DISTRIBUTED SOLAR

Contents

As part of PSE's continuing exploration of emerging resources, the 2015 IRP looks at the impacts of high penetration of rooftop solar installations on both the distribution system and on resource builds. Distributed solar generation has never been selected in the portfolio analysis as a cost-effective resource for the PSE system, but federal tax credits and state production incentives have made it cost-effective for customers. Already, PSE has 2,800 net-metered customers who have installed rooftop solar panels totaling 17.4 megawatts of capacity and 17,360 megawatt hours of annual energy, and we expect many more customers will install solar panels in the future.

OVERVIEW

This appendix includes the details and results from two studies.

The **Distributed Photovoltaic Technical and Market Potential** study is a system-wide study prepared by the Cadmus group that explores the maximum potential for rooftop solar within the PSE system. It asks how much distributed solar might be added to the system in two scenarios:

a) if federal and state incentives are renewed, and
b) if incentives are allowed to sunset.

This information was used as an input in the IRP portfolio analysis. The results of the portfolio analysis are discussed in Chapter 6 and in Appendix N: Electric Analysis. *The Cadmus report on the study appears at the end of this chapter.*

The second study, **Distributed Solar PV Impact at the Circuit Level**, investigates the impact that significant amounts of photovoltaic (PV) generation will have at the circuit level of the electric distribution system, particularly with regard to voltage impacts, peak demand and line losses. *This study description begins on the following page.*

DISTRIBUTED SOLAR PV IMPACT AT THE CIRCUIT LEVEL

Rooftop solar requires the existing energy system – which is built for one-way traffic (system to user) – to accommodate two-way traffic (system to user and user to system). This study looks at how this shift impacts the system.

Study Design and Assumptions

PSE analyzed three effects in particular:

VOLTAGE DROP. Does the interconnection of distributed solar generation change PSE's ability to deliver energy at a voltage that stays within the range of acceptability (114 to126 volts)?

PEAK DEMAND. Can distributed solar generation contribute to meeting peak need by reducing system load at times of peak demand?

LINE LOSSES. Does PV generation increase or decrease line losses beyond expected, base-level loss?

Circuits. Four circuits were chosen for the study. They represent different mixes of residential and commercial buildings, different feeder line lengths and different peak seasons. These are described in Figure M-1.

Figure M-1: Circuits Studied for PV Impact

Circuit ID	Location	Load Mix	Peak Season	Current # Net Meters	2014 Penetration	Length	Current Conditions
Carolina-15 (CAR-15)	Bellingham	76% Commercial 24% Residential	Winter	13	1.7%	1.5 mi	Downtown with most net meters of any commercial feeder.
Union Hill-21 (UHL-21)	Redmond	29% Commercial 71% Residential	Winter	77	4.3%	5.3 mi	Fairly heavily loaded longer feeder. Mostly residential.
Winslow-16 (WIN-16)	Bainbridge Island	51% Commercial 49% Residential	Winter	20	39%	1.0 mi	Lightly loaded short feeder with high solar penetration rate.
Evergreen-17 (EVE-17)	Redmond	100% Commercial	Summer	0	0%	0.6 mi	One of few summer-peaking feeders.

Design Days. Each circuit was studied for a winter design day and a summer design day. For each of these, maximum and minimum sun radiation days and maximum and minimum loads were identified using 2013 data selected at three-minute intervals. Together these variables established eight studies for each circuit.

LOADS

- Light Winter: winter day with lowest peak for 2013
- Heavy Winter: winter day with highest peak for 2013
- Light Summer: summer day with lowest peak for 2013
- Heavy Summer: summer day with highest peak for 2013

SOLAR RADIATION

- Summer Low Sun: day with lowest amount of sun in summer
- Summer High Sun: day with most amount of sun in summer
- Winter Low Sun: day with lowest amount of sun in winter
- Winter High Sun: day with highest amount of sun in winter

Finally, the study created a base case that assumed no solar generation. This added another study for each circuit.

Solar PV Penetration Potential. High technical potentials are assumed, since the purpose of the study is to consider the impact of high levels of solar penetration at the circuit level.

- For residential customers, 40 percent of houses are assumed to have PV systems capable of generating 5 kilowatts per house.
- For existing commercial buildings, 70 percent of roof space is assumed to be available for PV, with equipment capable of generating 15 Watts per square foot, limited to 200 kW per building.

These assumptions are at the high end of the reasonable range, and in some circuits they produce penetration that is greater than 100 percent of peak.[1] Current U.S. standards call for a system impact study when circuits reach 15 percent PV penetration, and they recommend penetration should not exceed 30 percent. The table below shows the peak capacity for each circuit, the penetration potential based on these assumptions, and the 30 percent and 15 percent penetration levels for comparison.

Figure M-2: Maximum Potential PV Penetration for Circuits Studied

Circuit ID	Peak Load MW	Max Potential PV in MW Com+Res=Total			Max Potential Penetration	30% Penetration MW	15% Penetration MW
CAR-15	4.2	4.6	1.1	5.7	135%	1.26	0.63
UHL-21	7.6	1.1	5.1	6.2	82%	2.28	1.14
WIN-16	0.6	0.3	0.1	0.4	67%	0.18	0.09
EVE-17	6.5	0.6	0.0	0.6	9%	1.95	0.975

Circuit Profiles. The following pairs of charts show how these assumptions translate into daily load curves and PV potential for each circuit. The daily load curve charts illustrate how demand on the circuit varies with seasonal conditions (heavy summer, light summer, heavy winter and light winter). The potential PV generation charts show how PV generation varies on the circuit under different solar radiation conditions (low sun summer, high sun summer, low sun winter and high sun winter). This is the basic information used to analyze each circuit.

TO READ THE CHARTS ON THE FOLLOWING PAGES: Note that the vertical axis scales differ from chart to chart. All charts use the same 24-hour timeline for the horizontal axis.

1 / PV penetration as a percentage is determined by dividing the total capacity of PV systems on the circuit (in KW) by the peak load on that circuit (in KW).

The CAR-15 circuit feeds downtown Bellingham. Its load mix is 76 percent commercial and 24 percent residential, and it experiences a winter peak.

Figure M-3: Car-15 Daily Load Curves

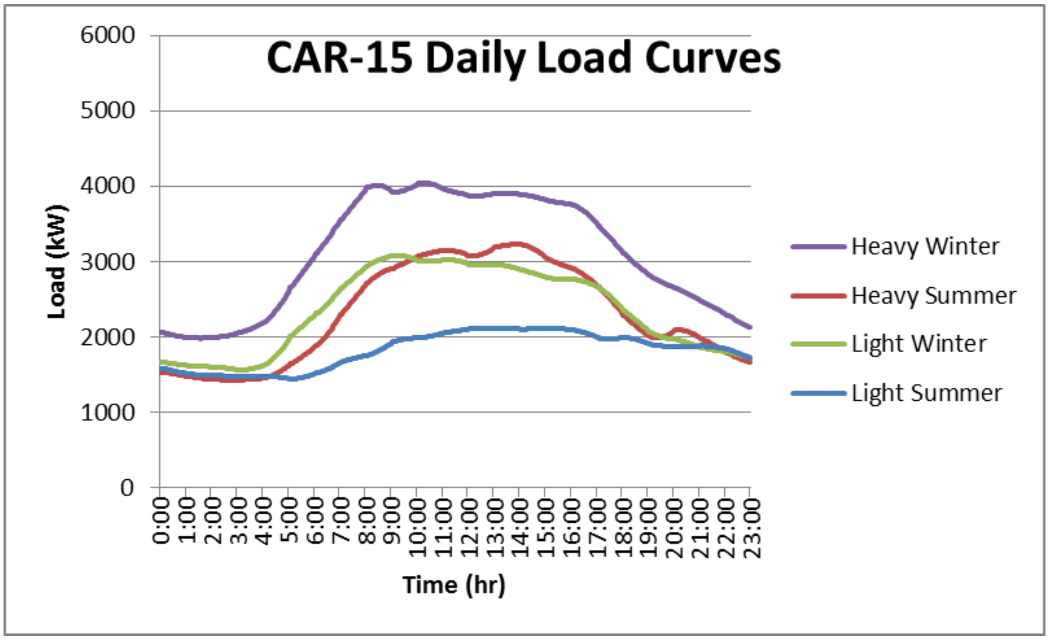
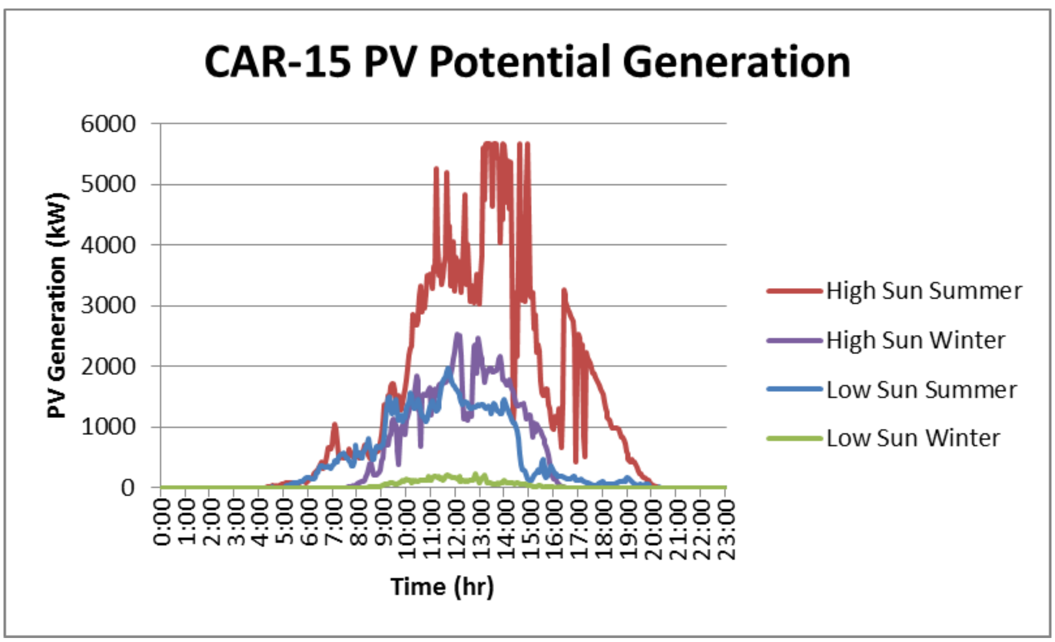


Figure M-4: Car-15 Potential PV Generation



WIN-16 on Bainbridge Island is a small circuit with a 51 percent commercial / 49 percent residential mix. The island does not have natural gas heating, so it experiences a big morning peak in winter.

