
Idaho's Electricity Sources

Current sources and future potential

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AUTHORS

Geoffrey Keith
Sarah Jackson
Joe Daniel, and
Kenji Takahashi



Synapse
Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

- 1. INTRODUCTION 1**

- 2. THE CURRENT ELECTRICITY FUEL MIX 2**
 - 2.1. Idaho Power 3
 - 2.2. Avista 5
 - 2.3. PacifiCorp 7
 - 2.4. The Electricity Imported into Idaho..... 10
 - 2.5. The Utilities’ Energy Efficiency Programs 11

- 3. RESOURCE POTENTIALS 14**
 - 3.1. Energy Efficiency 14
 - 3.2. Renewable Resources..... 18
 - Wind 19
 - Solar Energy 19
 - Geothermal 21
 - Biomass 22
 - Hydropower..... 23
 - 3.3. The Mid-Columbia Market..... 23

- 4. RESOURCE COSTS 25**
 - 4.1. Energy Efficiency Costs 25
 - 4.2. Renewable Resource Costs 28
 - Wind 28
 - Solar..... 30
 - Geothermal 32
 - Biomass 32
 - Hydropower..... 32

- 5. CONCLUSIONS..... 33**

- 6. REFERENCES 34**

1. INTRODUCTION

As part of this project, Synapse reviewed and compiled information on three aspects of Idaho's electric power industry:

- The fuel sources that make up the Idaho utilities' generation portfolios,
- The potential for energy efficiency and renewable resources to meet Idaho's electricity needs, and
- The Idaho utilities' efficiency and renewable cost assumptions.

For data on the Idaho utilities operations, we relied primarily on the companies' 2013 Integrated Resource Plans (IRPs). We have compared that data to information from a number of different sources as well as our own calculations. Section 2 presents data on the utility fuel mixes, focusing on the amount of electricity these companies generate outside of Idaho. In Section 3, we review the utilities' energy efficiency resource assessments and present data from other sources on the renewable resource potential in Idaho. In Section 4, we review the resource cost assumptions used in the utilities' IRPs and compare these assumptions to other cost estimates. We summarize our key findings in Section 5.



2. THE CURRENT ELECTRICITY FUEL MIX

Three utilities provide most of the electricity consumed in Idaho: Idaho Power, Avista, and Rocky Mountain Power. Figure 1 shows each company's percentage of 2012 sales. The remaining 14% of Idaho's electricity is provided by a number of smaller municipal utilities and cooperatives. This paper focuses on the three large utilities, their current sources of electricity, and their plans for the future.

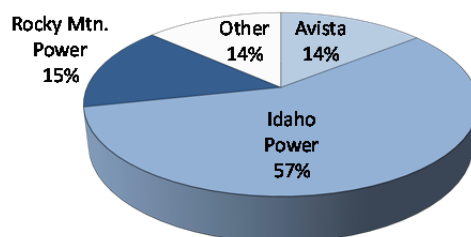
In addition to serving customers in Idaho, all three of these utilities serve customers outside of Idaho. Idaho Power sells 96% of its electricity in Idaho, while Avista sells 38% of its electricity in Idaho. Rocky Mountain Power sells only about 10% of its electricity in Idaho. Figure 2 shows the ratio of sales within and outside of Idaho for each utility. Rocky Mountain is owned by PacifiCorp, a company that also owns Pacific Power Company, which serves customers in Washington, Oregon, and California. Sales in Idaho are only 4% of PacifiCorp's total retail sales.

In this section, we present data on the generating assets these three utilities use to serve their customers in Idaho, focusing in particular on the amount of that electricity that is generated outside of Idaho. However, it is important first to review how utilities serve their loads. This will help us understand what can and cannot be deduced about the power plants that serve Idaho customers.

Most utilities do not maintain specific generation portfolios to serve customers in different locations or states. They assemble a single portfolio to meet all of their commitments. Today's regional transmission networks function like large bathtubs: each utility in the region puts water into the tub and each utility's customers take water out. There is no way to link specific customers to specific sources. Therefore, in most cases a utility's entire generation portfolio should be applied to all its customers, regardless of state lines. However, some utilities serve groups of customers that are separated by large distances and/or transmission constraints. In these cases, a certain group of generating assets may serve a distinct portion of a utility's load during most (but usually not all) hours of the year.

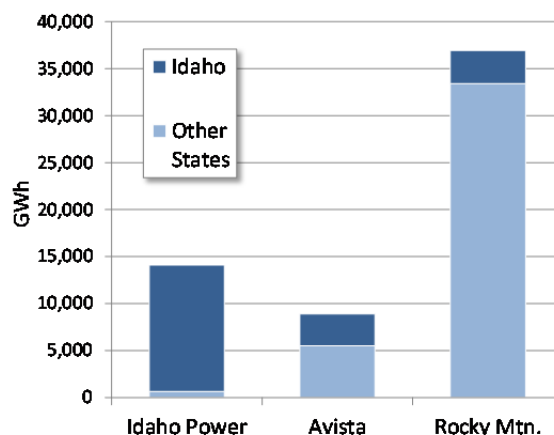
Utility generation portfolios are made up of owned power plants, contracts or power purchase agreements ("PPAs") of varying lengths, and short-term purchases from day-ahead or real-time energy markets.

Figure 1. Idaho Electricity Sales by Utility



Source: EIA Form 861, 2012.

Figure 2. Electricity Sales by State



Source: EIA Form 861, 2012.

2.1. Idaho Power

We apply the characteristics of Idaho Power’s full generating portfolio to its customers in both Idaho and Oregon. We do this because these two groups of customers are located very close to each other: the company’s Oregon service territory and its Idaho territory are contiguous.

In 2012, about 79% of Idaho Power’s electricity came from owned power plants, about 14% from PPAs, and 7% from spot market purchases (Idaho Power 2013a, Figure 3.3). As seen in Table 1, most of the company’s generating assets are in Idaho, but two of the out-of-state assets—Jim Bridger and North Valmy—are quite large and provide a significant portion of Idaho Power’s energy.

Table 1. Idaho Power’s Owned Generating Assets

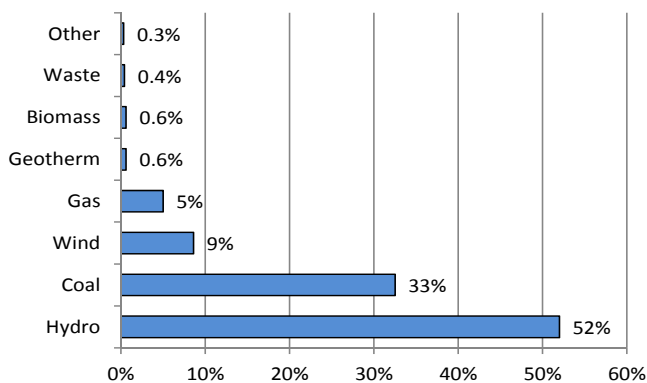
	Type	State	% Owned	MW Owned	Notes
Jim Bridger 1-4	Coal	MT	33%	771	
North Valmy 1-2	Coal	NV	50%	284	
Boardman	Coal	OR	10%	64	Scheduled for retirement in 2020
Langley Gulch	CCCT	ID	100%	318	Completed in 2012
Danskin	CT	ID	100%	271	
Bennett Mtn.	CT	ID	100%	173	
Salmon Diesels	IC	ID	100%	5	Emergency generators
American Falls	Hydro	ID	100%	92	
Bliss	Hydro	ID	100%	75	
Brownlee	Hydro	ID	100%	585	
CJ Strike	Hydro	ID	100%	83	
Cascade	Hydro	ID	100%	12	
Clear Lake	Hydro	ID	100%	2.5	
Hells Canyon	Hydro	ID	100%	392	
Lower Malad	Hydro	ID	100%	14	
Lower Salmon	Hydro	ID	100%	60	
Milner	Hydro	ID	100%	59	
Oxbow	Hydro	ID	100%	190	
Shoshone Falls	Hydro	ID	100%	13	Upgrades planned in 2016
Swan Falls	Hydro	ID	100%	27	
Thousand Springs	Hydro	ID	100%	9	
Twin Falls	Hydro	ID	100%	53	
Upper Malad	Hydro	ID	100%	8	
Upper Salmon A	Hydro	ID	100%	18	
Upper Salmon B	Hydro	ID	100%	17	
CHQ PV	PV	ID	100%	<0.1	

Source: Idaho Power (2013a) p. 23-32.

During the period of 2016 - 2019, Idaho Power plans to upgrade the Shoshone Falls hydroelectric project. The upgrade is expected to increase nameplate capacity from 12.5 to 61.5 MW (Idaho Power Company 2013a, page 36).

Idaho Power’s PPAs include Public Utility Regulatory Policy Act (PURPA) contracts with about 790 MW of nameplate capacity. A majority of this capacity is from wind plants (73%) and hydro plants (19%). The Company also has PPAs with the Elkhorn Valley Wind Project (101 MW) and the Raft River (13 MW) and Neal Hot Springs (22 MW) geothermal projects. (Raft River is the only geothermal project operating in Idaho.) The company’s 2013 IRP does not include acquisition of additional renewable energy. Short-term market purchases also make up a small amount of Idaho Power’s energy mix—about 7% in 2012.

Figure 3. Idaho Power’s 2012 Energy Fuel Mix



Compiled from data in Idaho Power (2013a).

Figure 3 shows Idaho Power’s 2012 energy mix, based on data in the 2013 IRP. This fuel mix includes generation from owned units, PPAs, and short-term market purchases. Short-term market purchases are given the net system fuel mix of the Northwest Power Pool (NWPP) as calculated by the Washington State Department of Commerce (WA DOC 2012).¹ The vast majority of the hydro energy is from Idaho Power’s own plants, although some of it is purchased. All of the coal energy is from the seven units in which the company has ownership shares. Though the company owns no wind projects, purchased wind energy makes up 9% of its mix.

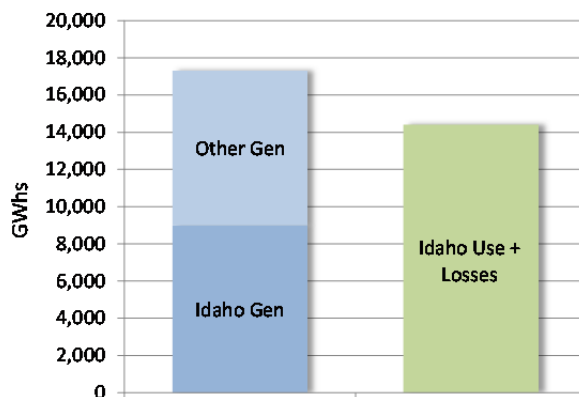
The primary driver of year-to-year changes in Idaho Power’s annual fuel mix is water availability for hydropower generation. In high water years, hydro plants provide larger portions of the company’s energy (e.g., 63% in 2011). In low water years, coal and gas provide larger portions. Also, gas-fired generation was up in 2012 relative to historical levels, and with lower gas prices and the completion of the Langley Gulch plant, gas is likely to continue to play a larger role in the company’s mix.²

¹ The Washington DOC calculates the electricity fuel mix of each utility active in Washington. To do this, DOC calculates a net system mix for NWPP each year. This is the fuel mix for the balance of power pool resources after utilities’ claims on specific resources are deducted. The net system mix is assigned to spot market purchases, which are not associated with a specified fuel source. For more, see: <http://www.commerce.wa.gov/Programs/Energy/Office/Utilities/Pages/FuelMix.aspx>.

