV workgroup to address the cost and capacity credit of distributed solar PV in the 2015 IRP. Idaho Power states that it anticipates the workgroup will address topics such as panel orientation and tracking systems. Idaho Power also states that it is analyzing integration of large-scale solar PV projects and working on this topic with members of its Solar Integration Study Technical Review Committee.

b. Commission Resolution

We appreciate Idaho Power's willingness to work on the issues identified by ODOE for its next IRP. We hope Idaho Power will work directly with ODOE. In any event, we expect to see results of Idaho Power's work in its 2015 IRP.

3. *Gas Price Forecasts*

a. Participants' Comments

Staff comments on three aspects of Idaho Power's natural gas price forecasts used in the IRP. Staff expresses concerns regarding the symmetric adjustments to the base case forecast, the escalation of the Energy Information Administration (EIA) reference case gas price forecast, and the high correlation between natural gas prices and wholesale electricity prices in the company's modeling. Staff identifies gas price forecasts as an issue to be analyzed during the development of the 2015 IRP. The company responds that its stochastic inputs are reasonable and that it will consider alternatives to deriving high and low gas price scenarios for future IRPs.

b. Commission Resolution

We anticipate that these analytical issues will be raised by Staff and addressed during the planning process for the 2015 IRP.

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4. *Flexibility Guideline*

In our investigation of matters related to electric vehicle charging, we adopted our Staff's recommendation to add an IRP guideline to require utilities to incorporate planning for flexible capacity in IRPs.[10] Utilities must forecast the balancing reserves needed at different time intervals to respond to variation in load and intermittent renewable generation over the 20-year planning period and to forecast the availability of balancing reserves at different time intervals. In planning to fill any gap between the demand and supply of flexible capacity, utilities must also evaluate all resource options on a consistent and comparable basis.

a. *Participants' Comments*

RNP asserts that Idaho Power's IRP does not comply with the IRP Guidelines because it does not forecast the demand for and supply of flexible capacity, or evaluate flexible resources on a consistent and comparable basis. RNW suggests that future IRPs should quantify the existing supply of flexible resources across multiple time scales, quantify the amount of reserves associated with each supply-side resource, and expand types of demand for flexible resources, *e.g.*, need to meet hourly ramps of load and other variable resources.

Idaho Power responds that its 2013 IRP did, in fact, include much of the flexibility analysis that RNW asserts is lacking. Idaho Power notes that a pumped storage hydro project was modeled as a resource alternative and as a tool to assist in the integration of wind resources. Idaho Power asserts that this modeling captured the flexibility and peaking capacity of the pumped storage hydro project and helped to integrate the variable wind generation into the system, and captured market arbitrage opportunities.

Staff recognizes that the company provided qualitative analysis that shows it is unlikely Idaho Power will need additional flexible capacity over the 20-year planning horizon, but agrees with RNW that the guideline asks for quantitative analysis of the size and timing of the flexible capacity resource balance. Staff recommends that Idaho Power substantially expand its analysis in the 2015 IRP. Staff is willing to work with Idaho Power and other stakeholders to help develop the quantitative analysis.

b. *Commission Resolution*

We find that Idaho Power's IRP does not comply with the Flexible Resources Guideline. Idaho Power did not submit the required analysis of demand and supply of balancing reserves disaggregated across multiple timescales. We expect the company to use the recommendations of both RNW and Staff to provide a compliant and more robust analysis regarding flexible resources in its 2015 IRP.

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[10] Order No. 12-013 at16-18.

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5. *Conservation Voltage Reduction*

Staff states that Idaho Power failed to include the required assessment of the available cost effective conservation voltage reduction (CVR) in its service area. Staff explains that we directed the assessment in our review of Idaho Power's 2012 IRP:

> The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The company will propose an action item in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts.[11]

We agree that Idaho Power's 2013 IRP failed to include this assessment, and direct the company to provide this assessment in its 2015 IRP.

In the interim, we direct our Staff to conduct the independent CVR and Volt/Var Ampere Reactive control programs we ordered in Idaho Power's 2013 Annual Smart Grid Report.[12] Staff should conduct the analysis within the next six months and report the results of the analysis to us at a public meeting.

