

Value of Northwest Distributed Solar



February 2015

Acknowledgments

This paper was developed and reviewed by members of the PNUCC System Planning Committee. A special thank you to subgroup members:

Clint Kalich	<i>Avista</i>	Jimmy Lindsay	<i>Portland General Electric</i>
Gordon Matthews	<i>BPA</i>	Tomás Morrissey	<i>PNUCC (lead author)</i>
Terry Toland	<i>Clark PUD</i>	Elizabeth Hossner	<i>Puget Sound Energy</i>
Erin Erben	<i>EWEB</i>	Phillip Popoff	<i>Puget Sound Energy</i>
Adam Rue	<i>EWEB</i>	Michael Jones	<i>Seattle City Light</i>
Phil DeVol	<i>Idaho Power</i>	Michael Little	<i>Seattle City Light</i>
Mark Stokes	<i>Idaho Power</i>	Zac Yanez	<i>Snohomish PUD</i>
Sima Beitinjaneh	<i>Portland General Electric</i>	Dave Warren	<i>WAPUDA</i>
Stefan Brown	<i>Portland General Electric</i>		



101 SW Main Street, Suite 1605
Portland, OR 97204

For further information contact
Tomás Morrissey at tomas@pnucc.org

Electronic copies of this report are available at
www.PNUCC.org



Memorandum

To: PNUCC Board of Directors
From: Phillip Popoff, System Planning Committee Chairman
Date: January 30, 2015
Subject: Report completed – The Value of Solar

For the past year PNUCC's System Planning Committee (Committee) has been studying the value distributed solar power brings to the electric utility. The culmination of the Committee's efforts is represented by this report.

This report examines distributed customer owned solar power holistically, discussing its various value components, including energy, capacity and integration. When possible, the report estimates the value a Northwest utility may see from these components. It also stresses that every utility will see a different value from distributed solar depending on geography, existing resource mix and other factors.

Going forward, the Committee plans to continue to study solar power, both at the customer and utility scale. Solar power is a resource that may play an increasingly important role in the Northwest electric power system, and the Committee will strive to keep PNUCC members informed of the values it brings to the system.

I hope you find this report to be useful. Please direct any questions you may have to Tomás Morrissey at PNUCC – he can be reached at tomas@pnucc.org or 503.294.1259.

Table of Contents

Executive Summary.....	1
Value of Solar Varies by Utility.....	1
Distributed Solar in the Northwest.....	2
Value of Solar Analysis.....	3
Approach.....	3
Energy.....	4
Line Loss.....	5
Peak Capacity.....	5
Other Peak Capacity Considerations.....	6
Transmission Wheeling.....	8
Renewable Portfolio Standards.....	8
Hedge.....	9
Integration.....	10
Transmission Capacity.....	11
Distribution System.....	11
Externalities.....	11
Voltage Control.....	11
Findings Summary.....	12
Value of Solar, West of the Cascades.....	12
Value of Solar, East of the Cascades.....	13
Going Forward.....	14
References.....	15

Executive Summary

A growing number of Northwest homes and small businesses are installing solar panels that generate electricity. The falling costs of solar installations are contributing to the rising interest. When customers produce their own electricity, the amount and characteristics of electricity and services they receive from their utility changes. Understanding these changes will be important as distributed solar generation becomes more prevalent in the Northwest.

To better appreciate the role distributed solar generation can play in the region the PNUCC System Planning Committee undertook a Northwest specific assessment of the values and costs customer owned distributed solar brings to the electric utility. This report discusses those values and costs, and when possible, quantifies them.

Value of Solar Varies by Utility

Every utility will see a different value from solar. This is due to many factors, perhaps most importantly:

- **Geography** – the value of all aspects of solar tends to increase with more sun exposure.
- **Energy prices** – for many utilities the energy value that distributed solar provides is related to the market price of energy.
- **Timing of utility peak demand** – the peak capacity value of solar is determined by the overlap of solar production and utility peak need.
- **Utility characteristics** – the value of solar generation is affected by the different Northwest utilities needs and resource portfolios.

The value each utility will see from customer owned distributed solar varies greatly. This analysis estimates that the value can range from \$33 to \$82 per megawatt hour.

Of the many resource characteristics examined in the analysis, the energy provided by solar panels is of greatest value. For some utilities the peak capacity value can also be significant. The figure to the right shows how these values stack up.¹