Figure M-5: WIN-16 Daily Load Curves

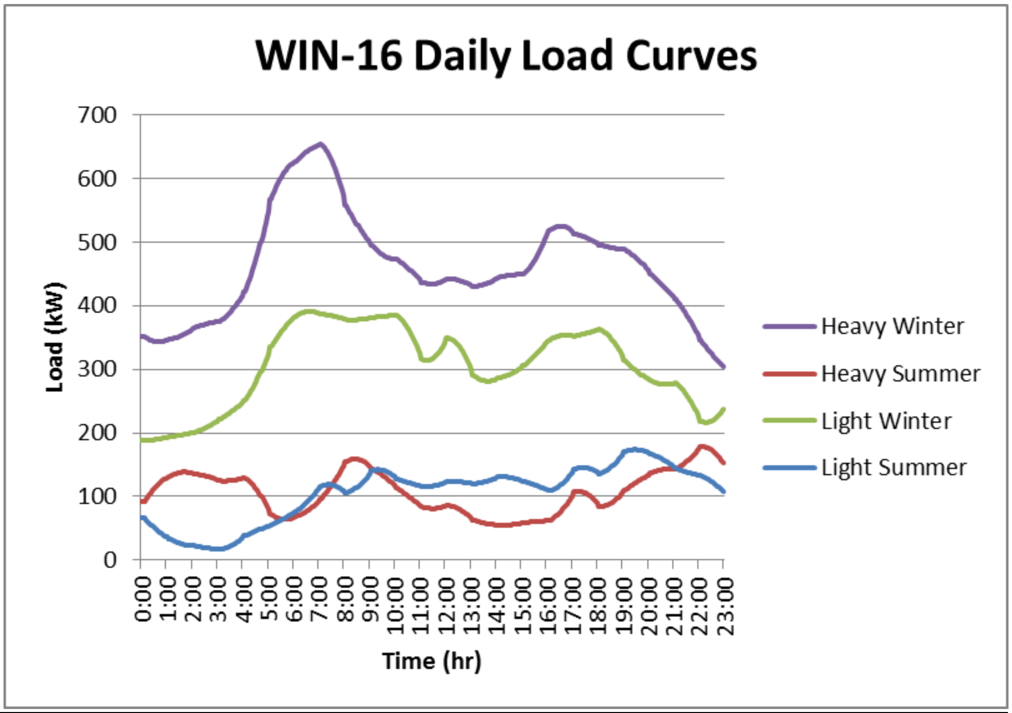
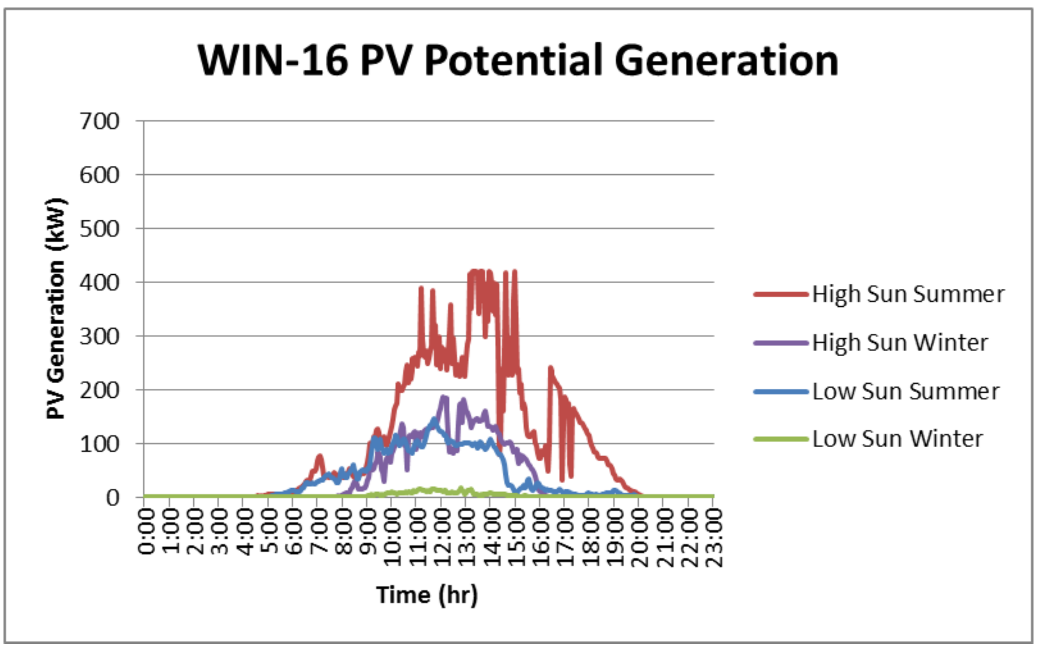


Figure M-6: WIN-16 Potential PV Generation



UHL-21 in Redmond is primarily residential (71 percent), and experiences a winter evening peak. Note that this circuit is 10 times larger than WIN-16.

Figure M-7: UHL-21 Daily Load Curves

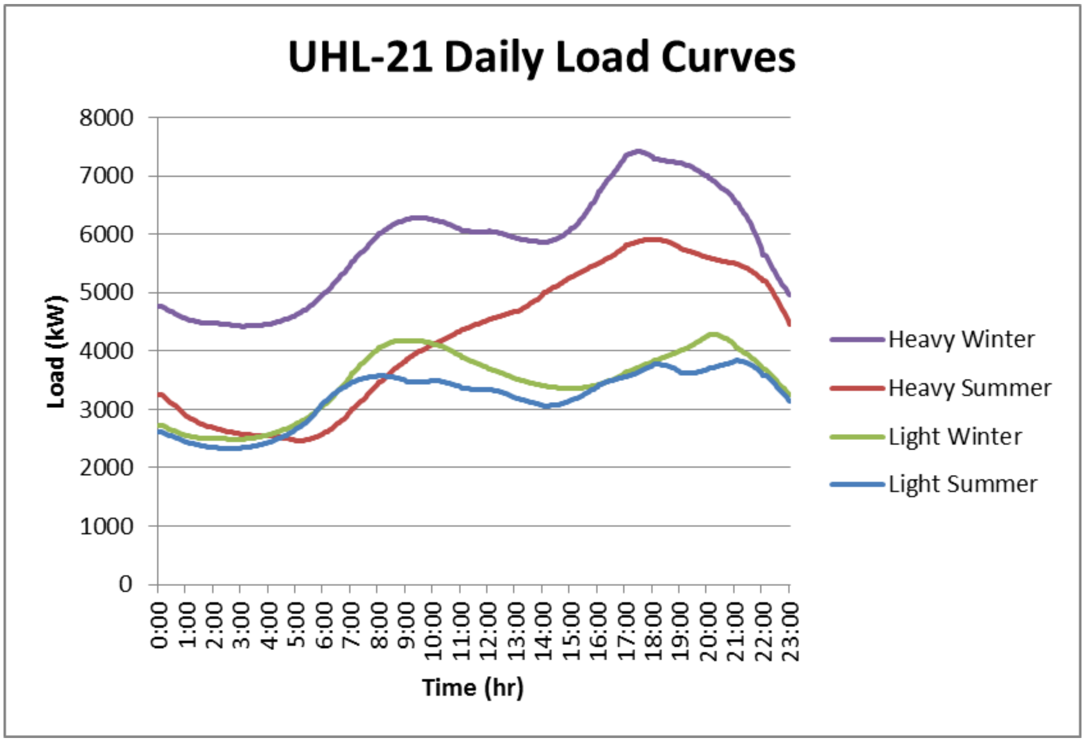
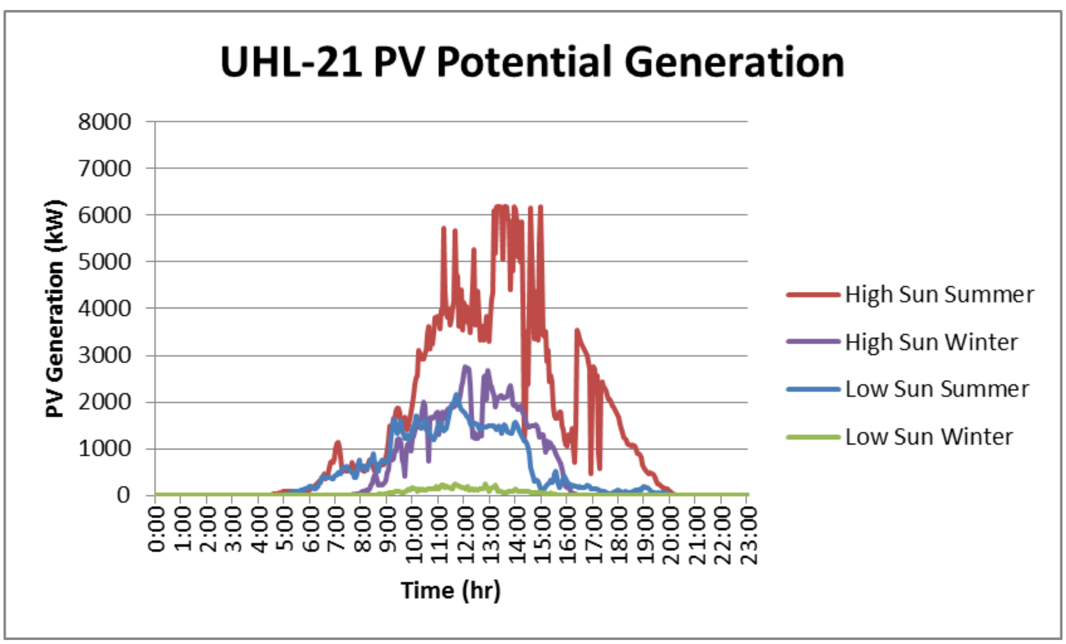


Figure M-8: UHL-21 Potential PV Generation



In Redmond, EVE-17 is an all-commercial circuit. Unlike the other three circuits, EVE-17 produces a summer afternoon peak because of the many offices it feeds. Since this circuit serves only three commercial buildings, and the maximum solar potential generation is 200 kW per building, the maximum solar potential for the entire circuit is only 600 kW.