6. *Energy Efficiency*

Although Idaho Power's IRP contains specific energy efficiency targets as part of its plan, the company does not include those amounts in the Action Plan. Staff proposes two action items to address energy efficiency:

2013-2017	*Energy Efficiency*	*The forecast reduction for 2013 to 2017 programs will be 69 aMW*
2013-2017	*Energy Efficiency*	*The incremental energy efficiency savings for 2013 to 2017 will reduce energy loads by 38 aMW*

We adopt Staff's proposed additions to the Action Plan.

7. *NEEA*

Idaho Power plans to curtail funding to the Northwest Energy Efficiency Alliance (NEEA) in the next five-year funding cycle. Idaho Power explains that it has asked NEEA to operate under an alternative funding model that would allow Idaho Power's funds to be directed toward the costs of activities that Idaho Power believes are most valuable to its customers. Idaho Power supports the concept of optional programs in NEEA's 2015-2019 Business Plan in which funders could choose to participate and fund certain programs or opt out of them altogether.

[11] Order No. 12-177 at 5.
[12] Order No. 13-481 at 1-2.

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a. Participants' Comments

CUB and Staff are concerned with Idaho Power's proposal to curtail funding to NEAA. Staff believes that NEAA is one of Idaho Power's most cost effective energy investments. Staff notes that NEEA is a compact between over 100 Northwest utilities and efficiency organizations that creates value for its supporters by broad market intervention and energy efficiency market development. NEEA's activities have resulted in the development of an energy efficiency products and practices pipeline to the region that benefits Idaho Power's and the region's ratepayers.

b. Commission Resolution:

We do not know Idaho Power's final decision about continued participation in NEEA. However, we are dismayed by the possibility that Idaho Power's approach could undermine support for regional market transformation. We agree with Staff's observations of the importance of NEEA. We believe that market transformation is an integral part of an effective energy efficiency strategy to lower cost and risk to ratepayers. Based on our analysis and our continued oversight of funding to NEEA from Oregon ratepayers, we believe that NEEA is capturing cost-effective energy efficiency over the long run and expanding opportunities for cost-effective energy efficiency in the future. For those programs Idaho Power opts out of, we expect Idaho Power will acquire commensurate savings from equivalent services at a cost equal to or less than what NEEA could provide.

D. Recommendations For Idaho Power's 2015 IRP

In Order No. 12-177, we reminded Idaho Power that IRP Guideline 4(n) requires utilities to include in an IRP action plan the resource activities the utility plans to undertake over the next two to four years to acquire the identified resources. We also recommended that Idaho Power's future IRPs include a "concise listing of action items for all resources and resource related activities, with each action item numbered."[13]

Idaho Power did include an action plan with resource activities it plans to take in the next two to four years, but the plan also includes longer-term actions. We clarify that, in future IRPs, Idaho Power should limit its Action Plan to activities it plans to undertake in the next two to four years. Idaho Power may compile other lists of activities planned for an extended period, as it has done in this IRP, but we recommend the company create and identify the action plan activities for which it requests specific acknowledgment. Again, we recommend that the company number each of these action items to facilitate our review.

E. IRP Update

Staff sought delays in these proceedings to facilitate our review of resource action items presented for acknowledgment in both PacifiCorp's IRP and Idaho Power's IRP.

[13] Order No. 12-177 at 8.

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As a result of this delay, Idaho Power's annual update to its 2013 IRP, which is due no later than 12 months after acknowledgment. However, Idaho Power must file its 2015 IRP with the Idaho Public Utilities Commission no later than June 2015. Idaho Power intends to file an IRP in Oregon at the same time it files in Idaho.

Given that Idaho Power will file its next IRP with the Idaho commission by June 2015, we waive the requirement that Idaho Power file an annual update to this IRP. This waiver addresses only a routine IRP update, and we expect Idaho Power to file an IRP update if it anticipates a significant deviation from its acknowledged 2013 IRP in the manner required by IRP Guideline 3(f).

V. ORDER

IT IS ORDERED that the 2013 Integrated Resource Plan filed by Idaho Power Company is acknowledged in part consistent with the terms of this order.

Made, entered, and effective JUL 08 2014.