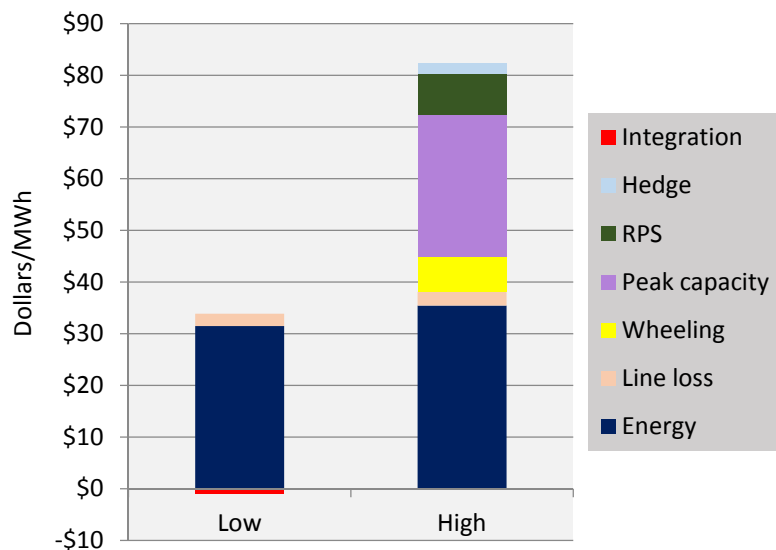


Figure 1 – Example value of solar

¹ There are solar value concepts discussed in this report that were not quantified and do not appear in the figure.

Distributed Solar in the Northwest

The Pacific Northwest has recorded 13,949 distributed net metered solar installations totaling 92 MW of installed capacity through 2013. Table 1 shows distributed net metered solar in each Northwest state by total installed capacity and number of meter connects.² For comparison and scale, California and the US total have been included at the bottom of the table. Note that these data are from 2013 – today these values are likely notably larger.³

State	Installed Capacity (MW)	Number of meters
Idaho	3	428
Montana	8	1,174
Oregon	56	7,596
Washington	26	4,751
NW Total	92	13,949
California	1,978	232,747
US Total	5,139	474,336

Table 1- Net metered solar in 2013

Solar technology is becoming more affordable, which will contribute to increased development in the Northwest. The growing affordability is due to falling capital costs, falling installation costs, various incentives and leasing programs (which reduce the amount of upfront capital needed to install solar). Figure 2 shows the decline in price from 1998 – 2013 for installed solar at the residential and small commercial scale (less than 10kw).

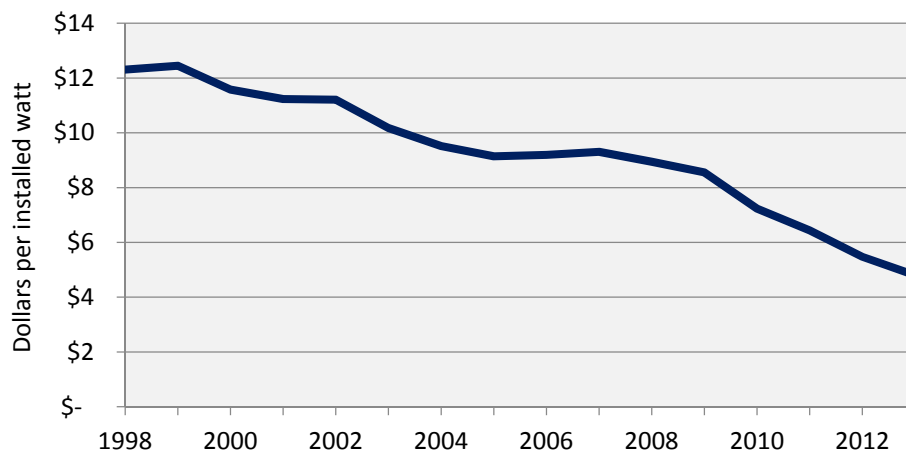


Figure 2 – Installed price per watt⁴

2 EIA form 861 data, 2013. Capacity data are AC load capable MW.

3 2013 data most current EIA data at time of publication.

4 Lawrence Berkeley National Laboratory, 2014. Costs are per watt of DC solar.

Solar exposure in the Northwest varies greatly by geography, as shown in the map below.⁵ For example, a solar system in Boise, Idaho, produces over 40% more energy per year than a similar system in Seattle, Washington, due to greater solar exposure.⁶

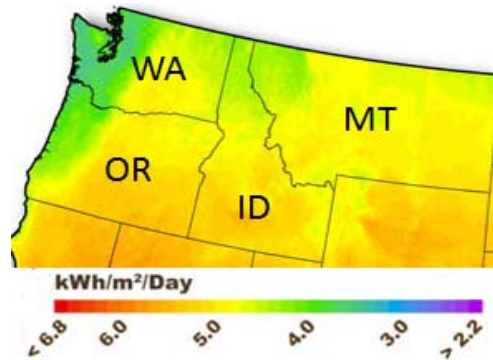


Figure 3 – Northwest Solar exposure

Value of Solar Analysis

Approach

This analysis focuses on values and costs of distributed solar to the electric utility. It breaks these values and costs into various components which are discussed, and if possible, quantified. Quantified values and costs are given as a range because the Northwest has many unique utilities located across a geographically diverse region. As such, the value and cost of each component will differ by utility. Unless otherwise noted 2015 dollars are used in the analysis.