Figure M-9: EVE-17 Daily Load Curves

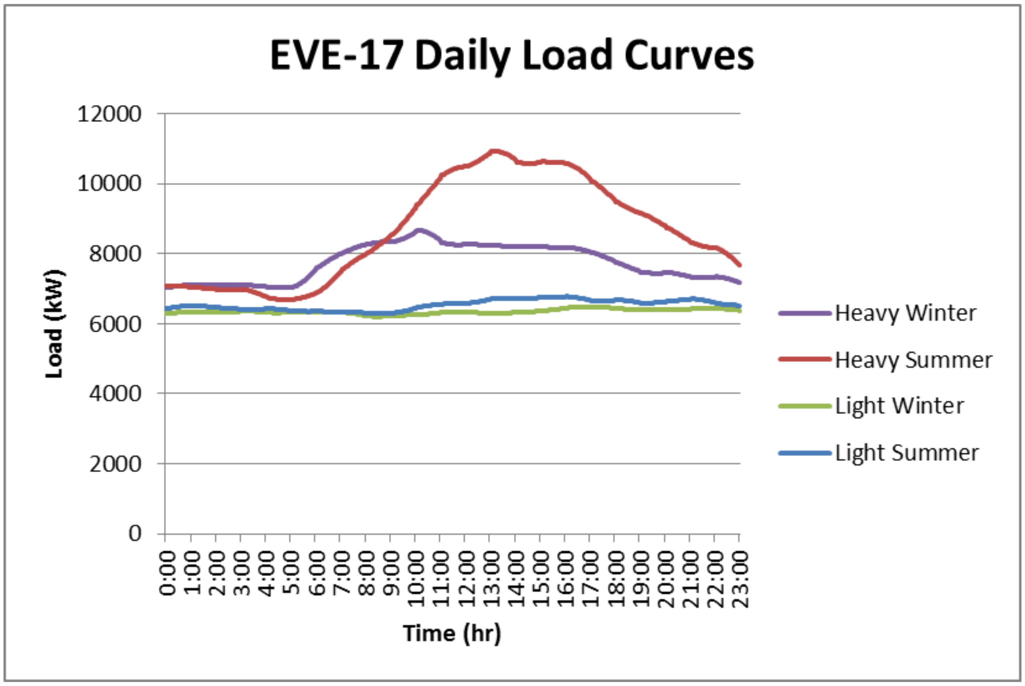
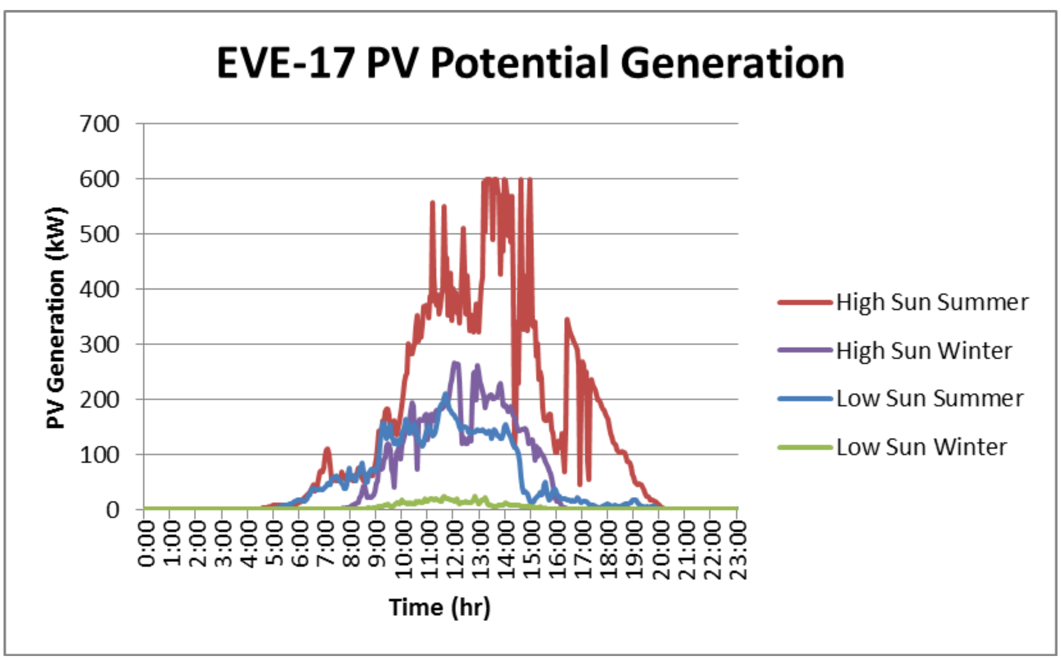


Figure M-10: EVE-17 Potential PV Generation



IMPACT ON DEMAND. The solar PV generation that customers originate is accounted for in the system as a reduction in demand because it reduces the amount of energy that PSE must supply to that circuit from other sources. The more solar PV power that is generated, the more demand is driven down, as illustrated by the red line in the charts below. The less solar power generated, the greater the demand on other PSE resources to supply energy to the circuit, as illustrated by the blue lines. Demand that PSE must fill with system resources will swing between the values shown by the blue and red lines. On CAR-15, for example, on a cloudy day in the summer when customers are using more electricity, PSE will have to provide about 2,000 kW. But on a very sunny day if customers are not using much power, PSE will be purchasing over 2,000 kW from customers.