Susan K. Ackerman
Chair

John Savage
Commissioner

Stephen M. Bloom
Commissioner

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Appendix A

Acknowledged Action Plan Items

Year	Resource - Action
2013- 2018	Boardman to Hemingway – Ongoing permitting, planning studies, and regulatory filings
2013	Gateway West – Ongoing permitting, planning studies, and regulatory filings
2013	North Valmy Unit 1 – Commit to the installation of dry sorbent injection emission-control technology
2016-2017	Have demand response capacity available to satisfy deficiencies up to approximately 170 MW beginning in 2014, and increasing as needed through 2017
2013-2017	Energy efficiency – The forecast reduction for 2013 to 2017 programs will be 69 aMW
2013-2017	The incremental energy efficiency savings for 2013-2017 will reduce energy loads by 38 aMW
2013-2015	CVR – Include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in service area and an action item related to this resource in the next IRP. Incorporate the planned energy savings and reduced peak demand into load-resource balance forecasts.

APPENDIX A
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Compliance with State of Oregon IRP Guidelines

A. Transmission

1. Boardman to Hemingway

Commission Resolution (Order No. 14-253):

We acknowledge ongoing permitting, planning studies, and regulatory filings for B2H. As Staff notes, the analysis in the IRP supports these planned near-term activities. We anticipate additional analysis regarding B2H in Idaho Power's 2015 IRP before acknowledging other actions related to B2H. We decline to acknowledge completion of B2H because it is well beyond the two-to-four year period for action items specified by the IRP Guidelines. Further, we disagree with any suggestion that declining to acknowledge the construction of B2H is inconsistent with our previous acknowledgment of certain activities (e.g., permitting) related to this resource or inconsistent with previous orders acknowledging IRPs based on a preferred portfolio that includes B2H. Our acknowledgment of an IRP is based on our conclusion that it complies with our guidelines and that the plan seems reasonable based on information known at the time.

Idaho Power Response (2015 IRP):

Discussion specific to B2H is found in Chapter 6 (Transmission Planning), section Boardman to Hemingway, pages 71-72. Portfolio design for the 2015 IRP provides a comparison of portfolios having B2H as a resource to portfolios not having B2H. A tabulation of resource portfolios with respect to B2H inclusion is provided in Chapter 8 (Portfolio Selection), section *Portfolio Design Summary*, page 111.

2. Gateway West

Commission Resolution (Order No. 14-253):

We acknowledge ongoing permitting, planning studies, and regulatory filings for Gateway West. However, as CUB notes, the project is composed of multiple segments that can and should be analyzed individually. Moreover, Idaho Power has an ownership interest in relatively few of the segments and must demonstrate the need and specific constraint-related benefits for each segment in which it holds an interest before we will consider acknowledgment of the project's construction.

Idaho Power Response (2015 IRP):

Discussion specific to Gateway West is found in Chapter 6 (Transmission Planning), pages 69–71. The results of a "need" analysis are provided in the section Gateway West Need Analysis, pages 70–71.

B. Pollution Control Investments in Coal Resources

1. Idaho Power's Analysis

Commission Resolution (Order No. 14-253):

We conclude that Idaho Power's IRP complies with IRP Guideline 8, but as discussed below, is not sufficient to provide a basis to support acknowledgment of selective catalytic reduction emission-control technology (SCR) at Jim Bridger units 3 and 4. Guideline 8 does not require Idaho Power to model every feasible alternative scenario, but requires the company to determine the PVRR costs and risk measures of a "set of reasonable alternative portfolios" assuming a range of different compliance scenarios. Although Idaho Power did not model a scenario in which both North Valmy units and Bridger units 3 and 4 were converted to natural gas facilities, as RNW believes should have been done, Idaho Power did model a scenario in which North Valmy is converted to natural gas and Bridger units 3 and 4

are replaced with CCCTs (portfolio 6). In addition, although Idaho Power did not build a compliance scenario that specifically accounts for the June 2013 Presidential Memorandum, Idaho Power did test its portfolios against a range of carbon compliance futures including a carbon adder in the planning case of $14.64 per ton beginning in 2018 and escalating three percent annually, and a carbon adder in the high case of $35 per ton beginning in 2018 and escalating nine percent annually.