² For information about Idaho Power’s historical fuel mix, see: <https://www.idahopower.com/AboutUs/EnergySources/FuelMix/fuelMix.cfm>.

We estimate that, in 2012, about 52% of Idaho Power’s electricity was generated in Idaho. The left bar in Figure 4 shows the portions of the company’s generation within and outside of Idaho. This estimate includes the output of owned units and PPAs for which the location of the resource is known. In addition to this energy, the company gets energy from over 100 PURPA contracts representing about 790 nameplate megawatts. Idaho Power’s IRP does not provide the location of these sources, so their output is not captured in Figure 4. Short-term energy purchases are also excluded from Figure 4, as the generation location is unknown. The company’s major in-state sources are owned hydro units, the gas-fired plant at Langley Gulch, and the Raft River geothermal plant. Major out-of-state resources include the seven coal-fired units shown in Table 1 and contracts with the Elkhorn wind and Neal geothermal projects.

Figure 4. Sources of Idaho Power Electricity, Sales to Idaho Customers



Source: Compiled from data in Idaho Power (2013a).

Figure 4 above also shows the amount of energy Idaho Power needs to serve customers in Idaho (calculated as sales plus losses). If we assume that all generation from the plants in Idaho goes to serve Idaho customers, then about 38% of the energy provided to customers in Idaho comes from out-of-state plants in a typical year.

2.2. Avista

As with Idaho Power, we apply the characteristics of Avista’s full generating portfolio to its customers in both Idaho and Washington. The power plants owned by Avista and the share of ownership are shown in Table 2. Note that only five of Avista’s owned plants are in Idaho.

Table 2. Avista’s Owned Generating Assets

	Type	State	% Owned	MW Owned	Notes
Colstrip 3	Coal	MT	15%	124	
Colstrip 4	Coal	MT	15%	124	
Rathdrum	Gas CTs	ID	100%	167	
Northeast	Gas CTs	WA	100%	61	
Boulder Park	Oil ICs	WA	100%	25	
Coyote Springs 2	Gas CCCT	OR	100%	287	
Kettle Falls	Gas CT	ID	100%	8	
Monroe St.	Hydro	ID	100%	15	Rebuilt in 1992
Post Falls	Hydro	WA	100%	15	
Nine Mile	Hydro	WA	100%	26	Upgrades underway

	Type	State	% Owned	MW Owned	Notes
Little Falls	Hydro	WA	100%	32	Upgrades underway
Long Lake	Hydro	WA	100%	82	
Upper Falls	Hydro	WA	100%	10	
Cabinet Gorge	Hydro	ID	100%	265	Upgrades 1994-07
Noxon Rapids	Hydro	MT	100%	518	Upgrades 2009-12
Kettle Falls	Biomass	ID	100%	46	

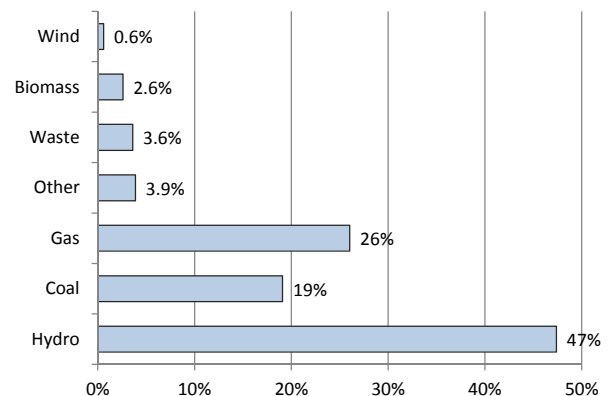
Source: Avista (2013), pages 2-22 to 2-27.

The upgrades planned at the Nine Mile project are expected to increase capacity by 6.4 MW. The upgrades underway at Little Falls will result in a small increase in annual energy production.

Avista’s PPAs include PURPA contracts with about 51 MW of nameplate capacity, composed of a mix of hydroelectric projects and plants burning wood and municipal waste. Avista also has PPAs with several mid-Columbia hydro projects, the Palouse Wind Project, and the Lancaster CCCT in Rathdrum Idaho. The company also has an energy exchange agreement with Bonneville, which provides Avista with a small amount of net energy each year (Avista 2013, p. 2-27 to 2-30).

Figure 5 shows Avista’s 2012 energy fuel mix. Again, the NWPP net system fuel mix has been applied to short-term purchases. Like Idaho Power, Avista relies most heavily on hydropower, and changes in annual precipitation are the main driver of changes in the annual fuel mix. In recent years, Avista’s hydroelectric percentage has been as high as 53% (in 2011). With ownership in only one coal-fired unit, Avista relies less heavily on coal than does Idaho Power.³

Figure 5. Avista’s 2012 Energy Fuel Mix



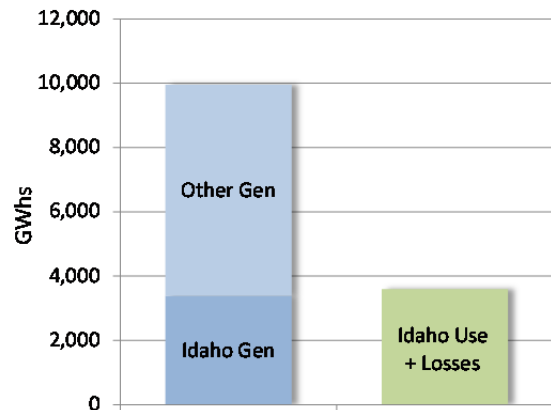
Source: Compiled from data in Avista (2013).

Like Idaho Power, Avista is not planning to invest in additional renewable energy other than REC purchases as necessary. The 2013 IRP states: “Avista expects to meet or exceed its renewable energy requirements through the 20-year plan with a combination of qualifying hydroelectric upgrades, the Palouse Wind project, the Kettle Falls Generating Station and selective renewable energy certificate (REC) purchases” (Avista 2013, p. vii).

³ For information about Avista’s recent annual fuel mixes, see: <http://www.commerce.wa.gov/Programs/Energy/Office/Utilities/Pages/FuelMix.aspx>.

We estimate that, in 2012, about 68% of Avista’s electricity was generated at plants outside of Idaho. The left bar in Figure 6 shows the generation breakdown for resources with known locations (owned plants, leases, and PPAs). The chart includes the vast majority of Avista’s 2012 energy—only a small amount of short-term purchases are not included. The company’s major non-Idaho sources are: owned hydro units in Washington, Colstrip in Montana, Coyote Springs 2 in Oregon, purchases from other hydro units in Washington, and the Palouse Wind project in Washington. Avista’s major Idaho sources are: the Lancaster CCCT, owned hydro units, and the Kettle Falls biomass plant.

Figure 6. Sources of Avista Electricity, Sales to Idaho Customers



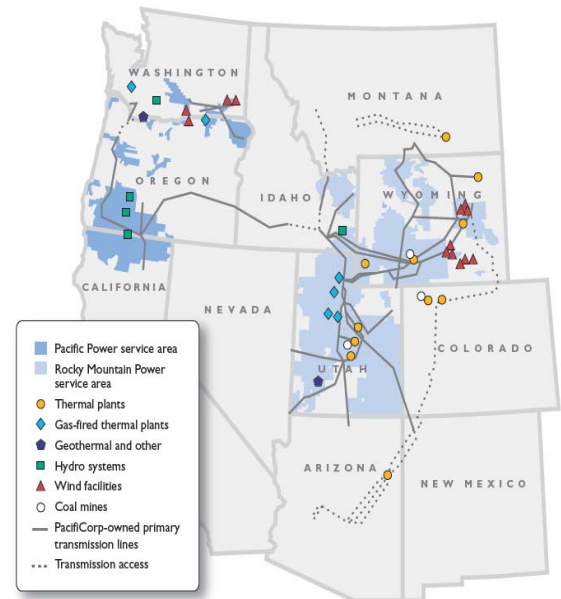
Source: Compiled from data in Avista Corporation (2013).

However, as seen in Figure 6, Avista’s generation in Idaho covers a large portion of its energy requirement in the state. If we assume that all generation from Avista’s plants in Idaho went to their Idaho customers, then only about 13% of the energy provided in Idaho came from out-of-state plants in 2012.

2.3. PacifiCorp

As seen in Figure 7, the PacifiCorp system is bifurcated into two distinct regions. PacifiCorp West includes the Pacific Power service area and a cluster of PacifiCorp power plants, primarily hydroelectric and gas-fired plants. PacifiCorp East includes the Rocky Mountain Power service area and a larger cluster of primarily coal-fired and gas-fired plants. The entire system serves customers in six states and includes power plants in nine states.

Figure 7. The PacifiCorp System



Source: PacifiCorp website.

The two regions are two separate controls areas, but PacifiCorp plans and dispatches the two areas on a single system basis and transfers energy between them. On an annual basis, PacifiCorp East generates more energy than Rocky Mountain Power customers use, and PacifiCorp West generates less than Pacific Power customers use. Therefore, energy transfers move east to west during most hours of the year.

Table 3 below shows PacifiCorp’s owned assets in PacifiCorp East (the Rocky Mountain region).

Table 3. PacifiCorp's Owned Generating Assets in the Rocky Mountain Region

	Type	State	% Owned	MW Owned	Notes
Carbon 1	Coal	UT	100%	67	
Carbon 2	Coal	UT	100%	105	
Cholla 4	Coal	AZ	100%	387	
Colstrip 3	Coal	MT	10%	74	
Colstrip 4	Coal	MT	10%	74	
Craig 1	Coal	CO	19%	84	
Craig 2	Coal	CO	19%	84	
Dave Johnston 1	Coal	WY	100%	106	
Dave Johnston 2	Coal	WY	100%	106	
Dave Johnston 3	Coal	WY	100%	220	
Dave Johnston 4	Coal	WY	100%	330	
Hayden 1	Coal	CO	24%	45	
Hayden 2	Coal	CO	13%	33	
Hunter 1	Coal	UT	94%	418	
Hunter 2	Coal	UT	60%	269	
Hunter 3	Coal	UT	100%	479	
Huntington 1	Coal	UT	100%	459	
Huntington 2	Coal	UT	100%	450	
Jim Bridger 1	Coal	WY	67%	354	
Jim Bridger 2	Coal	WY	67%	363	
Jim Bridger 3	Coal	WY	67%	349	
Jim Bridger 4	Coal	WY	67%	353	
Naughton 1	Coal	WY	100%	158	
Naughton 2	Coal	WY	100%	205	
Naughton 3	Coal	WY	100%	330	Conversion to gas expected 2015
Wyodac	Coal	WY	80%	268	
Chehalis	Gas	WA	100%	477	
Currant Creek	Gas	UT	100%	506	
Gadsby 1	Gas	UT	100%	57	
Gadsby 2	Gas	UT	100%	69	
Gadsby 3	Gas	UT	100%	105	
Gadsby 4	Gas	UT	100%	39	
Gadsby 5	Gas	UT	100%	39	
Gadsby 6	Gas	UT	100%	39	
Lake Side 1	Gas	UT	100%	545	
Lake Side 2	Gas	UT	100%	628	
West Valley	Gas	UT	0%	200	Leased
Big Fork	Hydro	MT	100%	4	

	Type	State	% Owned	MW Owned	Notes
Bear River	Hydro	ID/UT	100%	86	
Small East Hydro	Hydro	ID/UT/WY	100%	29	
Foote Creek I	Wind	WY	83%	33	
Glenrock I	Wind	WY	100%	99	
Glenrock III	Wind	WY	100%	39	
Rolling Hills	Wind	WY	100%	99	
Seven Mile Hill I	Wind	WY	100%	99	
Seven Mile Hill II	Wind	WY	100%	20	
High Plains	Wind	WY	100%	99	
McFadden Ridge I	Wind	WY	100%	29	
Dunlap I	Wind	WY	100%	111	
Blundell	Geotherm	UT	100%	34	

Source: PacifiCorp (2013).