Figure M-11: CAR-15 Net Demand Range, Summer

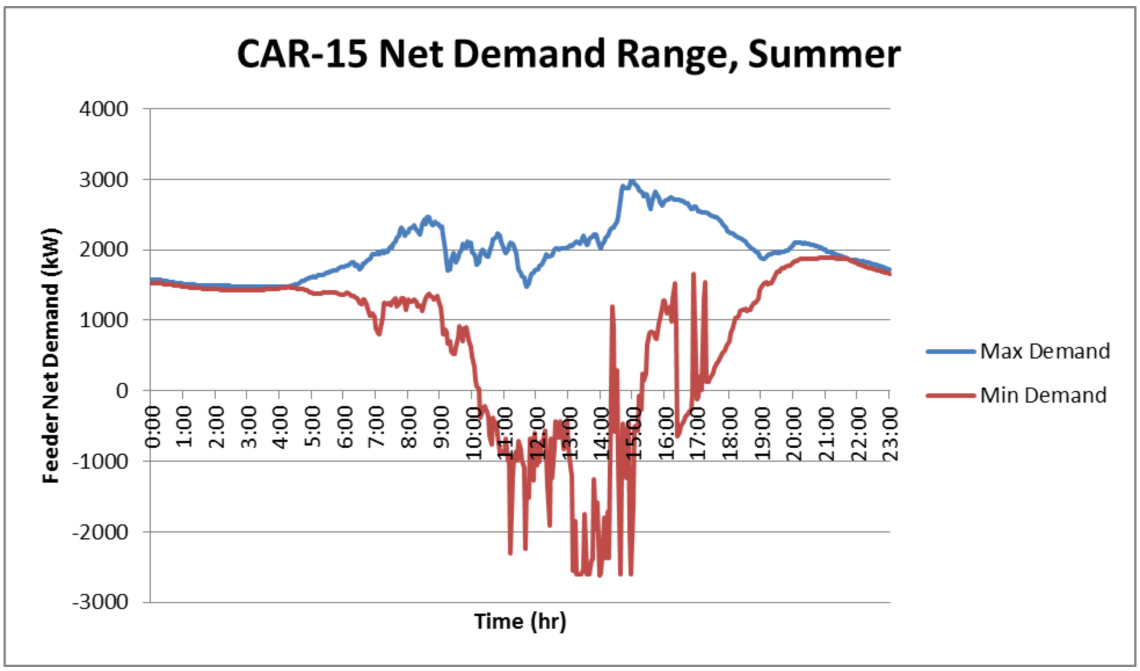


Figure M-12: WIN-16 Net Demand Range, Summer

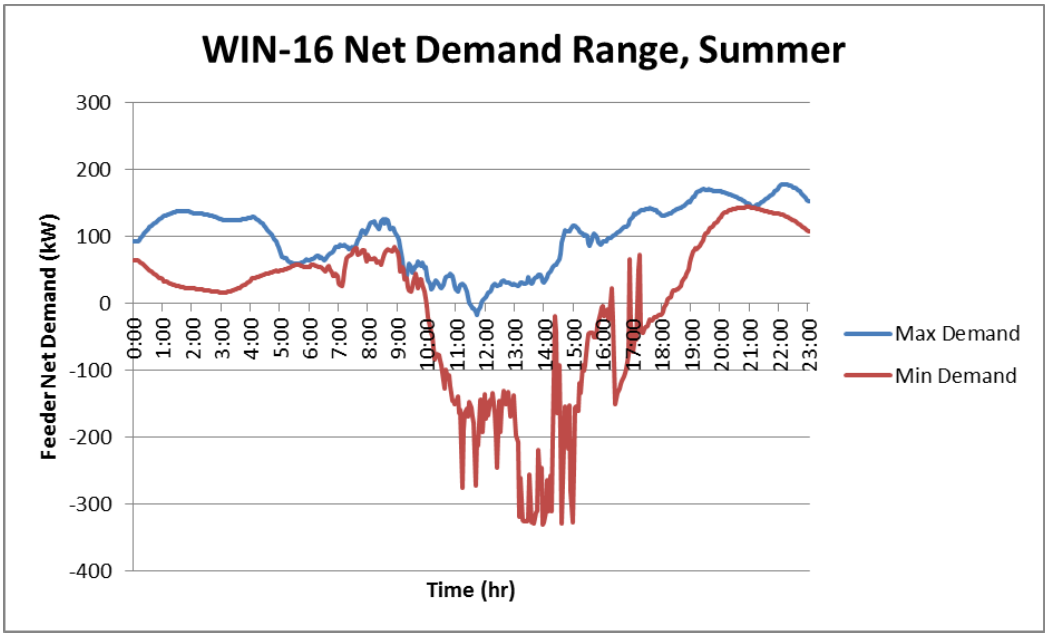


Figure M-13: UHL-21 Net Demand Range, Summer

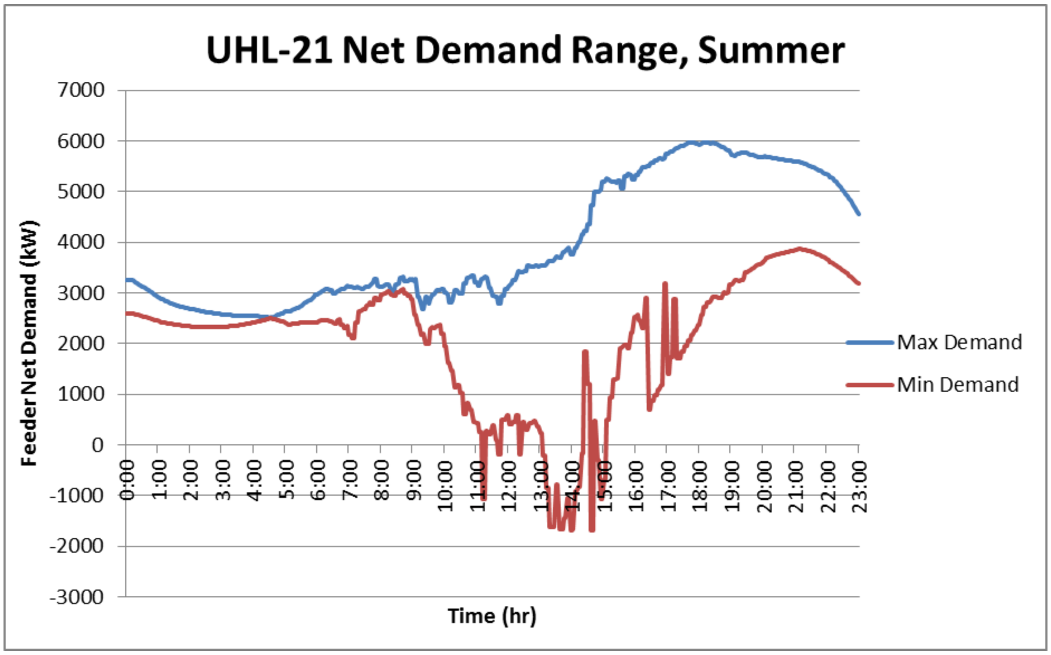
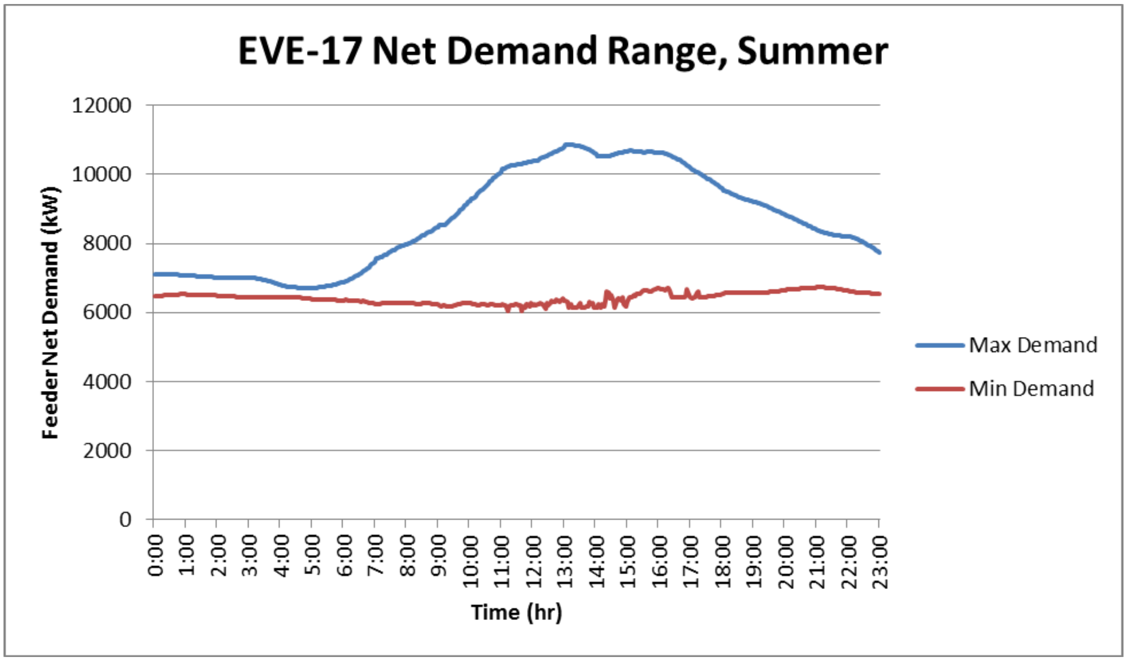


Figure M-14: EVE-17 Net Demand Range, Summer



Findings

Voltage Impacts. Distributed solar PV increases the complexity of managing voltage regulation on circuit feeders due to its intermittent nature.

Power needs to flow to customers at a relatively constant voltage level of 114 to 126 volts per ANSI standard C84.1 (the national standard for utility voltage regulation). Voltage swings outside of this range can wear down utility equipment, degrade customer appliances and create operational issues with sensitive equipment. To keep levels within the acceptable range as customer loads increase and decrease, voltage regulators installed at the substation and/or on the feeder line respond by making adjustments in real time. To prevent unnecessary adjustments, they often operate on a 30 to 40 second delay.

Solar PV adds a layer of complexity by increasing the volatility of voltage changes. When customers' solar panels export power onto the feeder, line voltage surges; when a cloud passes across the sun the PV stops producing and line voltage drops; when the sun comes back out, voltage often spikes again. This variation must now be compensated for in addition to variations in load.

The following charts show the PV generation impact on line voltage for each circuit studied. Note that while 114V is the minimum that can be served to customers, the following charts show the voltage without taking into account the voltage drop across the distribution transformer and customer connection (which can be anywhere from 2 to 6 volts depending on the customer). This means that any instances in the charts where the lowest feeder voltage dips below 120V, there is a possibility that a customer is receiving low voltage (typically verified by taking measurements at the meter following a complaint). Voltage on all circuits remains within the acceptable range, except on UHL-21 which experiences high voltages during periods of heavy solar generation. The voltage at the substation must be set to higher than 120V so that the customers at the end of the line remain within the limit despite the long length of this feeder and the high amount of load it serves.

For CAR-15, Figure M-16 shows that under light summer load conditions, significant levels of PV generation impact both the magnitude of voltage changes and the volatility of those changes on this line. Voltage increases up to 3.4 percent; voltage can also spike down briefly, as shown in Figure M-15.