A key assumption in this analysis is that customers – not the utility – bear the capital, installation and maintenance costs related to solar generation. Another assumption is that the solar panels are south facing with a fixed tilt and have a 0.77 DC-AC derate.⁷ The default amount of distributed solar examined in this analysis is 1 MW DC. This is much larger than a typical distributed system and is used for ease of comparison to utility scale resources.

Timeframe

The analysis focuses on the value of solar generation in 2015. Customers who install solar panels typically do not sign long term power purchase agreements with the utility and are not held to reliability standards. Thus the analysis looks at 2015 forecasted market prices rather than a multiyear levelized forecast when valuing energy.⁸

5 Map from National Renewable Energy Laboratory (NREL).

6 PV Watts, a NREL tool for estimating energy production from photovoltaic energy systems.

7 This is the standard orientation, tilt and derate in the NREL PV Watts program. The derate means that 1 MW of DC solar can generate up to 0.77 MW of usable AC power due to losses in the inverter, wiring and other factors.

8 In an October meeting the Northwest Power and Conservation Council, who supplied the forecast for this report, noted that the mid case 2016-2035 levelized Mid-Columbia average price forecast was around \$38 (real, \$2015) whereas the average price in this 2015 analysis is \$33 per MWh.

To assess capacity value and the benefit of reducing renewable portfolio requirements a long term levelized cost analysis was performed. This was done in part because these values are associated with deferring capital projects, which are typically recovered over the life of the facility.

Depending on the system and relationship with the customer, utilities may want to value solar on a one year or multiyear basis.

Energy

During daylight hours solar panels produce energy. This reduces the amount of energy the utility needs to generate or acquire to meet demand. In this analysis energy is the largest value that distributed solar provides.

To calculate this value the analysis uses a 2015 Mid-Columbia market forecast and an hourly solar generation shape.⁹ During each hour of the year the market price of 1 MWh of power is multiplied by the capacity factor of 1 MW of solar during the corresponding hour. This value is summed to create a yearly value for 1 MW of installed solar, and is divided by total yearly solar production to derive an average value per MWh produced.

The table below shows an example calculation for the one day average energy value of 1 MW of solar in July in Portland, Oregon. In this one day example the average energy value is \$39/MWh. In this analysis the one year average value is \$35/MWh.

Time	Market Price/MWh	Energy Produced, MWh	Value
7:00	\$27.43	0.01	\$0.14
8:00	\$31.28	0.19	\$6.00
9:00	\$32.45	0.39	\$12.72
10:00	\$36.52	0.55	\$20.12
11:00	\$41.35	0.65	\$26.84
12:00	\$37.19	0.69	\$25.66
13:00	\$38.05	0.69	\$26.37
14:00	\$40.36	0.67	\$27.04
15:00	\$42.75	0.59	\$25.35
16:00	\$43.39	0.47	\$20.26
17:00	\$43.21	0.29	\$12.70
18:00	\$42.63	0.11	\$4.52
19:00	\$40.65	0.00	\$0.04
One day Total		5.3 MWh	\$207.76
July day average MWh value:		\$207.76/5.3 MWh =	\$39/MWh

Table 2- Example energy value calculation

⁹ Market forecast from the Northwest Power and Conservation Council, 2015 nominal dollars, current policies, normal fuel prices and weather. Solar shapes from NREL PV Watts.

Energy value for Bonneville preference customers

The Bonneville Power Administration (Bonneville) sells preference power to public utilities at \$31.50 per MWh.¹⁰ For full requirements customers, and potentially other public Bonneville customers, this rate may represent the avoided cost of energy, and thus the energy value from distributed solar.

Line Loss

Distributed solar reduces the need for the utility to transmit power from power plants to the service territory. When power is transmitted, some of that power is lost in delivery to the customer. This energy loss is avoided with distributed solar and is a value to the utility. For this analysis, line losses are assumed to be a flat 7.5%.¹¹

Peak Capacity

Distributed solar may provide a peak capacity value to the utility if it defers the need to invest in peaking resources. The figure below shows the capacity factor for distributed solar during an example day. The yellow bars show hourly generation, as a percentage of the installed solar nameplate capacity.¹² If the utility peak need hour consistently occurs when solar power is being produced, and if the utility is capacity deficient, the utility may see a peak capacity value from solar.¹³ For those utilities where this is the case the peak capacity value can be one of the largest values of distributed solar generation.