The carbon adder was modeled at three levels: low ($0), planning, and high. Idaho Power did not model a distribution of values, as was done with gas prices, load, and hydro in the stochastic analysis. Instead, one-third of the simulations were drawn from each carbon adder level. The company's analysis showed the preferred portfolio 2 and the non-coal portfolio 6 would switch places at a carbon adder of $45 in 2018. We find the alternative portfolios selected by Idaho Power and the range of compliance futures sufficient to satisfy the requirements of Guideline 8.

We share CUB's and Staff's concern regarding the limited nature of Idaho Power's early retirement scenario analysis. Even though Idaho Power may have technically complied with the action item from Order No. 12-177, we expected that Idaho Power would model a broader range of early shutdown scenarios. We expect Idaho Power to engage fully with Staff and stakeholders in a timely manner to design coal investment analyses for future IRPs to ensure more robust consideration of early shutdown as a compliance option.

Also, we direct Idaho Power to work with stakeholders to explore options for how it plans to model and perform analysis in the 2015 IRP in order to comply with the applicable emissions requirements of Section 111(d) of the Clean Air Act.

Idaho Power Response (2015 IRP):

The 2015 IRP considers multiple early retirement scenarios as described in Chapter 8 (Portfolio Selection), pages 97–111. These early retirement scenarios were developed with input from the IRP Advisory Council and public participants of the IRP process, including input received at a portfolio design workshop held on January 28, 2015.

CAA Section 111(d) was discussed frequently during IRP Advisory Council meetings. A discussion led by IRP Advisory Council member John Chatburn (Idaho Office of Energy Resources) was held as part of the December 4, 2014 IRP Advisory Council meeting. Multiple sensitivities for CAA Section 111(d) were analyzed for the IRP. These sensitivities are described in Chapter 9 (Modeling Analysis and Results), section *CAA Section 111(d) Sensitivity Analysis*, pages 114–120.

2. North Valmy Unit 1

Commission Resolution (Order No. 14-253):

We acknowledge installation of DSI at North Valmy Unit 1. We find as Staff did that the relatively low cost of the investment leads to the conclusion that the DSI investment and continued operation of North Valmy is the least cost/least risk alternative given the information that is currently available.

We do not share CUB's concern regarding how Idaho Power included North Valmy in its preferred portfolio. First, shortening the life of North Valmy would not change the result of Idaho Power's analysis; installing DSI would still be the least cost/least risk alternative. Second, future events may lead to a shortened operating life for North Valmy, but whether they will is not certain. Idaho Power reasonably relied on the results of modeling based on the assumption North Valmy will operate as Idaho Power currently expects, rather than an assumption based on events that may, or may not, transpire.

Idaho Power Response (2015 IRP):

No action required.

3. Jim Bridger Units 3 and 4

Commission Resolution (Order No. 14-253):

Based on the information we have at this time, we decline to acknowledge Idaho Power's action item related to Bridger units 3 and 4. Our decision regarding these investments is inextricably tied to our decision regarding the same investments in the docket opened to address PacifiCorp's IRP, docket LC 57. In that docket, we did not acknowledge the investments for Bridger units 3 and 4 for four interrelated reasons.

First, some of the alternatives modeled by PacifiCorp suggest that the installation of SCR at Bridger units 3 and 4 is not the lowest cost resource option. Second, there were gaps in the analyses conducted by PacifiCorp. Third, some of the questions raised by Staff and other participants on the merit of retaining or retiring the units were not fully fleshed out, while others are more appropriately addressed in a rate proceeding. Finally, PacifiCorp, the managing utility, is proceeding with the investments, which calls into question the appropriateness of addressing the investments in a planning docket.

We recognize that Idaho Power conducted its own analysis of whether installing SCR at Bridger units 3 and 4 is the least cost and least risk option. However, Idaho Power's analysis does not persuade us to reach a resolution in this docket that differs from that in docket LC 57, at least in part because of deficiencies in Idaho Power's analysis. More specifically, Idaho Power did not (1) analyze a full range of reasonable scenarios; (2) consider a wider range of resource replacement options as PacifiCorp; or (3) evaluate an adequate range of natural gas price sensitivities.

Idaho Power is proceeding with the investments. We will undertake a fair and thorough investigation of the prudence of the SCR investments when Idaho Power seeks rate recovery. Our decision to not acknowledge them in this docket does not prejudge the prudence of the investments for purposes of rate recovery.