Figure M-15: CAR-15 Heavy Summer Lowest Feeder Voltage Variation

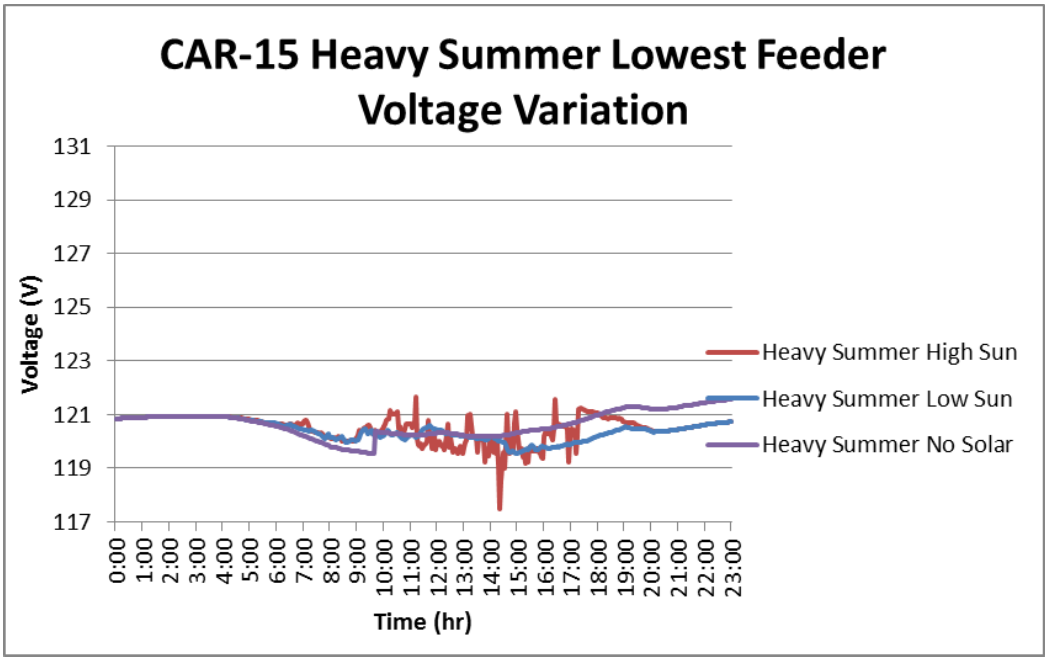
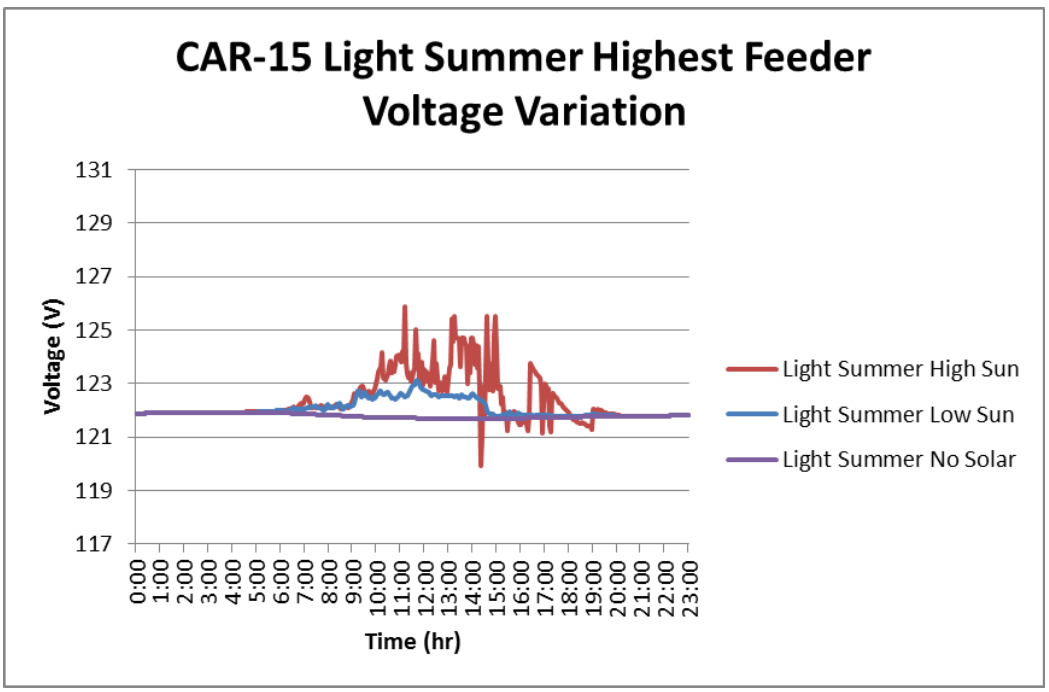


Figure M-16: CAR-15 Light Summer Highest Feeder Voltage Variation



On UHL-21, Figure M-17 shows that distributed solar generation does not help increase the minimum voltage on the circuit during heavy summer loading. Figure M-18 shows that it can cause some customers to receive much higher voltages than allowed during periods of high solar generation.

Figure M-17: UHL-21 Heavy Summer Lowest Feeder Voltage Variation

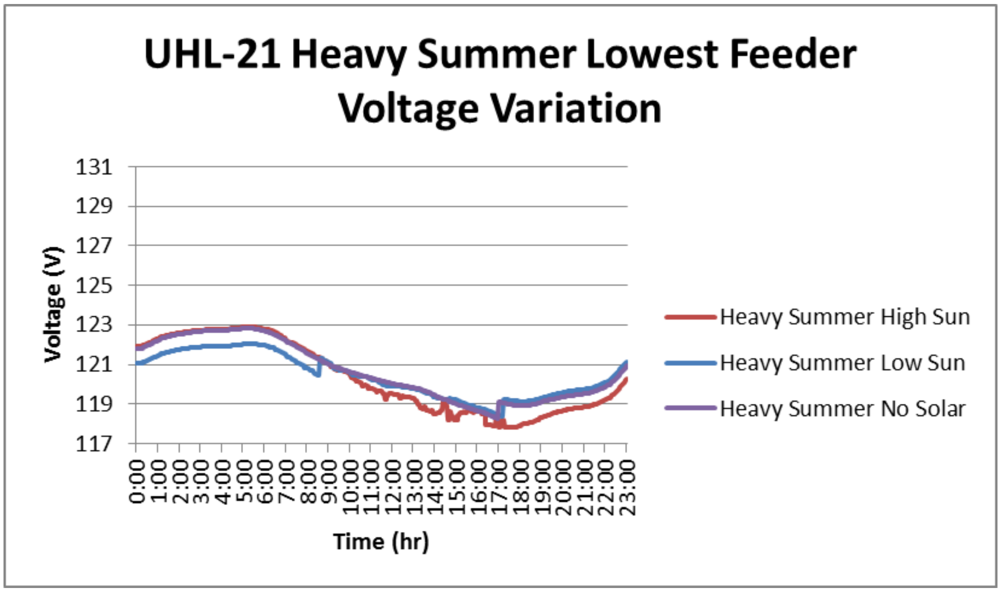
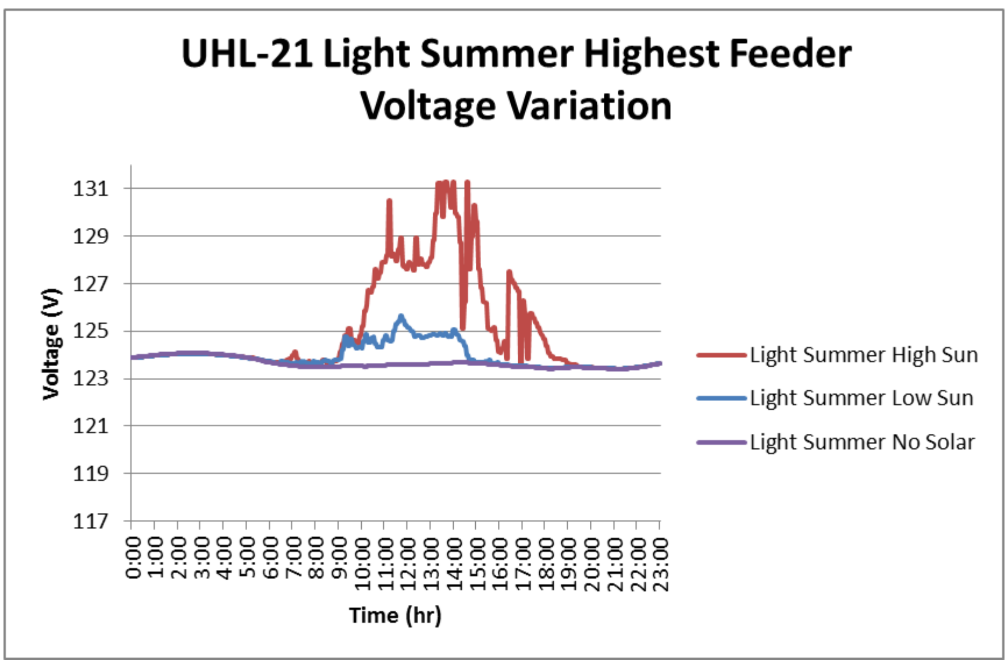
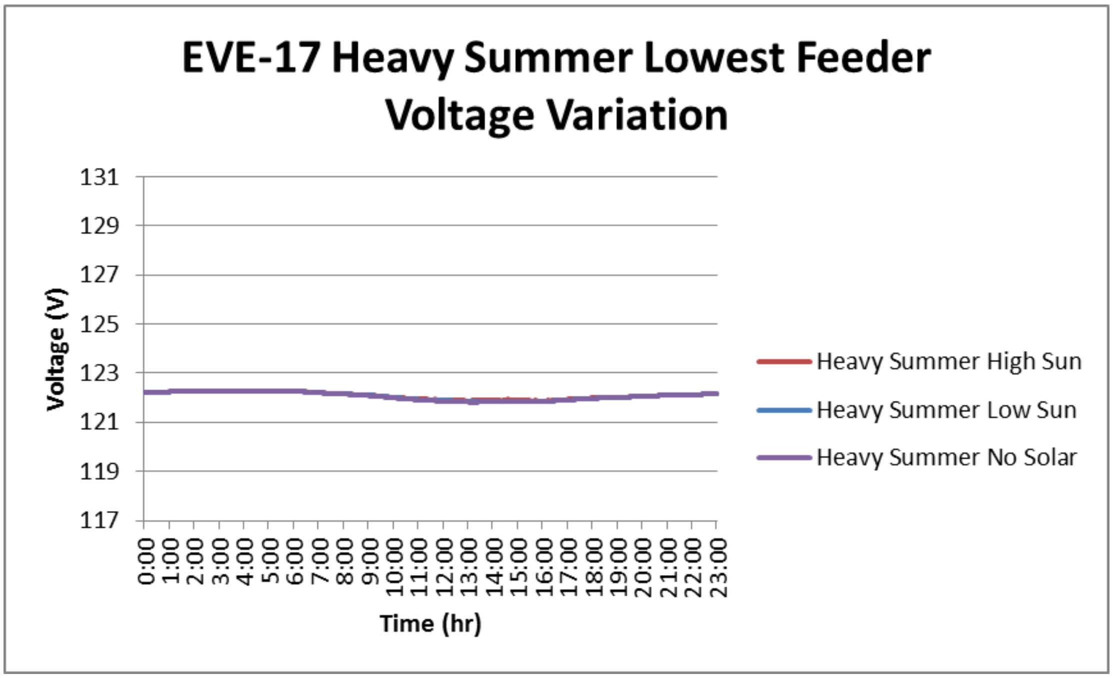


Figure M-18: UHL-21 Light Summer Highest Feeder Voltage Variation



EVE-17 is the circuit that serves only three commercial buildings in Redmond, so it has only 9 percent PV potential penetration. Figure M-19 shows that EVE-17 experiences a voltage increase of only 0.057 percent (unnoticeable on the same scale as the other charts), compared to 3.4 percent in the CAR-15 circuit. The highest feeder voltage was constant because the potential solar penetration was not significant enough to raise the voltage above the substation voltage on any section of the circuit, therefore it is not shown. Similarly, WIN-16 did not have a high enough potential solar generation to noticeably impact circuit voltages; it is also not shown.