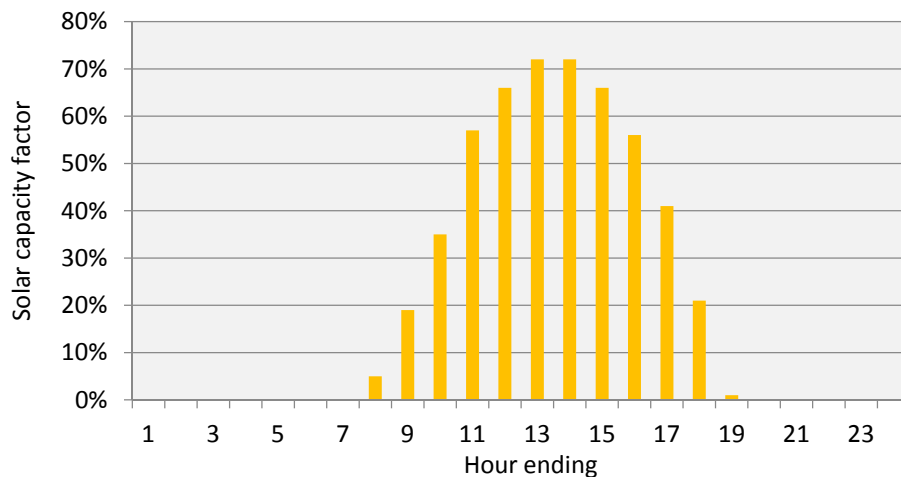


Figure 4 - Example of hourly solar production

10 \$31.50 is the current BPA tier 1 rate through September 2015.

11 US Environmental Protection Agency.

12 Data from PV Watts.

13 A 2014 Idaho Public Utility Commission docket noted that “we find it reasonable for the utilities to only begin payments for capacity at such time that the utility becomes capacity deficient. If a utility is capacity surplus, then capacity is not being avoided by the purchase of QF power.” This quote is in reference to PURPA projects, but the same logic applies toward distributed solar.

Estimating peak capacity value

For this analysis, distributed solar is assigned a peak capacity credit from zero to 28%. Peak capacity credit is defined as the percentage of installed capacity that will reduce peak needs. Zero is the low end of the range since many Northwest utilities, especially winter peaking utilities, will likely not see a capacity value from distributed solar. The 28% value is adapted from draft work in Idaho Power’s 2015 Integrated Resource Plan workgroup process. It represents the estimated high end capacity credit in this report – the actual value seen by utilities will likely differ, and some will see no value at all.

This analysis values the solar peak capacity contribution in comparison to the deferred cost of a new peaking resource, in this case a peaking natural gas plant. Table 3 shows how this is done. The levelized yearly fixed cost per MW for a new natural gas peaking unit in this example is \$100,500.¹⁴ This value is then multiplied by 28%, the peak capacity credit for 1 MW of solar, to arrive at the yearly peak capacity value per MW of solar, \$28,100.

Frame plant w/oil backup	
Capital cost per MW	\$910,200
Discount rate/weighted cost of capital	7.0%
Fixed O&M cost per MW/yr	\$16,300
Unit lifespan, years	30
Forced outage rate	5.0%
Line loss	7.5%
Cost per MW/yr	\$100,500
Solar peak capacity credit	28%
Solar capacity value per MW/yr	\$28,100

Table 3 – Peak capacity value calculation

Other Peak Capacity Considerations

Valuing the peak capacity contribution of solar is not cut and dried. Every utility will see a different value due to many factors, including season of peak power need and existing resource portfolio. This section discusses many of the factors that need to be considered when calculating the peak capacity value of a solar resource.

Season and time of peak

In order for a utility to see a peak capacity value from solar, the hours of greatest power need must reliably coincide with hours of solar production. Many summer peaking utilities will see a peak capacity value from solar since the hour of highest power need often occurs during a daylight hour. Winter peaking utilities may not have a peak capacity solar value since their highest load hour often occurs in the early morning or evening, when there is little or no sunshine.

¹⁴ Frame cost data from draft 2015 Puget Sound Energy IRP work. Under some market conditions a frame unit may provide some energy and/or ancillary service values. For simplicity, these values were not netted out in this calculation.

Solar panel angle and capacity value

The angle at which solar panels are installed can affect how much energy they produce during a peak load hour. Today, most customer owned panels are angled south to maximize energy production.¹⁵ Southwest facing panels, however, provide better capacity for evening peaking utilities. Utilities with a morning peak may see increased capacity from southeast facing solar. In other words, the peak capacity value of solar will vary depending on the angle of the panels.

The difference in peak capacity credit due to solar panel angle can be significant. While examining the peak hour contribution of solar power over the top 150 load hours of a three year study, Idaho Power found that southwest angled solar provided around 60% more peak capacity than south angled solar.¹⁶

Diminishing returns to solar capacity value

As the amount of distributed solar on a utility's system grows, the capacity value of the next increment of solar added may decrease or go to zero. Solar typically provides a capacity value if the utility's peak load net of solar occurs during a solar-producing hour. If enough solar is installed, the peak load net of solar may shift to a non-solar producing hour. At this point, additional solar may not provide a capacity value.