Idaho Power Response (2015 IRP):

A section titled Jim Bridger units 3 and 4 SCR Analysis is included in *Appendix C—Technical Appendix*.

C. Demand Response

Commission Resolution (Order No. 14-253):

We agree that revising the near-term demand response action item as recommended by Staff is appropriate in light of recently concluded dockets in Oregon and Idaho regarding demand response. We acknowledge the action item as revised by Staff. We also expect that Idaho Power will follow Staff's recommendation regarding updating its assessment of demand response availability in 2014.

Idaho Power Response (2015 IRP):

The performance of demand response programs in 2014 is provided in Chapter 4 (Demand-Side Resources), section *Demand Response Performance*, pages 42–43. Chapter 4 also notes that demand response is forecast to provide 390 MW of peak reduction during July throughout the planning period (section *Committed Demand Response*, page 46).

D. Long-Term Action Items

Commission Resolution (Order No. 14-253):

Although Idaho Power states it does not seek acknowledgment of these long-term action items, they remain part of the company's IRP. For this reason, we believe it is necessary to address them. We do not acknowledge these action items because, as Staff and CUB note, the purpose of an action plan is to identify specific near-term actions that the company plans to take to meet its resource needs. We generally do not acknowledge action items planned to occur more than four years in the future.

Idaho Power Response (2015 IRP):

The action plan provided in the 2015 IRP is focused on resource actions for the four-year period 2015-2018. The action plan is provided in Chapter 1 (Summary), section *Action Plan*, page 10–11. The action plan is also provided in Chapter 10 (Action Plan), section *Action Plan (2015–2018)*, pages 141–143.

E. Analysis of IRP

1. Wind Resources

Commission Resolution (Order No. 14-253):

We appreciate that Idaho Power responded quickly to our recommendation but are disappointed the TRC did not prove to be an effective mechanism for stakeholders to engage with Idaho Power regarding the analytical methodology of the WIS. Using the TRC to review and provide comments on the analytical methodology and results is not what we envisioned when making our 2012 recommendation. But, we recognize that our recommendation came late in Idaho Power's process, limiting the opportunity for TRC input.

We continue to recommend use of a TRC in connection with wind integration studies. The TRC could be an effective mechanism for stakeholders to engage with the company regarding the analytical methodology underlying the study and expect Idaho Power to engage with the TRC at the outset of any future study.

Regarding RNW's specific complaints regarding the WIS, we note that RNW does not urge us to disregard the WIS for the purpose of judging the reasonableness of Idaho Power's IRP, but cautions against using the WIS to determine avoided cost prices in a future proceeding. Our acknowledgment of Idaho Power's IRP has no effect on the validity of the WIS during any proceeding to establish avoided cost prices for variable wind resources. We do note, however, that effective engagement between stakeholders and utilities regarding the study methodology and inputs would likely lessen disagreements in any proceeding in which the accuracy of the study is at issue.

Idaho Power Response (2015 IRP):

No action required.While no IRP-related action is required, Idaho Power notes the use of a technical review committee from the outset of its first solar integration study, completed in June 2014. A technical review committee has also been in place since the January 2015 start of Idaho Power's second solar integration study.

2. Capacity Contribution of Solar and Other Resources

Commission Resolution (Order No. 14-253):

We appreciate Idaho Power's willingness to work on the issues identified by ODOE for its next IRP. We hope Idaho Power will work directly with ODOE. In any event, we expect to see results of Idaho Power's work in its 2015 IRP.

Idaho Power Response (2015 IRP):

Idaho Power convened public working group meetings to address solar-related issues, including capacity contribution, on August 6, 2014 and September 3, 2014. The results of the solar capacity contribution analysis conducted as part of the working group meetings are provided in Chapter 5 (Supply-Side Generation and Storage Resources), section *Solar Capacity Credit*, pages 50–51.

3. Gas Price Forecasts

Commission Resolution (Order No. 14-253):

We anticipate these analytical issues will be raised by Staff and addressed during the planning process for the 2015 IRP.