Figure M-19: EVE-17 Heavy Summer Lowest Feeder Voltage Variation



Peak Demand. Meeting peak demand is a particularly important responsibility, so we wanted to know if distributed solar PV generation can contribute to meeting that need. In the charts below, the purple line represents the daily demand curve for a circuit in its peak demand season. The space between the purple line and the red line represents the reduction in demand that is produced by solar PV generation on high sun days. Only on EVE-17 does solar PV contribute to meeting peak need.

CAR-15, with 76 percent commercial loads, has a generally flat load once everything is "turned on." Solar generation contributes to meeting need during midday, but does not reduce the peak need in the morning.

Figure M-20: CAR-15 Winter Peak PV Effects

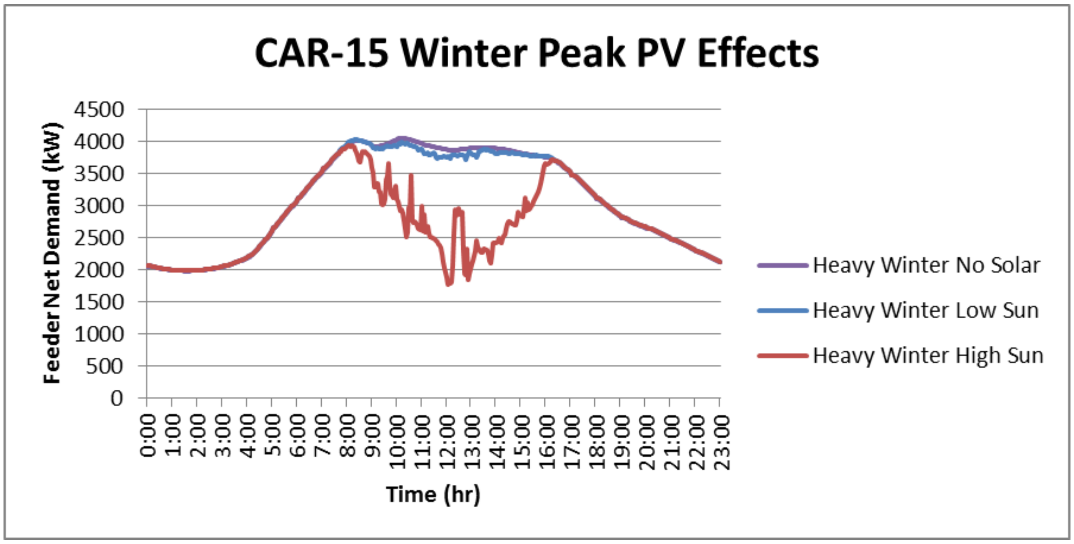


Figure M-21 shows that the winter morning peak on WIN-16 cannot be lowered by additional solar power, although it contributes to meeting need at midday.

Figure M-21: WIN-16 Winter Peak PV Effects

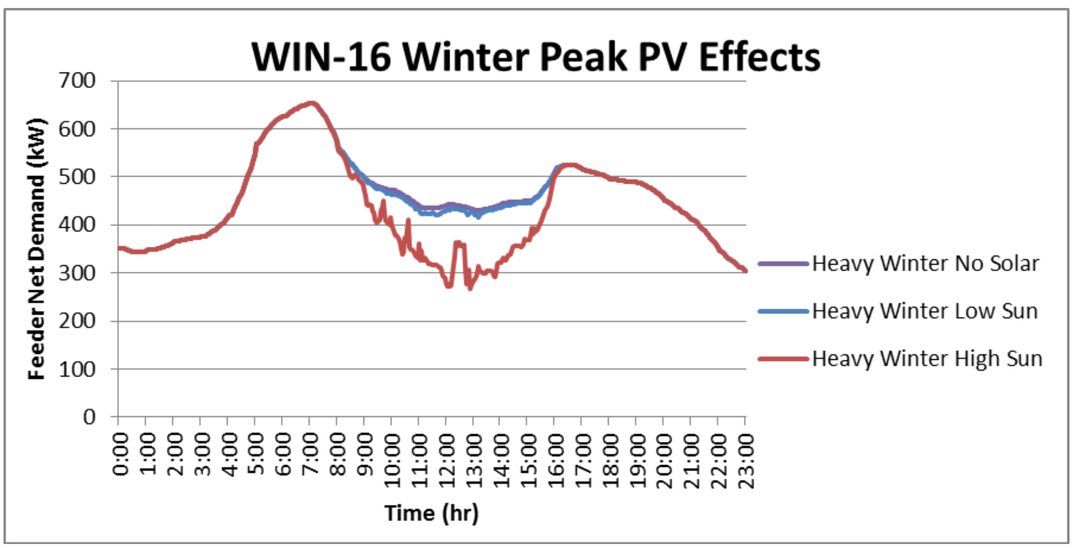


Figure M-22 shows that the evening winter peak on circuit UHL-21 is also not positively affected by solar power; however there are energy savings in mid-day on high sun days.

Figure M-22: UHL-21 Winter Peak PV Effects

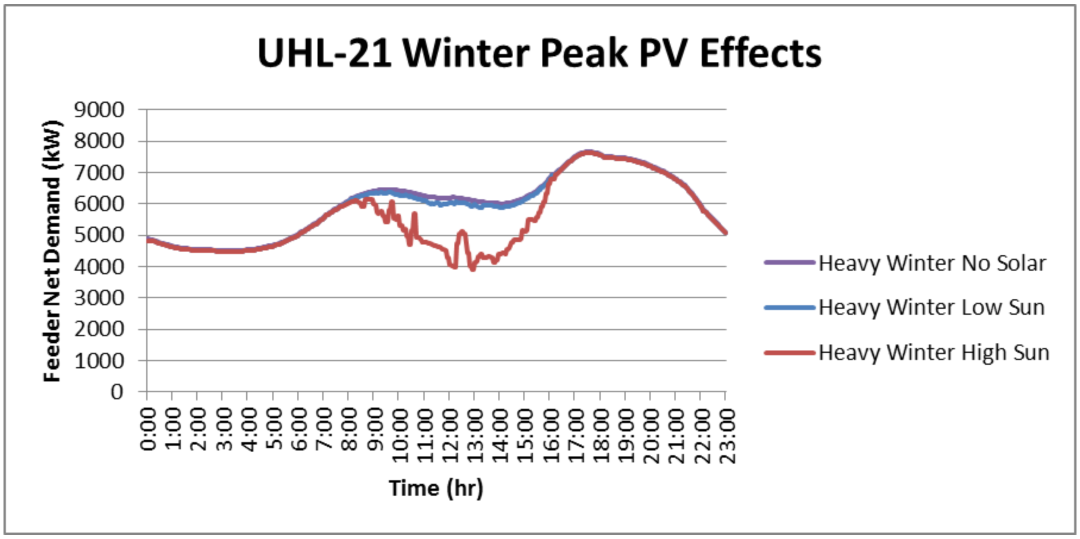
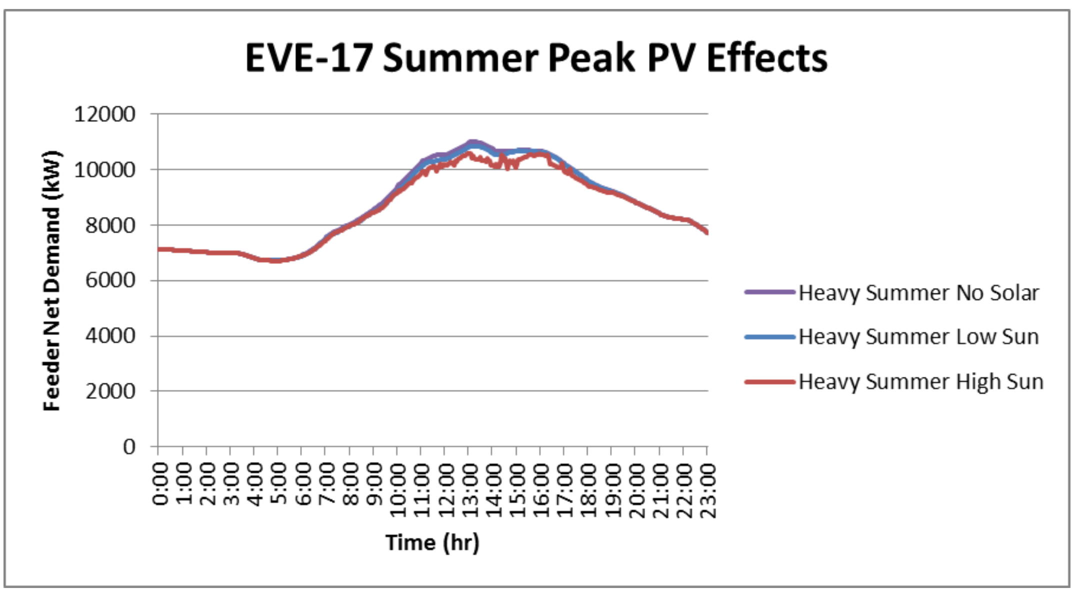


Figure M-23 shows EVE-17, the summer peaking circuit that serves business offices with lots of lighting, computers and air conditioning. On a high sun day, solar power can reduce peak load on this circuit.