The figure below illustrates this concept. The black line is an example load during a high demand July day.¹⁷ The other lines show the same load net of various amounts of solar.¹⁸

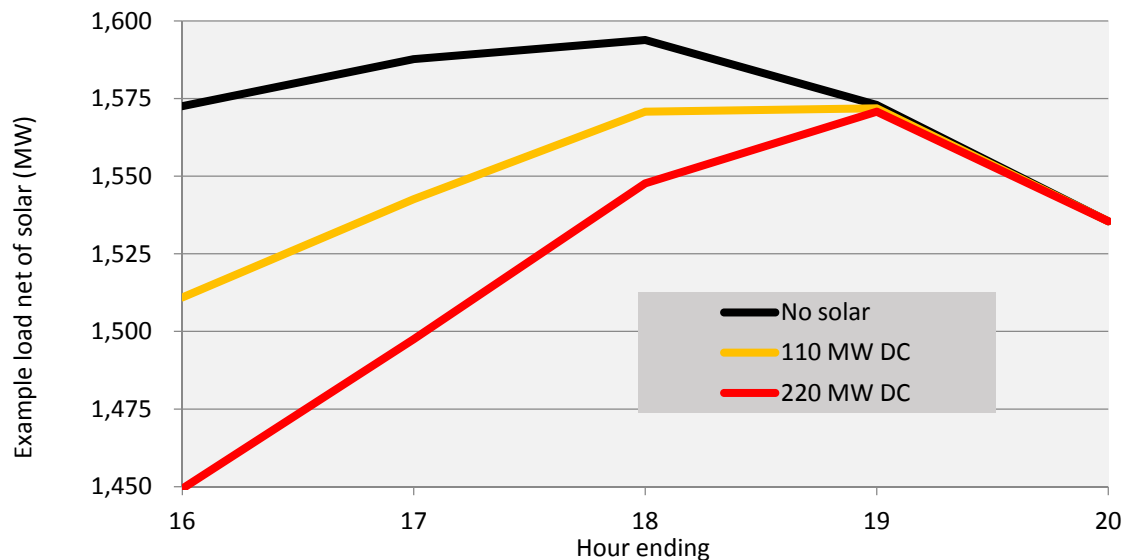


Figure 5 – Shifting load net of solar

15 New York Times, 2014.

16 Draft work for Idaho Power's 2015 Integrated Resource Plan. This result will vary by utility and by study.

17 BPA load data scaled down 5x.

18 PV Watts.

Looking at Figure 5, adding 110 MW of solar generation reduces the peak load net of solar by 22 MW. It also shifts the peak load net of solar from hour ending 18 to hour ending 19. New solar added to the system will now have little effect on the peak load net of solar since there is little solar production in hour ending 19.¹⁹ In this example, 110 MW of solar has nearly the same impact on peak load net of solar as 220 MW of solar.

Storing solar power may increase peaking capability

Northwest utilities may be able to augment the peaking ability of the hydroelectric system via distributed solar. Theoretically, this could be done by storing energy produced from solar during the day in reservoirs and then releasing the water during peak hours. The ability to store solar energy using the hydroelectric system depends on various factors including dam/reservoir type and other hydro functions (such as flood control, ecosystem functions and resource integration). The concept of storing solar energy in the hydro system was not explored quantitatively in this analysis nor is it a possibility for all Northwest utilities.

Remarketing surplus summer capacity

Some utilities may see a value in remarketing increased summer capacity resulting from distributed solar. For example, a winter peaking utility may sell increased summer peak capacity to a summer peaking utility. Peak hour capacity is not frequently sold in the Northwest and this concept is not quantified in the report.

Transmission Wheeling

The amount of high voltage transmission services a utility must reserve might be reduced if distributed solar decreases peak demand. Utilities typically purchase transmission rights based on their peak load needs, so this value likely only pertains to utilities that see a reduction in peak load due to distributed solar. Similar to peak capacity value, this value applies primarily to select summer peaking utilities.

The low end value for this component is zero, since many Northwest utilities will not see decreased transmission need. The high end of the range is a 28% credit, similar to the 28% credit used for peak capacity value. This is valued against the Bonneville network integration charge of \$24,500 per MW per year, which results in a value of \$6,900 per MW per year of solar.

Renewable Portfolio Standards

Montana, Oregon and Washington have renewables portfolio standards (RPS) that require utilities to match a certain percentage of their sales with renewable energy credits. If sales decrease due to solar, the number of renewable energy credits needed for compliance decrease as well.

In this analysis, the value of distributed solar power's contribution to the reduced need for RPS compliance is presented as a range. The low end of the range is zero since some utilities are not subject to RPS or do not have a need for new resources/renewable energy credits. These utilities would not see a benefit from reduced sales.

¹⁹ Assume the solar installation is at the same, south-facing angle. Southwest facing (or tracking) solar would likely provide more capacity later into the evening. However, the same issue would occur as more southwest solar is added and the peak load is shifted fully into a nighttime hour.

The high end of the range represents the avoided cost of the construction of new renewable resources to comply with a RPS.²⁰ Readers should note that some utilities are able to meet RPS using purchased renewable energy credits, which today is likely a less expensive compliance option than building new renewable resources.

An example valuation of reducing the need to comply with RPS is presented below, using wind power as the avoided new renewable resource and 15% as the RPS.