Idaho Power Response (2015 IRP):

The natural gas price forecast is provided in Chapter 7 (Planning Period Forecasts), section *Natural Gas Price Forecast*, pages 84–85. As noted in this section, Idaho Power uses EIA published nominal forecast prices. Also noted is the use of the EIA high resource case for the low case natural gas price forecast, and similarly use of the EIA low resource case for the high case natural gas price forecast. Finally, part of AURORA model calibration conducted for the IRP is verification that future power market (i.e., Mid-C) prices derived by the AURORA model maintain their historic relationship to natural gas market prices. The ratio of these prices, power market and natural gas market, is called the implied market heat rate. Idaho Power verified that future implied market heat rate values (ratio of AURORA-derived power market price to input natural gas market price) reasonably approximate historic values for this ratio. The implied market heat rate analysis was presented to the IRP Advisory Council and public participants at the February 5, 2015 IRP Advisory Council meeting.

4. Flexibility Guideline

Commission Resolution (Order No. 14-253):

We find that Idaho Power's IRP does not comply with the Flexible Resources Guideline. Idaho Power did not submit the required analysis of demand and supply of balancing reserves disaggregated across multiple timescales. We expect the company to use the recommendations of both RNW and Staff to provide a compliant and more robust analysis regarding flexible resources in its 2015 IRP.

Idaho Power Response (2015 IRP):

A discussion of the 2015 IRP's analysis for the flexibility guideline is provided in Chapter 9 (Modeling Analysis and Results), section *Flexible Resource Needs Assessment*, pages 135–139. Figure 9.4 on page 143 presents a projection for flexibility need across multiple timescales. Simulations of the system capability to provide flexibility are illustrated in Figures 9.5 through 9.9 on pages 136-138.

5. Conservation Voltage Reduction

Commission Resolution (Order No. 14-253):

Staff states that Idaho Power failed to include the required assessment of the available cost effective conservation voltage reduction (CVR) in its service area. Staff explains that we directed the assessment in our review of Idaho Power's 2012 IRP:

> The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The company will propose an action item in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts.

We agree that Idaho Power's 2013 IRP failed to include this assessment, and direct the company to provide this assessment in its 2015 IRP. In the interim, we direct our Staff to conduct the independent CVR and Volt/Var Ampere Reactive control programs we ordered in Idaho Power's 2013 Annual Smart Grid Report. Staff should conduct the analysis within the next six months and report the results of the analysis to us at a public meeting.

Idaho Power Response (2015 IRP):

CVR is discussed in Chapter 4 (Demand-Side Resources), section *Conservation Voltage Reduction*, page 48. The 2015 IRP's treatment of CVR was communicated to OPUC staff in a conference call on August 22, 2014.

6. Energy Efficiency

Commission Resolution (Order No. 14-253):

We adopt Staff's proposed additions to the Action Plan. [Staff proposed the addition of action plan items specifying IRP energy efficiency targets.]

Idaho Power Response (2015 IRP):

The action plan provided in the 2015 IRP includes an action item related to the pursuit of cost-effective energy efficiency, and expresses energy efficiency targets in a manner similar to that proposed by Staff. The action plan is provided in Chapter 1 (Summary), section *Action Plan*, pages 10–11. The action plan is also provided in Chapter 10 (Action Plan), section *Action Plan (2015–2018)*, pages 141–143.

7. NEEA

Commission Resolution (Order No. 14-253):

We do not know Idaho Power's final decision about continued participation in NEEA. However, we are dismayed by the possibility that Idaho Power's approach could undermine support for regional market transformation. We agree with Staff's observations of the importance of NEEA. We believe that market transformation is an integral part of an effective energy efficiency strategy to lower cost and risk to ratepayers. Based on our analysis and our continued oversight of funding to NEEA from Oregon ratepayers, we believe that NEEA is capturing cost-effective energy efficiency over the long run and expanding opportunities for cost-effective energy efficiency in the future. For those programs Idaho Power opts out of, we expect Idaho Power will acquire commensurate savings from equivalent services at a cost equal to or less than what NEEA could provide.

Idaho Power Response (2015 IRP):

Idaho Power continues its commitment to NEEA as a participant in NEEA's 2015-2019 funding cycle. On September 30, 2014 Idaho Power and NEEA executed a contract to participate in the 2015-2019 funding cycle. For complete details on Idaho Power's involvement in NEEA activities please see pages 9, 141-145 of the Company's Demand-Side Management 2014 Annual Report – Appendix B.