Figure M-23: Eve-17 Summer Peak PV Effects



Line Losses. Line losses include all the electric power transmitted on a line but not delivered to the other side. They increase in proportion with the square of the current flowing through the line, so efficiency is higher when less electricity is flowing. When large amounts of solar PV flow back onto the grid, the amount of electricity can be much more than normal, leading to greater line losses.

CAR-15 and UHL-21, below, show significant losses due to the over-supply of PV generation. When compared to the potential PV production in Figures M-4, 6, 8 and 10, these losses range from 25 percent to 30 percent. WIN-16 has losses up to 10 percent. In comparison, the average line loss across PSE's entire transportation and delivery system is approximately 8 percent. While line losses do not cause problems for customers and their appliances, they are an unnecessary waste of energy. Measures to limit line losses include increasing the size of conductors or using smart inverters to limit the amount of energy that goes onto the grid.

Figure M-24: CAR-15 Heavy Summer Line Losses

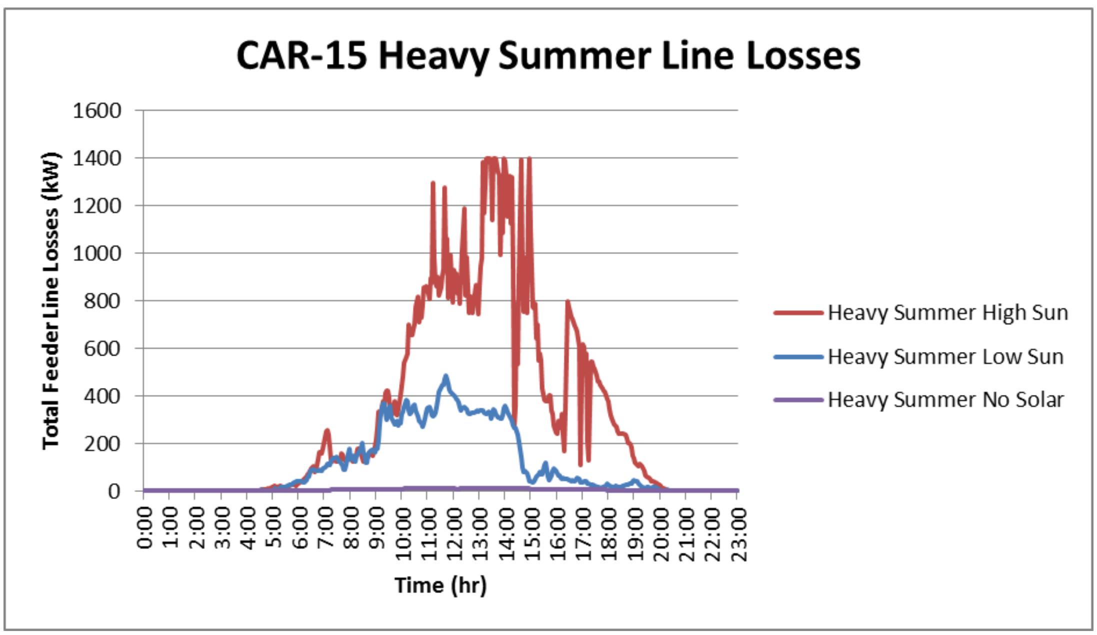


Figure M-25: UHL-21 Heavy Summer Line Losses

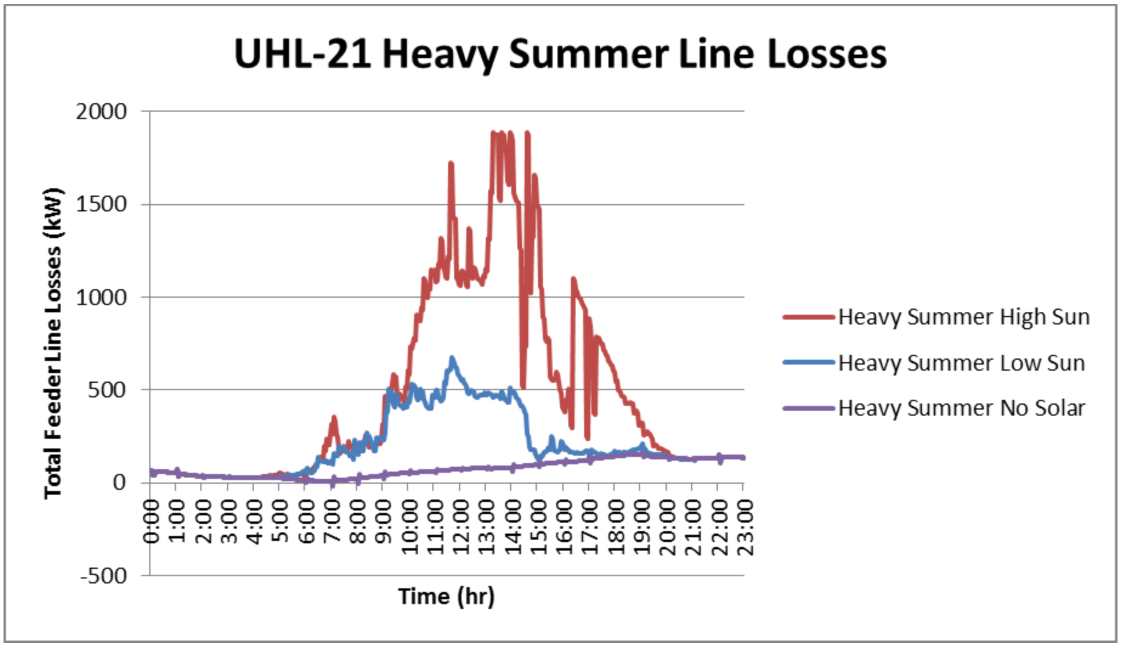
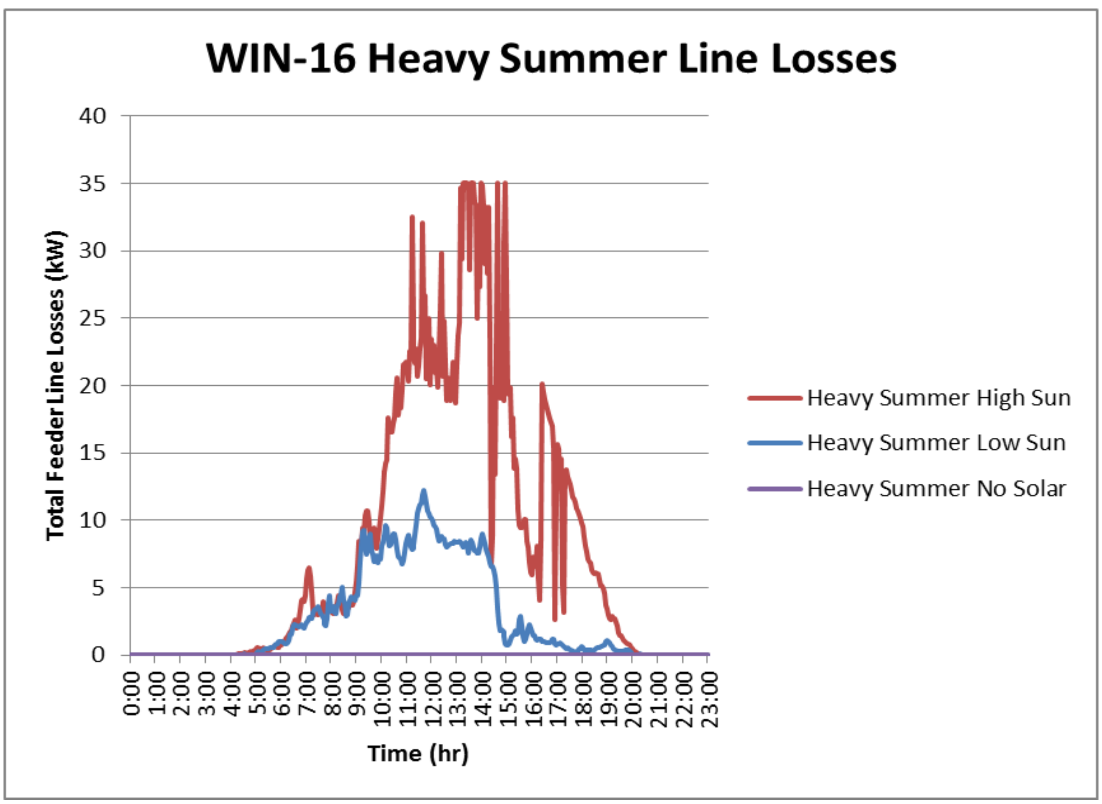
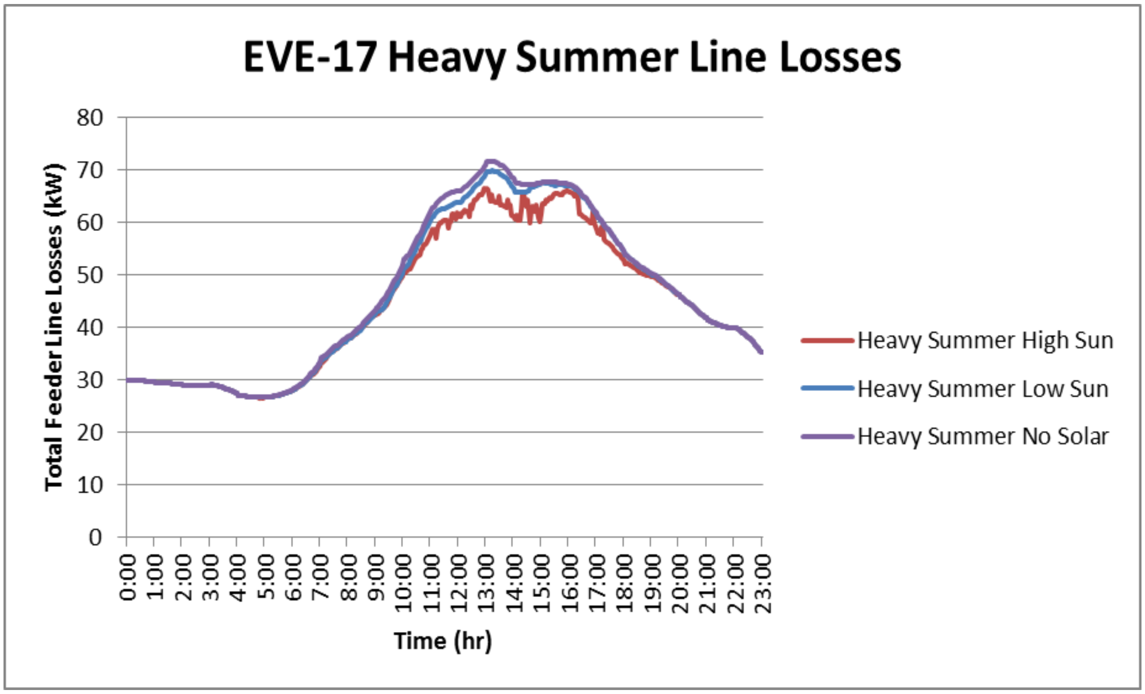


Figure M-26: WIN-16 Heavy Summer Line Losses



EVE-17 provides a very different result: Here, PV can reduce line losses. In this case for the heavy summer load with high sun the daily line loss is reduced by 3.5 percent. This occurred because the solar generation is less than the power consumed by the customer at all times.