Levelized cost per MWh, new wind power	\$87
Average market price, 2015	\$33
Capacity value	\$3
Net cost	\$52
Renewable requirement per MWh sold	15%
Avoided cost per MWh of reduced sales	\$8

Table 4 – Reduced renewable portfolio standard compliance need value

Assessing reduced RPS need on a two meter system

Distributed solar reduces sales if the customer has one meter, since it slows the meter/moves the meter backwards. Distributed solar can also be installed on a second meter, rather than on the primary meter. In this setup, the sales meter operates normally and the power produced by solar is fed back onto the grid via the second meter. As such, a utility might not see decreased sales nor decreased need to meet a RPS.

Under the two meter setup, a utility may see a value from distributed solar generating renewable energy credits. This value could be attributable in all states, even those without a renewable portfolio standard (if the utility can sell the credits out of state). The value of a renewable energy credit varies – this report uses a range of \$1 to \$5 per MWh.²¹

Hedge

By reducing sales solar generation can decrease exposure to power and fuel markets. A reduction in market exposure may insulate the utility from potentially volatile market prices and reduce the amount of financial hedging the utility performs.

In Minnesota, Xcel Energy, a utility, has stated that there is no hedge value from solar power unless utilities are actively hedging against power and fuel markets, and the active hedging programs are reduced due to solar. However, studies have indicated that there is a power/fuel hedge value to solar and that even passive hedging with solar may have a value.²²

A hedge value of zero to \$2 per MWh is used in this analysis. The low value assumes some utilities will not see a hedge value for various reasons, including not having market exposure. The high value is

²⁰ Wind cost data from draft 2015 Puget Sound Energy IRP work.

²¹ Oregon Public Utility Commission, 2012.

²² NREL.

based off the energy efficiency risk premium used in Avista’s 2013 IRP. Avista used this value to account for both “RPS and rate volatility reductions” over a 20-year timeframe.

Integration

If a customer’s solar installation generates more power than the customer needs, the excess generation can flow back onto the grid. In this case, the utility will need to integrate the power into its system. This would likely lead to additional costs for the utility. A utility may need, for example, to carry additional reserves on its system.

A recent Duke Energy study found that the cost to integrate solar on its system ranged from \$1 to \$10 per MWh, depending on the amount of solar being added. This study examined costs due to reduced fuel efficiency and higher maintenance costs due to increased ramping and reserves. The study discussed, but did not quantify, the cost of building new generation to integrate solar power.

Idaho Power published a solar integration cost study in June 2014. The study focused on the cost of operating Idaho Power’s system differently to integrate solar and did not quantify the cost of building new generation for integration. Idaho Power estimated that the cost of integrating utility scale solar power ranged from less than \$0.50 to over \$4 per MWh.

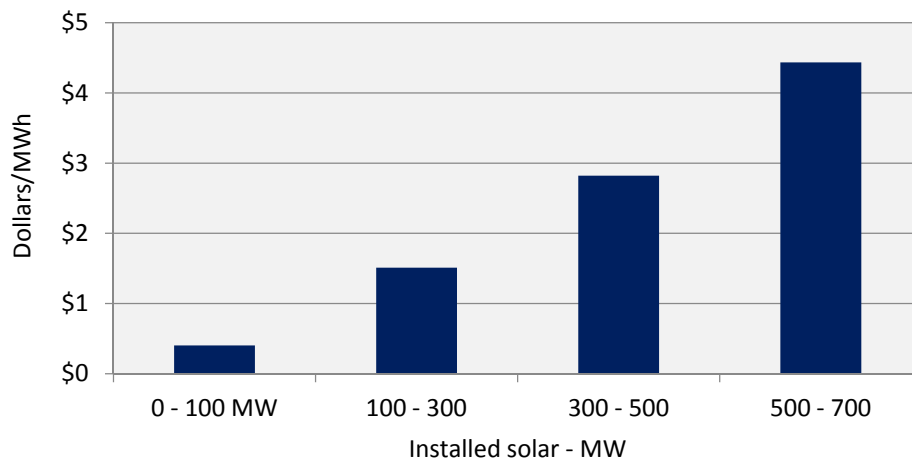


Figure 6 - Idaho Power incremental solar integration cost

Bonneville currently charges \$0.21 cents per kw/month for utility scale solar integration, plus the cost of power purchases for balancing. This fee varies per MWh based on solar capacity factor. For example, solar with a 10% annual capacity factor will see an integration fee of nearly \$3 per MWh, whereas solar with a 20% annual capacity factor will see an integration fee of around \$1.50 per MWh (assuming there are no purchases made for balancing).

Given the relatively low levels of solar currently in the Northwest, this analysis uses a range of \$0 to \$1 for the cost of integrating distributed solar. This cost will likely increase as solar becomes more prevalent in the Northwest.

Transmission Capacity

By reducing load, distributed solar could reduce the need to build transmission lines. This reduced need would be a value to the electric utility.

This value is difficult to quantify since it depends on transmission line congestion. For example, if distributed solar is built in an area with congested transmission, and if it offsets peak transmission use, then it may have an avoided transmission value. However, if distributed solar is built in an area that has latent transmission capacity, or if it does not offset peak transmission use, then it may not have an avoided transmission capacity value.