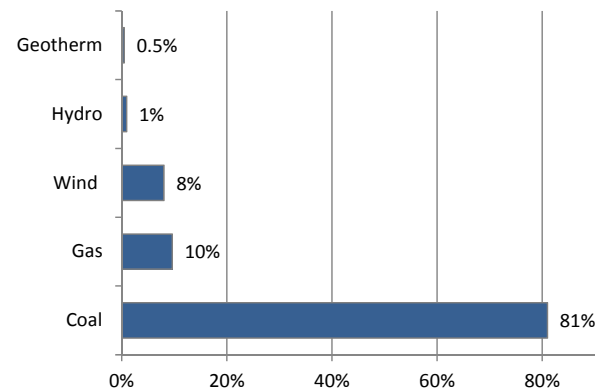
In addition to these units owned in the Rocky Mountain region, PacifiCorp lists PPAs with 23 wind projects, 15 of which are in the Rocky Mountain region. The contracts represent roughly 1,150 MW of nameplate wind capacity. The 2013 IRP refers to several other PPAs—specifically hydro and PURPA contracts—but does not provide information on the locations of the generators.

Figure 8. shows the estimated 2012 fuel mix of the plants in PacifiCorp East. This chart includes the estimated annual output of the owned units listed in Table 3 and the wind contracts that PacifiCorp identifies as being in its eastern balancing area. PacifiCorp provides no information about the typical annual output of its power plants; therefore, the data in Figure 8 are based on EPA data on fossil unit generation and assumed capacity factors for hydro, wind, and geothermal plants.

While Figure 8 is a reasonable estimate of the fuel mix provided to Rocky Mountain Power customers in Idaho, it is only an estimate. It does not include some purchased power, and energy from PacifiCorp plants in Washington or Oregon may serve Idaho customers during some hours of the year.

The vast majority of the electricity delivered to Rocky Mountain Power customers is generated outside of Idaho. The left bar in Figure 9 below shows the location of generation in PacifiCorp East. About 98% of it occurs outside of Idaho. This calculation includes the same generation included in the fuel mix estimate above; therefore, the same caveats apply here.

Figure 8. Estimated Energy Fuel Mix of PacifiCorp Eastern Area



Source: Compiled from data in PacifiCorp (2013).

Also shown in Figure 9, PacifiCorp’s generation in Idaho is considerably smaller than its energy requirement in the state. If we assume that all generation at PacifiCorp’s Idaho plants went to serve Idaho customers, then in 2012 about 75% of the energy provided to customers in Idaho came from out-of-state plants.

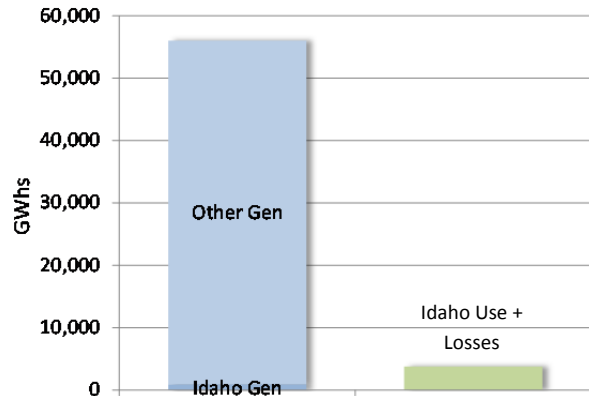
2.4. The Electricity Imported into Idaho

Based on the data presented above, about 8,500 GWh (39%) of the electricity the three utilities supplied in Idaho came from out-of-state plants in 2012. The vast majority of this was coal-fired energy. (As in the sections above, we are speaking in terms of the resources in the utilities’ supply portfolios, not attempting to follow electricity through the regional grid.)

Estimating the dollars flowing out of Idaho for this imported electricity is complicated. A utility maintains a portfolio of supply resources, and the annual cost of that portfolio changes over time. The “supply” or “generation” charge on customers’ bills is based on the current average cost of the utility’s supply portfolio. As an example of how a single power plant is paid for, consider a hypothetical new plant constructed by an Idaho utility:

- The utility finances the plant with equity and debt. The **equity** is raised from stockholders, who hope that ratepayers will repay them over time in the form of dividends and/or an appreciating stock value. These stockholders could be located anywhere globally, so most of these equity returns are likely to be leaving Idaho regardless of the plant location.
- For the **debt** portion, the utility borrows money from institutions that, again, could be located anywhere globally, so most or all of the interest paid is likely to be going out of Idaho, regardless of the plant location.
- In the case of a gas- or coal-fired plant, the **fuel** is likely to be purchased from companies outside of Idaho, regardless of where the plant is.
- A portion of **operating and maintenance costs (O&M)** would go to salaries and other labor on-site expenses, and this money would stay in Idaho if the plant were in Idaho. The balance of these costs would go to parts and equipment. Specialized (i.e., expensive) replacement parts would probably come from outside of Idaho, regardless of the plant location.
- The **insurance** company used would not depend on the location of the plant, but the destination of **property tax** payments would depend on plant location.

Figure 9. Sources of PacifiCorp Electricity, Sales to Idaho Customers



Source: Compiled from data in PacifiCorp (2013).

Therefore, the location of a new plant affects the destination of ratepayers’ payments only in some O&M areas and property taxes. This suggests that pushing to site new plants in Idaho would keep only a small portion of Idaho’s electricity dollars in state. Pushing the utilities to work with Idaho companies (banks, insurance companies, fuel and equipment suppliers), for example, could be more effective.

A “market value” of the electricity imported into Idaho can be estimated by applying an energy market price of \$44 per MWh to the 8,500 GWhs imported. This energy price is the average annual Mid-Columbia, day-ahead price between 2006 and 2012 (see Table 11 below), with all values converted to 2012 dollars. The estimated market value is just under \$370 million. However, this represents an energy value only, not capturing the capacity value of the plants from which the energy was imported.

2.5. The Utilities’ Energy Efficiency Programs

All three of the Idaho utilities have been operating demand-side management and energy efficiency programs since the beginning of the 1980s. The current levels of energy savings from their energy efficiency programs range from 0.4% to 1.2% of utility-specific annual sales, as shown in Table 4. Among the three utilities, Idaho Power has achieved the highest energy savings rate—more than twice the rate achieved by PacifiCorp or Avista. All three utilities have unequal shares of savings across customer sectors. For example, Idaho Power has only achieved 0.5% savings for its residential customers, while it achieved 1.5% savings for its commercial and industrial (C&I) customers. Similarly, Avista’s savings in the residential sector is very small at 0.2%, while the savings for its C&I customers is nearly 1%. In contrast, PacifiCorp is achieving larger energy savings in the residential sector relative to the C&I sector.

Table 4. 2012 Annual Energy Savings by the Three Investor Owned Utilities in Idaho

Sector	2012 Annual Savings (MWh)			2012 Annual Savings (% of Sales)		
	Idaho Power	Avista	PacifiCorp	Idaho Power	Avista	PacifiCorp
Residential	23,167	1,749	4,095	0.5%	0.2%	0.6%
C&I	125,409	18,682	8,520	1.5%	0.9%	0.3%
Total	165,430	20,431	12,615	1.2%	0.6%	0.4%

Source: Compiled from the companies’ 2013 IRPs.

Comparing these savings rates to “best practices,” we find that Idaho Power is the only Idaho utility close to the states with the highest savings rates. Table 5 lists the 20 states with the highest energy savings rates, from the American Council for an Energy-Efficient Economy’s 2012 State Energy Efficiency Scorecard (ACEEE 2012). Idaho Power would rank 11th on this list. The State of Idaho ranks 18th.

Table 5. 2011 State Energy Savings by Top 20 States

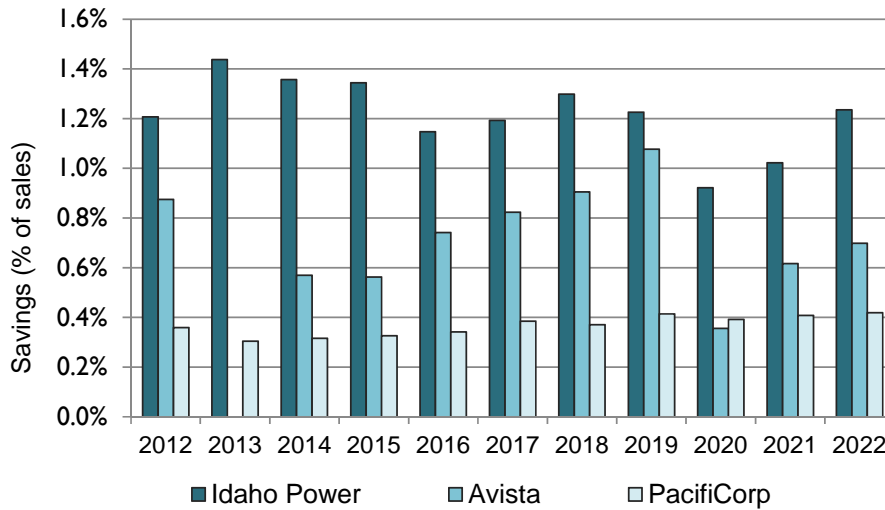
State	2011 Net Incremental Savings (MWh)	% of Retail Sales
1. Vermont	117,940	2.12%
2. Massachusetts	789,894	1.43%
3. Arizona	1,028,378	1.38%
4. California	3,399,300	1.35%
5. Connecticut	394,266	1.32%
6. Hawaii	130,108	1.31%
7. New York	1,791,302	1.25%
8. Rhode Island	96,009	1.25%
9. Ohio	1,880,629	1.22%
10. Minnesota	818,512	1.21%
11. Maine	120,211	1.05%
12. Iowa	475,964	1.04%
13. Pennsylvania	1,553,739	1.04%
14. Michigan	1,000,437	1.00%
15. Oregon	465,211	0.99%
16. Washington	853,253	0.92%
17. Utah	245,308	0.85%
18. Idaho	189,082	0.82%
19. Nevada	250,559	0.74%
20. New Jersey	530,453	0.69%

Source: ACEEE (2012).