Due to the factors discussed above, transmission value was not quantified in this analysis.

Distribution System

Some utilities may see a value in decreased distribution system costs from distributed solar. For example, solar may reduce demand on a circuit and thus delay a substation upgrade. If the circuit has a peak that does not coincide with solar production, solar would likely not provide a value.

Solar may also increase distribution costs. At high levels of distributed solar development peak production could become higher than peak consumption. The utility may then have to upgrade the system to handle the power outflow.

The distribution capacity value/cost is applicable on a circuit-by-circuit basis and is not quantified in this analysis.

Externalities

This analysis examines the value a utility sees from customer owned distributed solar generation from a utility perspective, not a societal perspective. For that reason, no values or costs are quantified for externalities.

Voltage Control

Duke Energy's solar integration study discussed earlier indicates that increased solar development can lead to increased high voltage violation events and decreased low voltage events. If voltage violations increase there may be a cost to the utility, if they decrease the utility may see a value.

This cost/value is not quantified in this analysis.

Findings Summary

This section summarizes and tabulates the various components of the value of solar discussed in the report. The values are tabulated for both west of the Cascades and east of the Cascades utilities because of the significant difference in solar exposure. A range of values is provided for each component to show how each Northwest utility may see different values and costs from distributed solar.

Value of Solar, West of the Cascades

The table below shows the value of south-facing solar to an Oregon utility west of the Cascades. It is constructed using a Portland, Oregon, solar shape.

Energy is the largest value component in this calculation, followed by peak capacity and reduced RPS need. Note that most Northwest utilities west of the Cascades are winter peaking and will likely see little to no peak capacity value from distributed solar.

Component	1 MW DC, yearly	Per MWh
Energy	\$32,100 to \$36,100	\$32 to \$35
Line loss	\$2,400 to \$2,700	\$2 to \$3
Wheeling	\$0 to \$6,900	\$0 to \$7
Peak capacity	\$0 to \$28,100	\$0 to \$28
Renewable portfolio standard	\$0 to \$7,900	\$0 to \$8
Hedge	\$0 to \$2,000	\$0 to \$2
Integration	(\$1,000) to \$0	(\$1) to \$0
Transmission capacity	-	-
Distribution system	-	-
Externalities	-	-
Voltage control	-	-
Total	\$33,500 to \$83,800	\$33 to \$82

Table 5 – Estimated value of solar, Oregon utility, west of Cascades

The peak capacity and wheeling values are derived by dividing the 1 MW yearly value by the amount of MWh produced in a year (in this case 1,018 MWh). This value is based on the size of the solar installation and the timing of peak need, not MWh production.

Value of Solar, East of the Cascades

The table below shows the value of south-facing solar for an Idaho utility. It is constructed using a Boise, Idaho, solar shape.

Energy is the largest value component in this calculation followed by peak capacity value. Note that some components are not applicable to all utilities.

Component	1 MW DC, yearly	Per MWh
Energy	\$43,000 to \$48,500	\$32 to \$35
Line loss	\$3,200 to \$3,600	\$2 to \$3
Wheeling	\$0 to \$6,900	\$0 to \$5
Peak capacity	\$0 to \$28,100	\$0 to \$21
Renewable portfolio standard	\$0 to \$6,800	\$0 to \$5
Hedge	\$0 to \$2,700	\$0 to \$2
Integration	(\$1,400) to \$0	(\$1) to \$0
Transmission capacity	-	-
Distribution system	-	-
Externalities	-	-
Voltage control	-	-
Total	\$44,900 to \$96,700	\$33 to \$71

Table 6 – Estimated value of solar, Idaho utility

The peak capacity and wheeling values are derived by dividing the 1 MW yearly value by the amount of MWh produced in a year (in this case 1,366 MWh). This value is based on the size of the solar installation and the timing of peak need, not MWh production.

Going Forward

The price of distributed solar is falling and some areas of the Northwest have aggressive solar incentives. A quick look to California shows how rapidly distributed solar can be developed once prices, incentives and other factors align. Idaho Power, whose service territory has greater solar exposure compared to most of the Northwest, has hundreds of megawatts of utility-scale solar potentially coming online as soon as 2016.²³

A better understanding of distributed solar will help stimulate discussion of appropriate incentives for its development and how to value the power it produces, as well as the other benefits it can provide. PNUCC hopes this report will enhance the examination of distributed solar generation in the Northwest.

Lastly, distributed solar generation changes the traditional utility-customer dynamic. It is important for utilities to realize that solar can provide more than just energy to the grid, and it is important for customers to realize the grid provides them with more than just energy. PNUCC will continue to explore the value and role of solar power in the Northwest, and how customer owned generation affects the utility business model, in future meetings and reports.

²³ These projects are being developed via the Public Utility Regulatory Policies Act.