In addition, several of the states listed in Table 5 have increased their savings rates since 2011. For example, the Massachusetts utilities collectively achieved electric efficiency savings equal to 2.1% of sales in 2012 (MA EEAC 2013). The programs in Vermont have achieved energy savings of roughly 2% per year for the past five years, achieving 10% cumulative savings over those years (VEIC 2012).

The Idaho utilities' IRPs also project long-term achievable energy savings for their own jurisdictions. Figure 10 below presents actual 2012 savings and the utilities' forecasts of annual incremental savings through 2022. Note that the data for both Idaho Power and Avista include programs in multiple states, but the 2012 starting points for these utilities are similar to the 2012 data for their Idaho operations as presented in Table 4 above.

Figure 10. Projected Annual Incremental Energy Savings (% of Annual Sales)



Source: Compiled from the companies' 2013 DSM studies.

Note that none of the utilities plans to increase its savings level over the planning period. In fact, Avista and PacifiCorp plan to decrease savings rates slightly over the next several years relative to 2012 levels.

These trends reflect a pessimistic view of energy efficiency potential. As shown in Table 6 below, a number of other states that have energy efficiency resource standards (EERS) in place are now requiring increasing savings rates over the next few years. Six of the states in this table will require program administrators to increase their annual incremental savings to 2% or more. In addition, Arkansas mandates that utilities increase savings from a 0.3% level in 2011 to a 0.9% level in 2015. The energy savings ramp-up rate for the entities in Table 6 is 0.22% per year on average.

Table 6. Energy Savings Targets and Ramp Rates for Selected EERS States

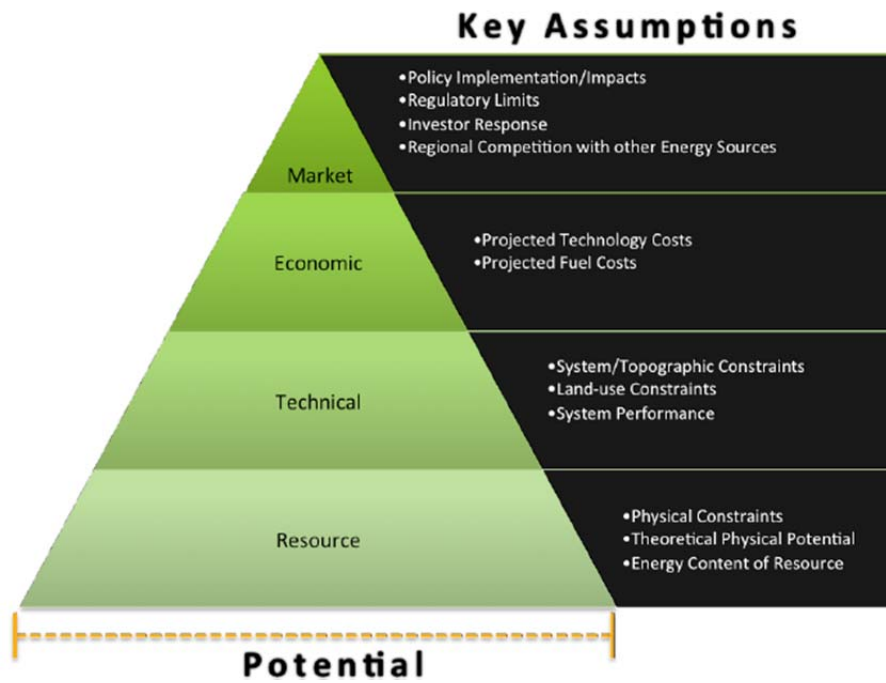
State	Minimum Target		Maximum Target		Climb Time (years)	Annual Average % Increase
	Min	Year	Max	Year		
	a	b	c	d	e=d-b	f=(c-a)/e
Arizona	1.3%	2011	2.5%	2016	5	0.25%
Arkansas	0.3%	2011	0.9%	2015	4	0.16%
Colorado	0.8%	2011	1.7%	2019	8	0.11%
Illinois	0.2%	2008	2.0%	2015	7	0.26%
Indiana	0.3%	2010	2.0%	2019	9	0.19%
Massachusetts	1.4%	2010	2.6%	2015	5	0.24%
Ohio	0.3%	2009	2.0%	2019	10	0.17%
Rhode Island	1.7%	2011	2.5%	2013	2	0.40%
Average						0.22%

Source: ACEEE (2012), Appendix B; Arkansas Public Service Commission, Docket No. 13-002-U, Order No. 7, p. 2.

3. RESOURCE POTENTIALS

A number of different types of efficiency and renewable resource potential are commonly discussed in planning analyses. The diagram below shows the different types of potential commonly analyzed and what these types of potential represent. The base “resource potential” is an unconstrained estimate of the resource based on the theoretical physical potential, such as the total solar energy available annually in a given region. As technical, economic, and market factors are taken into account, the potential of a given technology shrinks.

Figure 11. Levels of Generation Potential with Key Assumptions



Source: NREL (2012). Figure 1.

3.1. Energy Efficiency

Idaho Power and Avista hired EnerNOC to conduct energy efficiency potential studies for their service areas in 2013. In the same year, PacifiCorp hired Cadmus to conduct a potential study on energy efficiency, demand response, and distributed generation. A comparison of these three studies on energy efficiency potential is provided in Table 7. The study results are for the companies’ entire service areas including Idaho and other states; however, we also show PacifiCorp’s results for Idaho only. Energy savings potential estimates are presented as a percentage of forecasted sales over the respective 20-year study periods.

Table 7. Comparison of Efficiency Potential Estimates

	Idaho Power (2030)	Avista (2032)	PacifiCorp (2032)	PacifiCorp - Idaho (2032)
Achievable Potential	13%	10%	12%	13%
Economic Potential	29%	21%	n/a	n/a
Technical Potential	40%	34%	15%	18%

Source: EnerNoc (2013a); EnerNoc (2013b), Cadmus (2013).

The Idaho Power and Avista studies estimate the three types of energy efficiency potential: achievable, economic, and technical potential. In contrast, the PacifiCorp study estimates only achievable and technical potential.⁴

The achievable potential identified in these studies ranges from 10% to 13%. This is significantly below the potential levels identified in studies by other analysts. Table 8 below compares the Idaho companies' achievable potentials to a number of other studies. The average potential in the Idaho studies is just over 12%, while the average in the other studies is 22%, nearly twice the Idaho number. Electricity consumption in Idaho is not likely to differ from that in other places such that the efficiency potential is dramatically lower. Thus, these data strongly suggest that the studies done for the Idaho utilities are understating the efficiency potential.

⁴ In the Cadmus study, the achievable potential is called "achievable technical" potential and is defined as "the portion of technical potential expected to be reasonably achievable in the course of a planning horizon." (Cadmus 2013, p. 63)

Table 8. Comparison of Achievable Potential Estimates

Study	Utility/Region	Study Year	Analysis years	Sector	Achievable Potential	Average
EnerNOC (2013a)	Idaho Power (ID, OR)	2013	22	All	13.4%	12.1%
EnerNOC (2013b)	Avista (ID, WA)	2013	20	All	10.1%	
Cadmus (2013)	PacifiCorp (ID)	2013	20	All	12.7%	
Cadmus (2011)	Puget Sound/WA	2011	20	All	18.0%	22.0%
GDS (2012)	PA	2012	11	All	17.3%	
GDS (2011)	VT	2011	20	All	25.4%	
VEIC (2011)	VT	2011	20	All	33.2%	
KEMA (2010)	CT	2010	10	All	31.0%	
NWPCC (2010)	Pacific Northwest	2010	20	All	22.8%	
ACEEE (2011)	AR	2011	17	All	22.0%	
ACEEE (2009)	PA	2010	18	All	17.7%	
GEP (2011)	TVA	2011	19	All	19.8%	
KEMA (2013)	Xcel/CO	2013	8	All	12.5%	

Note: All studies in this table account for the effects of the federal Energy Independence and Security Act of 2007.

Looking at the technical potential estimates in Table 8, one wonders why PacifiCorp’s technical potential estimates are so far below Idaho Power’s and Avista’s. Table 9 compares the components of Idaho Power’s and PacifiCorp’s technical potential. PacifiCorp’s estimates are smaller in percentage terms across the board, but particularly in HVAC & Envelope and lighting. These differences add up to a very large overall difference. Idaho Power’s technical potential is 50% of the forecasted load in 2032, while PacifiCorp’s potential is only 15% of the 2032 load.

Table 9. Idaho Power and PacifiCorp Residential Technical Potential Estimates

End Use	PacifiCorp - Technical Potential		Idaho Power - Technical Potential	
	MWh	% of Baseline	MWh	% of Baseline
Appliance	265	2%	320	5%
Computer & electronics	137	1%	413	6%
HVAC & Envelope	1,445	13%	1,344	21%
Lighting	201	2%	486	8%
Water heater	324	3%	590	9%
Others	9	0%	59	1%
Grand Total	2,382	15%	3,212	50%

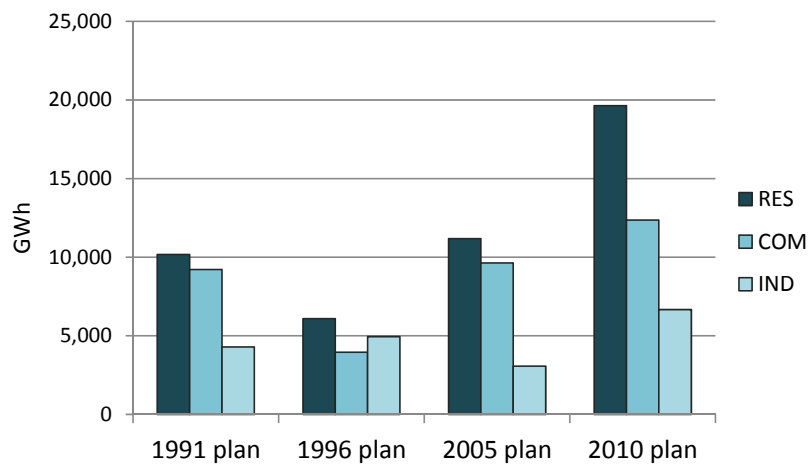
Source: EnerNoc (2013b), Cadmus (2013).

Another striking feature of Table 7 is the extent to which the Idaho Power and Avista studies (both done by EnerNOC) reduce the technical potential in estimating achievable potential. This is done in two steps: using avoided cost assumptions to reduce to economic potential and then applying adoption factors to get to achievable potential. We were not able to review the avoided costs used, although these should not be dramatically different for utilities in the same state. We did, however, compare EnerNOC’s achievable potential screening assumptions to those they used in another recent study and those that Cadmus used for PacifiCorp.