References

- Avista. “2013 Electric Integrated Resource Plan.” 2013. Accessed via: https://www.avistautilities.com/inside/resources/irp/electric/Documents/Avista_2013_Electric_IRP_Final.pdf
- Bonneville Power Administration. “2014 Transmission, Ancillary and Control Area Service Rate Schedules and General Rate Schedule Provisions (FY 2014-2015). 2013. Accessed via: [http://www.bpa.gov/Finance/RateInformation/RatesInfoTransmission/2014%20Transmission%20Rate%20Schedules\(FINAL\).pdf](http://www.bpa.gov/Finance/RateInformation/RatesInfoTransmission/2014%20Transmission%20Rate%20Schedules(FINAL).pdf)
- Bonneville Power Administration. ““Average” Power Rates, Effective October 1, 2013 – September 30, 2015.” Accessed online in 2014 via: <http://www.bpa.gov/power/psp/rates/current.shtml>
- Bonneville Power Administration. “WIND GENERATION & Total Load in the BPA Balancing Authority. “Data for BPA Balancing Authority Total Load, Wind Gen, Wind Forecast, Hydro, Thermal, and Net Interchange.” Data files on website accessed in 2014 via: <http://transmission.bpa.gov/Business/Operations/Wind/>
- BLS. “CPI Inflation Calculator.” Accessed in 2014 via: http://www.bls.gov/data/inflation_calculator.htm
- E3. “Investigating a Higher Renewables Portfolio Standard in California.” 2014. Accessed via: https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf
- The Economist. “Retail sales, producer prices, wages and exchange rates.” December 2014. Accessed online via: <http://www.economist.com/news/markets-and-data/21635448-retail-sales-producer-prices-wages-and-exchange-rates?zid=295&ah=0bca374e65f2354d553956ea65f756e0>
- Energy Information Administration. “Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files.” 2013 data released in 2015. Accessed via: <http://www.eia.gov/electricity/data/eia861/>
- Environmental Protection Agency. “Clean Power Plan Proposed Rule Technical Documents – Technical Support Document: Goal Computation, Data File: Goal Computation – Appendix 1 and 2 (XLS).” 2014. Accessed via: <http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents>
- Excel Energy. Comments on the Minnesota Draft Value of Solar Methodology. 2013. Accessed via: https://mn.gov/commerce/energy/images/Xcel_VOS-Comments_20131210.pdf
- Idaho Power. Draft 2015 integrated resource plan data accessed via: https://www.idahopower.com/AboutUs/PlanningForFuture/irp/2015/IRPAC_Materials.cfm
- Idaho Power. “Solar Integration Study Report.” 2014. Accessed via: <https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/solar/SolarIntegrationStudy.pdf>
- Idaho Public Utilities Commissions. “Case NO. IPC-E-14-22, Order NO. 33159.” 2014. Accessed via: http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1422/ordnotc/20141029FINAL_ORDER_NO_33159.PDF

Lawrence Berkley National Lab. "Tracking the Sun VII: A Historical Summary of the Installed Price of Photovoltaics in the United States from 1988-2013, Data File XLS." 2014. Accessed via: <http://emp.lbl.gov/publications/tracking-sun-vii-historical-summary-installed-price-photovoltaics-united-states-1998-20>

National Renewable Energy Laboratory. "PV Watts," online tool. Accessed in 2014 via: <http://rredc.nrel.gov/solar/calculators/pvwatts/version1/>

National Renewable Energy Laboratory. "Dynamic Maps, GIS Data, & Analysis Tools. Online graphic, accessed in 2014 via: <http://www.nrel.gov/gis/solar.html>

National Renewable Energy Laboratory. "The Use of Solar and Wind as a Physical Hedge against Price Variability within a Generation Portfolio." 2013. Accessed via: <http://www.nrel.gov/docs/fy13osti/59065.pdf>

The New York Times. "How Grid Efficiency Went South." October 7, 2014. Accessed via: <http://www.nytimes.com/2014/10/08/business/energy-environment/how-grid-efficiency-went-south.html? r=1>

Northwest Power and Conservation Council. Mid-C 2015 Hourly Price, provided by Steve Simmons. 2014.

Oregon Public Utility Commission. Order NO. 12 375. 2012. Accessed via: <http://apps.puc.state.or.us/orders/2012ords/12-375.pdf>

Pacific Northwest National Laboratory. "Duke Energy Photovoltaic Integration Study: Carolinas Services Areas." 2014. Accessed via: http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23226.pdf

Puget Sound Energy. Draft 2015 integrated resource plan data. "2015 IRP Electric Supply-Side Resources (Draft 9/25/14)." Data accessed via: https://pse.com/aboutpse/EnergySupply/Documents/IRPAG_2015-Electric-Resource-Alternatives.pdf

SEIA and GTM research. "U.S. Solar Market Insight Report, 2013 Year-in-Review, Executive Summary." 2014. Accessed via: <http://www.seia.org/sites/default/files/resources/5jBprenCY92013ye.pdf>