- First, EnerNOC assumes that only about half of the cost-effective measures will be adopted over the course of 13 years. For some measures, such as specialty lighting and water heating, EnerNOC’s adoption rates are only 15% to 30%. However, in a study EnerNOC performed in 2012 for the New Jersey Board of Public Utilities, the adoption rates for residential measures range from 60% to 85% in the study’s achievable high scenario (EnerNOC 2012, Appendix E).
- Second, EnerNOC’s approach for Idaho Power and Avista is very conservative compared with Cadmus’s approach for PacifiCorp. Cadmus adopted NWPCC’s approach, assuming that “by the end of the 20-year assessment horizon, 85% of the technical potential could be achieved, including savings from utility programs, market transformation, and changes in codes and standards” (Cadmus 2013, page 64).

Finally, it is important to note that studies of energy efficiency potential have not generally predicted long-term efficiency potential well in the past. Figure 12 compares the estimated potentials from the NWPCC’s regional energy plans. The potential identified in the 2010 plan is higher than that in the 1991 plan across all sectors. The residential potential nearly doubles from 1991 to 2010. By 2008, the Northwest had saved a total of roughly 30,000 GWh since 1991, greater savings than were thought possible in 1991, and the 2010 potential shown in Figure 12 is the potential for *new* savings, on top of historical savings.

Figure 12. NWPCC’s Energy Efficiency Potential Estimates



Source: Gordon et al. (2008); NWPCC (2010)

3.2. Renewable Resources

The National Renewable Energy Laboratory (NREL) assesses the state-level technical potential of various renewable energy technologies (NREL 2012). Technical potential, as NREL defines it, is the maximum capacity and energy generation that is technically achievable from a particular technology, “given system performance, topographic limitations, environmental, and land-use constraints” (NREL 2012). For the most part, NREL does not take into account important limiting factors, such as “availability of transmission infrastructure, costs, reliability or time-of-dispatch, current or future electricity loads, or relevant policies,” so these estimates do not provide a realistic picture of the resource potential.

Table 10 summarizes the renewable energy potentials NREL estimates for Idaho. The sum of the technical potentials is close to 3,500 GW.

Table 10. Idaho Renewable Energy Technical Potential

Resource	GW	GWh
Urban Utility-Scale PV	12	23,195
Rural Utility-Scale PV	2,045	3,936,848
Rooftop PV	3	4,051
Concentrating Solar Power	1,267	3,502,877
Wind	18	44,320
Biopower	<1	5,958
Conventional Geothermal	2	17,205
Enhanced Geothermal	126	993,257
Hydropower	4	18,758
TOTAL	3,477	8,546,469

Source: NREL (2012).

In reality, a number of factors constrain resource development relative to the technical potential. Opposition encountered in the siting process and the need to integrate variable resources into power systems present constraints. Resource costs and public policy also affect the rate of development. (We compare resource costs in Section 4 below.) A number of recent studies have made it clear that the utility systems in the Western Interconnect can integrate a considerable amount of additional wind and solar generation. For example:

- The **Western Wind and Solar Integration Study**, commissioned by NREL, examined a scenario of 30% wind and 5% solar penetration in the WestConnect region (NREL

2010).⁵ The scenario was examined with several different models focusing on different time scales and aspects of system operation. The study found no negative effects up to 10% renewable energy penetration assuming current operational procedures. There were no effects up to 20% assuming increased cooperation between balancing areas. The 30% scenario required other changes to system operation, including increased sub-hourly scheduling of generation, new transmission and better utilization of transmission, expanded demand response programs, and improved wind forecasting.

- In 2012, NREL published the ***Renewable Energy Futures Study***, in which the Regional Energy Deployment System (ReEDS) capacity expansion model and the GridView hourly production model were used to evaluate system operation under a number of high renewable energy scenarios through 2050 (NREL 2012b). The study concludes that renewable resources could supply 80% of U.S. electricity generation in 2050 and that supply and demand could be balanced at the hourly level. Among the enabling factors identified were: continued transmission expansion, more flexible regional power systems, greater reserve sharing and larger balancing areas.

Below we discuss briefly each renewable technology's potential for Idaho.

Wind

Wind generating capacity has been growing fast in Idaho recently, with 355 MW installed in 2012. There are currently 32 wind projects in the state, representing over 950 MW (AWEA 2013). The technical potential shown in Table 10, based on an assumed 80-meter hub height, is roughly twice Idaho's current annual electricity use.

Advances in wind technology and turbine market dynamics have brought the cost of new wind energy down considerably from its high in 2009-10 (see Section 4 below), making this a very attractive time for Idaho to add wind capacity. The key constraints on long-term development will be land use considerations raised during the siting process and potential wind integration costs. Idaho Power's 2013 *Wind Integration Study Report* projects rising integration costs above about 800 MWs (Idaho Power 2013b). (The company currently accommodates about 680 nameplate MWs.) Critique of this study is beyond the scope of this work; however, it will be important to compare Idaho Power's findings to those of the other integration studies discussed above.

Solar Energy

The technical potential for solar power generation in Idaho is massive. The annual potential shown in Table 10 (roughly 7.5 million GWh summed across the four technologies) is about 370 times the

⁵ The WestConnect region is a subset of the Western Interconnection, including utilities in Arizona, Colorado, Nevada, New Mexico, and Wyoming. The study modeled the entire Western Interconnect, ramping up to 23% wind and solar penetration outside of WestConnect.

state's current annual use. This estimate appropriately excludes many areas of the state.⁶ Further, the historically high cost of photovoltaics (PV) has fallen steeply over the past several years, and states offering PV subsidies have seen substantial growth in this sector. In New Jersey, for example, roughly 400 MW of PV was installed in one year alone.⁷

While the cost of PV projects has fallen recently, the technology remains relatively expensive. A 30% federal tax credit is available to PV projects through 2016; however, this subsidy alone makes PV competitive with new gas plants only at very large scales in the southwestern U.S. A number of states currently offer additional subsidies in the form of tax incentives, renewable portfolio standards, or feed-in tariffs. Unless Idaho adopts a PV subsidy, growth in capacity is likely to remain slow until PV costs fall further.

Concentrating solar power (CSP) is further from commercialization than PV. There are several older projects operating in the U.S. and six projects in various stages of development now (none in Idaho). Five of these projects received federal loan guarantees in order to increase investor confidence in the technology. Experience with these projects—whether they meet cost and performance targets—is likely to be pivotal to the future of CSP. Significant cost reductions will be necessary in order for CSP to be viable. While the solar resource in Idaho could theoretically support CSP plants, to date CSP development has focused exclusively on the Southwest. In addition, the *SunShot Vision Study*, published by the U.S. Department of Energy (DOE) in 2012, includes no CSP in Idaho through 2050.

- The *SunShot Vision Study* explores the extent to which, absent any changes to federal or state subsidies or environmental regulations, a large decrease in the price of solar technologies between 2010 and 2020 would increase solar market penetration over the next several decades (DOE 2012). Assuming that DOE's SunShot cost targets are achieved, the study projects that Idaho would have 500 MW of installed solar photovoltaic panels by 2030, and 1,700 MW by 2050.⁸ As part of this study, researchers used ABB's GridView production cost/power flow model to confirm the operational feasibility of their projections, and detailed a number of near-term, operational strategies to increase the grid's ability to integrate intermittent resources (DOE 2012, p. 19).

⁶ For rural utility-scale projects, the inventory excludes areas with slopes greater than or equal to 3%, federally protected lands, inventoried roadless areas, and areas of critical environmental concern. For the rooftop inventory, usable roof area was extracted from total roof area using an availability factor that accounted for shading, rooftop obstructions, and other constraints.

⁷ Data on New Jersey's installed PV capacity since September 2011 is available at: <http://www.njcleanenergy.com/renewable-energy/project-activity-reports/installation-summary-by-technology/solar-installation-projects>.

⁸ The SunShot cost targets in 2020, expressed in 2010\$, are: utility scale PV at \$1.00 per Watt installed and commercial rooftop PV at \$1.25 per Watt. For Idaho results, see DOE (2012) p. 257.

Geothermal

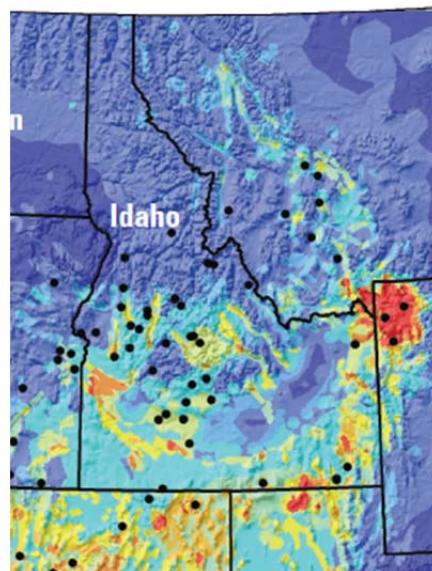
There are three types of conventional geothermal generation: dry steam, flash steam, and binary steam systems. Dry steam geothermal systems use steam directly from the underground resource, so they require the relatively rare phenomenon of steam close to the surface. In flash steam geothermal systems, hot water is pumped up from a geothermal reservoir under high pressure into a tank that is kept at a much lower pressure, causing the hot water to vaporize or “flash” on contact. Binary steam geothermal systems use hot water or steam from the underground reservoir to heat a secondary fluid, which is then used to generate high-pressure steam. Dry steam and flash systems were the first to be developed in the U.S.; however, there are few sites left with a thermal resource amenable to these technologies. Therefore, most new conventional geothermal plants are likely to employ binary technology. (Binary systems account for most of the recent growth in U.S. geothermal capacity.)

The Idaho utilities currently get electricity from three geothermal plants, one of which is in Idaho (Raft River). There are currently eleven projects—including two planned expansions of the Raft River facility—under various stages of development in the state (GEA 2013). If each of these projects were developed to its highest estimated resource potential, it would give Idaho as much as 514 MW of additional geothermal energy.

In addition to conventional geothermal, enhanced geothermal systems are under development. Enhanced geothermal systems (EGS) are systems in which a geothermal reservoir is engineered where conditions are not naturally conducive to conventional geothermal production (usually due to a lack of permeability and water). EGS extracts energy by injecting water under high pressure into hot, dry rock between three and ten kilometers below the Earth’s surface, causing the rock’s natural fractures to widen. The injected water then absorbs the Earth’s internal heat and is pumped back to the surface, where it can be used to generate electricity. Far more land is suitable for EGS than conventional geothermal—even land in the eastern U.S. However, EGS technology is still in its infancy and relatively expensive, and the energy density of EGS is much lower than conventional systems. Production from conventional geothermal can yield 10 to 20 MW per square kilometer, while EGS averages only 0.5 MW per square kilometer (USGS 2008).

As shown in Table 10 above, NREL (2012a) cites a technical potential of roughly 2,000 MW or 17 million MWhs for conventional geothermal. This estimate, which includes both identified sites and undiscovered resources, is based on work done by the U.S. Geological Survey

Figure 13. Conventional Geothermal Resources in Idaho



Source: USGS 2008.

(see USGS 2008).⁹ This work estimates the potential geothermal capacity at identified sites in Idaho to be between 81 and 760 MW, and the capacity at undiscovered sites to be between 427 and 4,937 MW (USGS 2008). Figure 13 shows the identified sites in Idaho (black dots) and the undiscovered potential identified in the USGS assessment (warmer colors indicate greater geothermal favorability).

Very large areas of Idaho are favorable to EGS. NREL (2012a) estimates an EGS resource in Idaho of nearly 1,000 MWhs per year. However, development of this resource will depend on technology maturation and cost reductions. In addition, concerns over water use, induced seismic activity, and other potential impacts of EGS are still being evaluated.

Biomass

There are very few biomass-fired power plants operating in Idaho. We found information on two small plants at sawmills (Stimson Lumber and Tamarack Energy). Further, it appears that the development of new biomass-fired capacity in Idaho will proceed very slowly, absent new policies to encourage projects. The economics of biomass-fired power plants—both power-only and cogeneration plants—are notoriously difficult. First, the cost of getting wood waste out of the forest, grinding it, and transporting it can be quite high per unit of energy delivered. Second, potential investors are very wary of fuel cost risk, and they often require project developers to lock in long-term contracts for a large percentage of the plant's requirements. Project developers are often unable to do so at reasonable costs, killing the project. Finally, power-only plants have conversion efficiencies in the range of 25%, poor relative to other thermal power plants, and it is often difficult to find a steam host with a demand profile suitable for a cogeneration project.

The U.S. Department of Agriculture recently funded a feasibility study of biomass power generation in Boise County. The study concluded that such a plant was not economic given current fuel availability and prices, project costs, and PURPA power purchases rates (McKinstry 2011).

Idaho's biopower potential is not as significant as its other renewable resources. Though animal feeding operations (mainly dairies and beef cattle) continue to grow in southern Idaho, NREL (2012a) has identified a technical potential of less than 1,000 MW in the state. This estimate is based on county-level estimates of the solid biomass resource from crop, forest, and mill residues and urban wood waste. The entire resource is assumed to be used for power generation at an efficiency of 1.1 MWh per ton of biomass. County-level estimates of available biogas focus on animal manure, wastewater treatment, and landfills. The study does not assess the potential from dedicated energy crops; however, the economics of biomass power generation would have to improve considerably to make energy crops competitive with other crops.

⁹ Undiscovered resources are those that have been identified as having the right geological factors (high temperatures, hydrothermal fluid circulation, and permeability) but have not yet been explored.

Hydropower

In 2009, the Idaho Strategic Energy Alliance produced a study presenting the current status and future potential of hydropower in the state (ISEA 2009). The report lists 114 hydroelectric projects operating in Idaho, representing approximately 3,000 MW of capacity. These projects are owned by Idaho's investor-owned utilities, municipalities and cooperatives, independent developers, and federal agencies. Typically, generation by the utilities accounts for about 70% of the state's hydroelectric generation. In addition, in 2009 there were nine small hydropower projects under development in Idaho (ISEA 2009, Appendix B).

Idaho National Laboratory (INL) has released two studies of additional hydropower potential in the state. In 1998, INL assessed "capacity increase" opportunities at specific sites, and in 2006 it estimated the total potential for new hydro in the state based on data from the USGS.

The 1998 study looked at potential new capacity at existing hydropower projects, existing dams without generation equipment, and specific undeveloped sites deemed attractive for development (INL 1998). An initial assessment resulted in 373 potential projects for a total of 7,713 additional MW. The authors then developed environmental, institutional, and legal screening systems to identify the most attractive sites. The screening process reduced the list to 82 projects representing 488 MW. Most of this capacity would come through the addition of generating equipment at dams that do not already have it. Some analysts have speculated that the screening methods applied in this study were overly conservative, resulting in understatement of the developable capacity (ISEA 2009, p. 10).

The INL's 2006 study was a stream-based assessment of the small hydropower opportunity. The authors first used USGS data to identify the gross power potential of all stream reaches in the state and then screened for feasibility of development. They assumed that no new dams would be built, and therefore based estimates of developable potential on small hydro systems using penstocks to divert water through a turbine. The study estimated a potential for about 18,500 GWh per year from new small hydro projects, or about 4000 MW.

Clearly there is a large technical potential for new hydropower in Idaho. The challenges will come in siting projects, where competing water uses and legal issues over water rights and environmental impacts make project development difficult. However, the growing need for energy storage and operational flexibility is likely to increase interest in new hydropower projects. For Idaho in particular, there may be a valuable synergy between water storage needs for irrigation and for power generation. The Idaho Department of Water Resources is studying several reservoir projects that would increase hydroelectric energy storage capacity (ISEA 2009, Appendix C).

3.3. The Mid-Columbia Market

There are two major electricity trading hubs in the Northwest: the Mid-Columbia ("Mid-C") and the California-Oregon Border ("COB"). These are short-term energy markets. That is, energy is traded primarily on an hourly or day-ahead basis, and purchases at these hubs do not convey capacity attributes that can be used to meet resource adequacy requirements. Because of the large amount of

hydroelectric generation in the Northwest, prices in the more northerly Mid-C market tend to be lower than at the COB. Table 11 compares recent energy prices at the two trading hubs.

Table 11. Annual Average Day Ahead On-Peak Energy Prices (nominal \$/MWh)

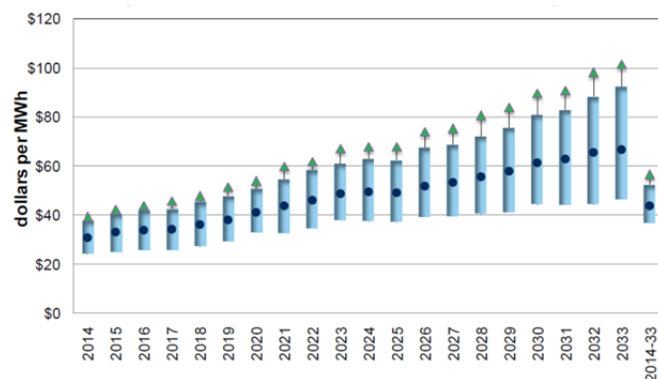
	COB	Mid-C
2006	\$51.68	\$47.98
2007	\$59.86	\$53.59
2008	\$73.42	\$64.48
2009	\$35.40	\$35.25

Source: <http://www.ferc.gov/market-oversight/mkt-electric/northwest.asp#geo>.

Utilities can only use energy from the trading hubs to meet their load requirements if they have access to adequate transmission capacity to deliver the power to their service territory. While all three of the Idaho utilities purchase energy from the Mid-C market, it is not likely that PacifiCorp purchases much Mid-C energy to serve customers in its service territory in southeast Idaho due to transmission constraints. Transmission constraints also limit the amount of energy Idaho Power can purchase from the Mid-C market, and a key rationale for the proposed Boardman to Hemingway transmission line is to give the company greater access to this market.

Mid-C energy is projected to remain low cost relative to other resources throughout the next two decades. For example, Avista presents the results of a price forecasting analysis in which 500 scenarios were examined using different assumptions for inputs such as load, gas prices, forced outages, and wind and hydroelectric generation (Avista 2013). Figure 14 shows the results of this analysis. The dots show the average of the 500 prices forecasted for each year, and the vertical bars show the spread from the 10th to 90th percentile.

Figure 14. Avista Forecast of Mid-C Energy Prices



Source: Avista (2013), Figure 7.13.

While energy purchased through the Mid-C hub is an important resource for the Idaho utilities, it is a short-term energy resource. It does not offer reliable capacity or long-term energy contracts, and these are critical resources for utility resource planning. Utilities must contract for capacity sufficient to meet expected loads plus a reserve margin. They may *hope* that during many high-load hours they will be able to purchase energy at prices lower than the cost of operating their own high-cost peaking resources, but they still must own the right to operate the capacity if needed. Relying too heavily on short-term energy purchases in a resource plan would also expose a utility to unacceptable market

price risk. Therefore, while energy from the Mid-C hub is an important option for minimizing the cost of meeting a company’s load each day, it can only play a limited role in a company’s long-term resource planning.¹⁰

The environmental characteristics of Mid-C energy are not much different from the Idaho utilities’ resource mixes, presented in Section 1 above. As noted, the Washington Department of Commerce calculates the fuel mix of the residual power in the NWPP system after backing out resources committed to specific utilities (such as owned generating units and unit-specific contracts). This mix over the past several years is shown in Table 12.¹¹

Table 12. The NWPP Net System Fuel Mix

	2009	2010	2011	2012
Hydro	34.8%	32.0%	50.0%	47.5%
Coal	44.7%	47.4%	36.9%	35.9%
Biomass	0.8%	1.0%	0.8%	0.6%
Gas	17.5%	16.8%	10.0%	12.4%
Nuclear	1.4%	1.8%	1.3%	2.6%
Other	0.84%	1.0%	1.0%	1.0%

Source: Washington Department of Commerce.

4. RESOURCE COSTS

4.1. Energy Efficiency Costs

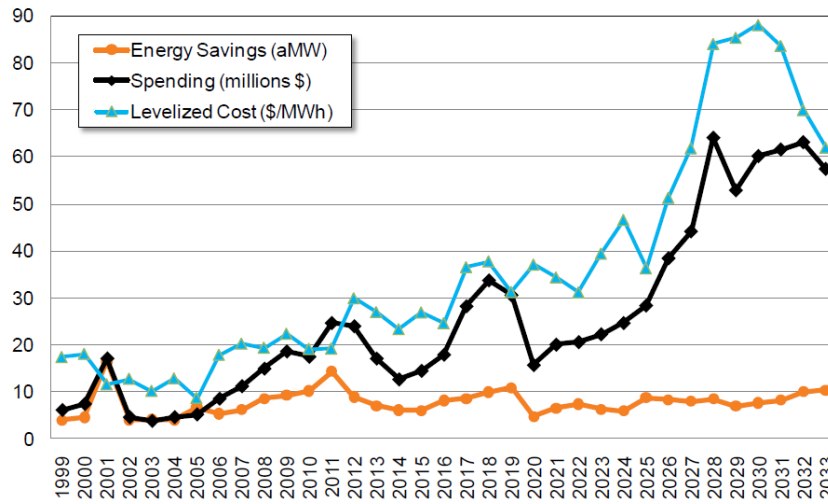
The Idaho utilities’ IRPs present energy efficiency cost data based on their respective potential studies, discussed in Section 2.1. The efficiency costs assumed by both Avista and PacifiCorp are significantly higher than Idaho Power’s cost assumptions and higher than cost levels found in other industry data. Figure 15 presents historical and forecasted data for energy savings, program spending, and the levelized cost of energy for Avista. The company assumes significant cost increases going forward, while they essentially maintain current savings levels. The levelized cost of saved energy doubles from today’s \$20-30 per MWh levels to \$60 per MWh in the future.¹²

¹⁰ Note that if utilities can obtain long-term energy and capacity contracts from resources in the region, coupled with firm transmission rights to deliver the energy, this could constitute a capacity resource for meeting reliability requirements; however, this is different from relying on short-term spot market purchases.

¹¹ See: <http://www.commerce.wa.gov/Programs/Energy/Office/Utilities/Pages/FuelMix.aspx/>.

¹² Figure 15 appears to show total resource costs, including both program costs and participant costs.

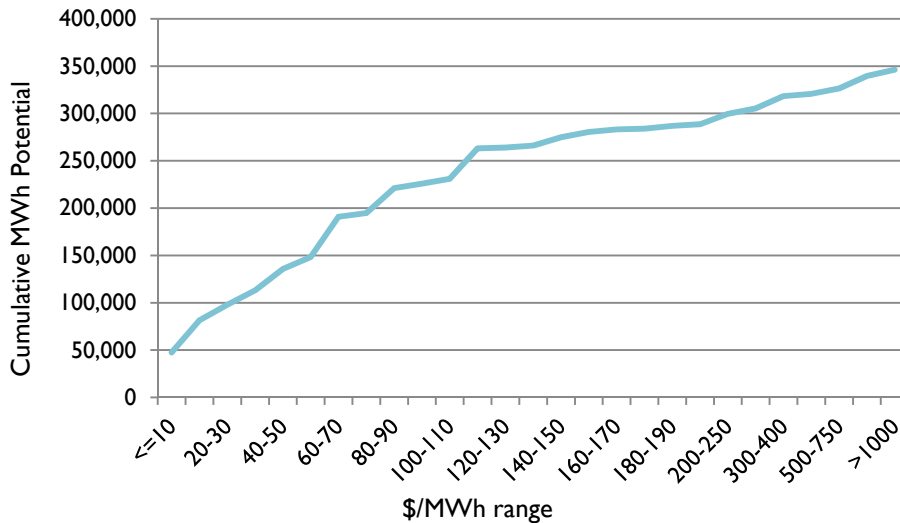
Figure 15. Existing and Future Efficiency Savings for Avista (nominal dollars)



Source: Avista (2013), Figure 3-13.

PacifiCorp also assumes very high costs for energy efficiency. Figure 16 shows that more than half of the company’s energy efficiency potential costs more than \$60 per MWh.

Figure 16. PacifiCorp Efficiency Cost Estimate for Idaho



Source: PacifiCorp (2013), p. 148.

Table 13 below presents Idaho Power’s assumptions for its energy efficiency programs through 2032. The levelized cost of saved energy over the entire period is \$35 per MWh, almost identical to the company’s estimate of current costs.

Table 13. Idaho Power’s Efficiency Cost Estimate

	2032 Load Reduction (aMW)	Resource Costs (20-Year NPV)	Alternate Energy Benefits (20-Year NPV)	Benefit/Cost Ratio	Levelized Costs (\$/MWh)
Industrial/Commercial	157	\$188,245,928	\$467,521,430	2.5	28
Residential	76	\$123,886,346	\$190,935,664	1.5	46
Irrigation	28	\$52,623,496	\$76,220,052	1.4	49
Total	261	\$364,755,770	\$734,677,146	2	35

Source: Idaho Power (2013), p. 43.

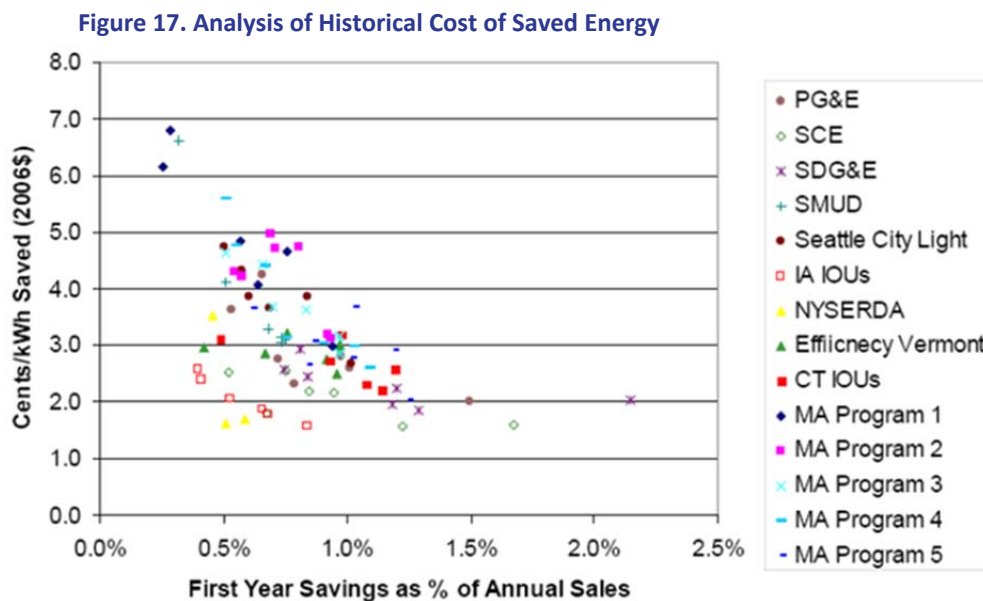
A cursory review of the companies’ assumed measure costs suggests that high measure costs are at least partially responsible for Avista’s and PacifiCorp’s high cost-of-saved-energy assumptions.

- The Avista study assumes an installed cost of \$5,655 for a minisplit heat pump with space heating capability. In contrast, a recent study by the Northeast Energy Efficiency Alliance found that the average installed cost for a minisplit system ranges from \$3,100 to \$4,400, and the average for Idaho cities is about \$3,700 (NEEA 2013).
- The Avista study assumes that a minisplit for cooling costs more than \$4,000 per installation, but the Idaho Power study assumes a similar technology costs about \$1,200 to \$2,600 per installation (EnerNOC 2013a, Appendix B; EnerNOC 2013b, Appendix B).
- The cost of LED light bulbs per single family household is close to \$2,000 in Avista’s study (EnerNOC 2013a, Appendix B). Assuming that all sockets are replaced with LEDs, the cost per bulb is about \$50. However, current prices for standard screw-in LED bulbs range from \$10 to \$20 at retail stores.

Other data support Idaho Power’s view of steady rather than rising efficiency costs over time. In 2009, ACEEE reviewed the cost of saved energy in utility and third-party programs from 14 states, many with savings rates among the nation’s best (ACEEE 2009b). ACEEE concluded that average utility costs (not including participant costs) ranged from \$15 to \$34 per MWh, averaging \$25 per MWh (stated in 2007 dollars). The study also found that the utility typically bears about 55% of the total energy efficiency cost, and customers bear about 45%. Therefore, the total cost of saved energy would be in the range of \$45 per MWh (2007 dollars).

In addition, a study by Synapse analyzed the costs and savings associated with efficiency programs for a total of 14 utilities or third-party administrators—again, entities with some of the highest savings rates in the nation. Figure 17 from that study shows 90 data points, each of which represents the cost of efficiency program activities in one year by one entity. The data suggest that there are in fact

economies of scale associated with more aggressive efficiency efforts: as the percentage of energy saved increases, the average cost of saved energy declines.¹³



Source: Synapse (2008)

4.2. Renewable Resource Costs

The tables below present the three utilities’ renewable energy cost assumptions as well as estimates from other recent, publicly available sources. Wind and PV costs have both fallen considerably over the past several years, so for these resources it is critical to benchmark estimates against current data. For the Idaho utilities, all cost assumptions are from the 2013 IRPs. The “?” symbol in the tables below indicates that we did not find that input assumption in the IRP documents.

Wind

The cost of U.S. wind projects has fallen considerably from its high in 2009-2010. Data on this cost reduction are presented in DOE’s *2012 Wind Technologies Market Report* (DOE 2013). This cost reduction, along with technological advances that have increased capacity factors at new projects, have resulted in very low levelized energy costs for many projects installed in 2013. A number of PPAs were announced in 2013 at prices between \$20 and \$30 per MWh, although most of these were outside the Northwest.

¹³ A more recent study by Plunkett et al. (2012) developed a multi-linear regression model based on numerous historical energy efficiency program data, which revealed that the cost of saved energy falls due to economies of scale until savings reach approximately 2.5% of sales.

Looking at the Idaho utilities' wind cost assumptions, it appears that PacifiCorp has picked up this trend in falling wind costs, while Idaho Power has not. Table 14 compares the three utilities' cost assumptions to several recent, publicly available estimates. None of the estimates in the table includes the effect of the federal Production Tax Credit (PTC), which expired in 2013.

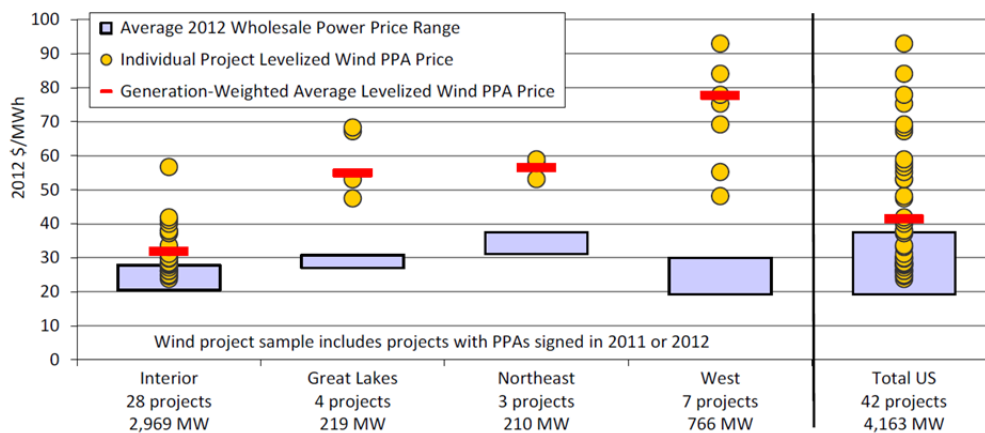
Table 14. Comparison of Wind Cost Assumptions

Source	Project Size (MW)	Installed Cost (\$/kW)	Levelized Cost (\$/MWh)	Capacity Factor	Cite
Idaho Power (2013)	100	\$2,776 - \$3,675	\$169 - \$212	26%	App. C pp. 85, 89
Avista (2013)	?	\$2,340	\$110 - \$122	33% - 34%	Chapter 6
PacifiCorp (2013)	?	\$2,138 - \$2,365	\$65 - \$92	29% - 40%	Tables 6.1, 6.2
Lazard (2013)	100	\$1,500 - \$2,000	\$45 - \$95	30% - 52%	p. 14
Wiser et al. (2012)	?	\$1,600 - \$2,025	\$69 - \$95	32% - 44%	Slides 21, 26, 28
EIA (2013)	?	?	\$87	34%	Table 1

Note: Lazard, Wiser et al. and EIA present national estimates, not Idaho-specific estimates.

Figure 18, from DOE (2013), shows the average prices of seven PPAs signed in the western U.S. in 2011 and 2012. The capacity weighted average rate of the PPAs is below \$80 per MWh. One might expect the companies' forecasted wind costs to be higher than this, since 2011 and 2012 projects benefitted from the PTC. However, loss of the PTC alone cannot explain Idaho Power's high wind cost assumptions. The data in Figure 18 suggest that Avista and PacifiCorp are closer to current actual costs than Idaho Power. It will be important for wind advocates in Idaho to review the 2013 data on PPAs in the Northwest when DOE releases the *2013 Wind Technologies Market Report*.

Figure 18. Levelized Long-Term Wind PPA Prices



Source: DOE (2013).

One obvious problem in Idaho Power's assumptions is the capacity factor. The hub heights and rotor diameters at the projects being installed now are producing capacity factors much higher than 26%,

even in Class 2 wind regimes.¹⁴ For more on this, see Wiser et al (2012). For example, Avista assumes a capacity factor of 38% for the Palouse Wind project (installed in 2012) from which it purchases energy.¹⁵ (This assumption also raises the question: why has Avista assumed a capacity factor of 33% to 34% for future wind projects?)

In sum, the cost and performance of U.S. wind projects was in a rapid transition just before, and possibly while, these 2013 IRPs were being developed. It will be important to ensure that these utilities use up-to-date wind assumptions in their 2015 IRPs.

Solar

The cost of PV projects is expected to fall over the next two decades. Therefore, utilities should use a price forecast with a falling trajectory. In addition, an important assumption within a utility's PV cost forecast is the fate of the 30% Investment Tax Credit (ITC) currently available to PV but falling to 10% in 2016.

PV costs have fallen dramatically since 2008, driven by intense price competition and shrinking margins in the PV module industry. Preliminary data suggest that these cost reductions continued through 2013. While future cost reductions will certainly occur, the rate is likely to slow as reductions will need to come from real manufacturing and balance-of-system cost reductions. The latest empirical data on the installed cost of utility-scale PV, from researchers at Berkeley Labs, puts 2012 costs in the range of \$3,500 per kW (Barbose et al., 2013, Figure 32). However, this study, published in July 2013, warns that the 2012 data presented are not likely to reflect 2013 costs well, given the anecdotal evidence of continuing price declines. Information from press releases and confidential data to which Synapse has access suggest current (winter 2014) national average utility-scale PV costs are well below \$3,500 per kW, perhaps as low as \$3,000 per kW. Given the evidence, we believe that \$3,250 per kW is a conservative though reasonable estimate of current (winter 2013/14), national average, utility-scale PV costs. Therefore, a *forecast* of PV costs for a 20-year IRP should be significantly below this level.

As seen in Table 15, the low ends of Idaho Power's and PacifiCorp's capital cost ranges seem appropriate for near-term PV projects. (PacifiCorp states that its costs are based on a 2014-15 online date.) We would characterize the high end of these ranges, and Avista's assumed cost of \$3,400 per kW, as very high cost projects in the 2014-15 timeframe.

¹⁴ Idaho Power reports that its assumptions for technology cost relied primarily on work done by Black & Veatch for NREL (Idaho Power 2013b, p. 63). However, the capacity factors presented in the Black & Veatch study are considerably higher than Idaho Power's assumed 26%. See Black & Veatch (2012) at Table 29. It is also worth noting that, while Black & Veatch (2012) was released in 2012, the work was done in 2009 and 2010, at the peak of U.S. wind project costs. See Black & Veatch page 3.

¹⁵ On page 2-30 of their 2013 IRP, Avista reports a nameplate capacity of 105 MW and expected energy of 40 aMW.

The capacity factors the companies have used span a reasonable range for projects in and around Idaho. The high ends of Idaho Power’s and PacifiCorp’s ranges probably represent projects outside of Idaho.

Given the companies’ capital cost and capacity factor assumptions, the levelized cost estimates for Idaho Power and PacifiCorp are reasonable. When we enter these inputs into a project cash flow model, with other reasonable inputs, we get levelized costs in a similar range. However, Avista’s levelized costs are much higher than its stated inputs warrant (and as noted, we believe that its stated capital cost is too high). Avista indicates that its range represents projects with 30% and 10% ITCs. However, with a 10% ITC we produced a levelized cost in the low end of Avista’s range, and with a 30% ITC we produced costs well below its range. Avista may be applying a penalty or adder to PV in calculating levelized costs, or it may be assuming an extremely high cost of capital.

Table 15. Comparison of Utility-Scale PV Cost Assumptions

Source	Size (MW)	Forecast Year	Installed Cost (\$/kW)	Levelized Cost (\$/MWh)	Capacity Factor	Cite
Idaho Power (2013)	10	?	\$3,136 - \$3,414	\$133 - \$154	19% - 24%	App. C pp. 85, 89
Avista (2013)	?	?	\$3,403	\$283 - \$374	15%	Chapter 6
PacifiCorp (2013)	2 - 50	2014-15	\$2,952 - \$3,810	\$86 - \$142	22% - 34%	Tables 6.1, 6.2
Lazard (2013)	10	2013	\$2,000 - \$1,750	N/A	N/A	p. 13
EIA (2013)	?	2018	?	\$144	25%	Table 1

Note: Lazard, Wisser et al. and EIA present national estimates, not Idaho-specific estimates.

Table 16 compares various cost assumptions for CSP projects. Avista did not include CSP in its IRP process but did estimate capital costs. Note that both of PacifiCorp’s installed cost assumptions are at the low end of the range defined in the table. Idaho Power does not state whether its levelized cost estimate includes the effects of the ITC. Other than developers’ cost targets, there is no publicly available information from recent CSP projects to benchmark these estimates.

Table 16. Comparison of Concentrating Solar (CSP) Cost Assumptions

Source	Size (MW)	Type	Installed Cost (\$/kW)	Levelized Cost (\$/MWh)	Capacity Factor	Cite
Idaho Power (2013)	100	?	\$6,578 - \$9,360	\$265 - \$290	18% - 28%	App. C pp. 85, 89
Avista (2013)	?	?	\$6,587	?	?	Chapter 6
PacifiCorp (2013)	100	Trough	\$5,072	?	?	Table 6.1
PacifiCorp (2013)	100	Tower	\$4,831 - \$5,796	?	24% - 30%	Table 6.1
Lazard (2013)	110	Tower	\$5,600 - \$9,000	N/A	N/A	p. 13
EIA (2013)	?	?	?	\$262	20%	Table 1



Geothermal

Idaho Power’s geothermal cost assumptions are the highest in Table 17, and Avista’s are the lowest. There is no publicly available data from recent geothermal projects that can be used to benchmark these estimates.

Table 17. Comparison of Geothermal Cost Assumptions

Source	Size (MW)	Installed Cost (\$/kW)	Levelized Cost (\$/MWh)	Capacity Factor	Cite
Idaho Power (2013)	26	\$7,968 – \$8,442	\$142 - \$148	92%	App. C pp. 85, 89
Avista (2013)	15	\$4,767	\$104 - \$107	?	Chapter 6
PacifiCorp (2013)	35 - 43	\$4,795 - \$5,916	?	90%	Table 6.1
PacifiCorp (2013) PPA	30	N/A	\$104	90%	Table 6.2
Lazard (2013)	30	\$4,600 - \$7,250	\$89 - \$142	80% - 90%	p. 14
EIA (2013)	50	?	\$90	92%	Table 1

Biomass

Idaho Power and Avista’s estimates of digester system installed costs are very close. The high end of Avista’s levelized energy range may reflect the addition of a fuel cost, which certain projects could incur. The spread of installed cost estimates for direct-fired woody biomass is also relatively small. To compare the levelized energy estimates in more detail, it would be important to compare the fuel cost assumptions. Idaho Power and Avista do not state whether the PTC is included.

Table 18. Comparison of Biomass Cost Assumptions

Source	Size (MW)	Type	Installed Cost (\$/kW)	Levelized Cost (\$/MWh)	Capacity Factor	Cite
Idaho Power (2013)	50	Digester	\$4,921	\$111	90%	App. C pp. 85, 89
Avista (2013)	5	Digester	\$4,775	\$110 - \$146	?	Chapter 6
Avista (2013)	25	Woody	\$4,436	\$160 - \$162	?	Chapter 6
PacifiCorp (2013)	5	Woody	\$3,334	\$71	91%	Tables 6.1, 6.2
Lazard (2013)	35	Woody	\$3,000 - \$4,000	\$87 - \$116	85%	p. 14
EIA (2013)	20-50	Woody	?	\$111	83%	Table 1

Hydropower

The cost of upgrades to existing hydro projects or dams without generation equipment is highly site-specific, and none of the companies presents upgrade costs in their IRPs. Avista discusses a study of upgrades to its projects on the Spokane River, but does not present estimated costs. Consideration of these potential upgrades is part of the 2013 IRP Action Plan. Idaho Power presents cost assumptions for a new small hydro project (shown in Table 19), but not upgrades to an existing site.

Table 19. Comparison of Hydroelectric Cost Assumptions

Source	Size (MW)	Type	Installed Cost (\$/kW)	Levelized Cost (\$/MWh)	Capacity Factor	IRP Cite
Idaho Power (2013)	10	New	\$4,784	\$144	45%	App. C pp. 85, 89
Avista (2013)				No data presented.		
PacifiCorp (2013)				No data presented.		

5. CONCLUSIONS

We draw the following conclusions from the data reviewed in this study.

- Statewide, roughly 39% of the electricity serving Idaho customers in 2012 was generated outside of Idaho. This estimate assumes that all electricity generated in Idaho goes to serve Idaho customers.
- Approximately 82% of this out-of-state electricity was coal-fired generation.
- Idaho can do much better on energy efficiency. Idaho Power is currently saving energy equal to 1.2% of its sales each year. Avista’s savings rate is 0.6% and PacifiCorp’s is 0.4%. In 2011, 10 states had average savings rates—across all utilities—greater than 1.2% of sales, and many states have improved since 2011.
- Policymakers should carefully review the Idaho utilities’ efficiency cost and potential studies. The 2013 studies for Avista and PacifiCorp assume that costs will rise steeply as energy is saved. The findings of a number of other studies—including Idaho Power’s 2013 study—contradict this assumption.
- The efficiency potential identified in the 2013 studies for the Idaho utilities is considerably lower than that identified by a number of studies for other states and regions.
- Idaho Power’s assumed cost of new wind in the 2013 IRP is significantly higher than Avista’s and PacifiCorp’s and higher than the current literature.
- Avista’s assumed cost of utility-scale PV is significantly higher than Idaho Power’s and PacifiCorp’s and higher than the current literature.
- Idaho Power’s assumed cost of new geothermal capacity in the 2013 IRP is significantly higher than Avista’s and PacifiCorp’s and higher than the literature.
- It does not appear likely that CSP capacity will be developed in Idaho in the near term, and possibly not in the long term either.

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