Figure M-27: EVE-17 Heavy Summer Line Losses



Summary

As a result of this analysis, the following conclusions were reached. For quick reference, the figures that support each conclusion are referenced in brackets following each bullet.

CUSTOMER VOLTAGE

- Longer feeders are more difficult to keep within voltage limits when serving large numbers of distributed solar customers. [M-18]
- Shorter feeders have more rapidly changing voltages when serving high penetrations of distributed solar customers, but not by enough for customers to be served a voltage outside of allowable limits. [M-16]

LINE LOSSES

- Feeders with load that is distributed across a large area are more likely to see significantly higher line losses with high amounts of distributed solar. [M-24, M-25]
- Solar customers that use more load than they can generate reduce line losses on a circuit. [M-27]

FEEDER DEMAND

- Using realistic assumptions about maximum levels of solar penetration for western Washington, it is possible that some feeders could generate significantly more power than they consume. [M-11, M-12, M-13]
- Demand varies significantly from minute to minute when the volatility of customer load is combined with the volatility of distributed solar generation. [M-11, M-12, M-13]
- Even in the winter, or on cloudy summer days, a significant amount of solar power can be produced by solar customers in western Washington. [M-4, M-6, M-8, M-10]
- Peak demand in winter is generally not reduced by large penetrations of distributed solar generation, because nearly all PSE feeders peak in the winter in either the early morning or evening when there isn't enough sunlight to produce a significant amount of solar power. [M-20, M-21, M-22]
- For feeders that peak in the summer, peak demand is reduced by distributed solar generation. [M-23]

DISTRIBUTED PHOTOVOLTAIC TECHNICAL AND MARKET POTENTIAL

The Cadmus report on this study appears on the following pages.

CADMUS

To: Gurvinder Singh, Tom MacLean; Puget Sound Energy
From: Shawn Shaw, Lakin Garth
RE: PSE IRP Distributed PV Technical and Market Potential Study
Date: March 19, 2015

Introduction

This memorandum outlines the approach used, and key results obtained, in our analysis of Puget Sound Energy's (PSE's) photovoltaic (PV) technical and market potential. The preliminary results presented in this memorandum, unless stated otherwise, apply to the 2016-2035 study period and may not reflect cumulative totals that include PV installations from 2009-2015.

Key Findings

We have analyzed the technical and market potential for PV in PSE's service territory for the 20 year period from 2016-2035. Over this period, we expect PSE's technical potential to be 14,037 MW (nameplate) for rooftop solar PV, based on the feasible roof area available and current projections for array power density, as discussed below. This technical potential reflects the maximum amount of rooftop PV that could be installed in PSE's service territory, regardless of economic or policy considerations. This reflects an upper bound on PV installed capacity and PSE will likely install a much smaller amount of PV, after accounting for market factors.

These factors, which reflect economic, technology acceptance, and policy considerations, are included in the market potential. For PSE's service territory, over the study period, we have calculated a cumulative market potential of 3 MW under our Baseline scenario. Under a Best Case scenario, reflecting a suite of favorable policies, PSE's market potential is 309 MW by 2035. The low market potential for the Baseline scenario is driven by expiration of several important incentives during the study period, including the investment tax credit (ITC), Renewable Energy System Cost Recovery Program (CRP), and the State Sales Tax Exemption. Extending either the ITC or, in particular, the CRP will have a substantial impact on the market and increase PSE's market potential. Should nothing change with regard to current PV policies affecting PSE customers, there will likely be a substantial decline in installation rates, resulting in essentially zero growth in installed capacity from 2016 through 2030. Declining costs of PV will begin to encourage some growth after 2030 but, in the interim, the PV industry in Washington will likely experience substantial decline compared to present levels.

Technical Potential Methods and Results

The technical potential of rooftop PV is a function of available roof area suitable for PV installation and the power density of ever-more efficient PV arrays.

Available Roof Area

We calculated the available roof area based on building square footage, obtained from the Commercial Buildings Energy Consumption Survey (CBECS) and the residential data is PSE's 2010 Residential Appliance Saturation Survey (RASS) data and an assumed number of floors per building type. By dividing the overall square footage of each building category (single family residential, K-12 school, etc.) by the number of floors, we estimated the roof area available for each type of building, as shown in Table 1 (commercial) and Table 2 (residential). The estimated number of floors is an average, based on the number of floors reported by facility owners participating in the survey, rather than archetypal examples of each building type.

Table 1: Available Area by Building Type (Commercial)

Building Type	Building Floor Area (ft^2)	Estimated Floors	Roof Area (ft^2)	Customer Counts
Dry Goods Retail	11,500	1.22	9,426	12,210
Grocery	32,000	1.18	27,119	1,870
Hospital	17,000	1.65	10,303	6,857
Hotel/Motel	17,500	2.74	6,387	1,897
Office	15,500	1.82	8,516	44,542
Other	12,000	1.22	9,836	40,576
Restaurant	3,500	1.27	2,756	5,114
School	53,500	1.15	46,522	2,238
University	56,000	2.57	21,790	779
Warehouse	60,500	1.14	53,070	5,413
Total Commercial	**279,000**	**1.60**	**174,812**	**121,494**

Table 2: Available Roof Area by Building Type (Residential)

Building Type	Building Floor Area (ft2)	Estimated Floors	Roof Area (ft2)	Customer counts
Multi-Family	1,300	2.00	650	207,591
Manufactured	1,570	1.00	1,570	71,778
Single Family	1,921	2.00	961	681,994

Adjusted Available Area

The raw available area cannot be used directly to estimate technical potential because not every roof is suitable for PV. To account for factors such as unsuitable roof orientation or roof space that is not suitable for PV, we made several engineering assumptions. The assumptions used in our analysis are summarized below, in Table 3. While most of these assumptions are the same as those used in our 2008 analysis, we updated the analysis to include a reduction in available roof area due to Washington's recent adoption of the 2012 International Fire Code (IFC) Article 605.11.3, which requires minimum roof area be maintained for safe access by emergency personnel. The addendum was effective on April 1st, 2014, and requires that PV arrays "shall be located no higher than 18 inches (457 mm) below the ridge in order to allow for fire department rooftop operations". Though this is less stringent than similar codes adopted in California and other jurisdictions, it nevertheless limits the available roof area for installing PV modules.[1]

Table 3: Adjusted Available Area Assumptions and Inputs

Assumption	Value in Previous Analysis
Roof Pitch (Manufactured/Single Family)	4/12 pitch, equal to 18.4°
Roof Pitch (Commercial/Multifamily)	Flat roof, 0° pitch
Usable Roof Orientation	25% each for East, South, and West facing roofs, for a total of 75% for pitched roofs and 100% for flat roofs. Only 50% of pitched roof area is correctly oriented, however, to account for the north side of south-facing roofs.
Roof Area Available due to Obstructions	70%-Multifamily, 85%-Single-family/manufactured, 80%-commercial
Roof Area Unsuitable due to Shading/Technical Feasibility Restrictions	50%-Residential, 15%-commercial
Roof Area Unavailable due to adoption of IFC 605.11.3	4-6% (residential only, varies by building type)
Overall Roof Area Available	**16%-Single-family, 16.2%-Manufactured, 32.9%-Multifamily, 65%-Commercial**

Power Density

After determining the available area for PV installation, it is important to then understand how much power can be generated on a per unit area basis. With constant improvements in PV cell and module efficiency, power densities are likely to increase by 20%, or more, over the study period.

Table 4: Power Density Assumptions and Inputs

Assumption/Input	Value in Previous Analysis
Module Power Density	15.5 peak Watts (Wp)/ft^2, based on the five most commonly installed PV modules in Washington
Array Inactive Area	25% of array space devoted to wiring, inter-module spacing, and similar non-collecting surfaces
Annual Increase in Module Efficiency	2.1% per year (equivalent to roughly 0.3 points increase in module efficiency per year) based on US DOE module efficiency projections.
Overall Power Density	**12.9 Wp/ft^2 in 2016, increasing by 2.1% per year**

[1] Washington State Department of Enterprise Services, State Building Code (https://fortress.wa.gov/ga/apps/sbcc/Page.aspx?nid=14)

Electricity Generation

PV direct current (DC) capacity is a product of the available roof area and the power density. We converted the PV capacity (kW) into annualized electricity (kWh) generation. In order to estimate annual energy savings PSE provided a value of 1,000 kWh per kW_{DC} installed, based on historical performance of net-metered PV systems in PSE territory. Though this is method would poorly reflect any single PV project's expected annual generation, it is a reasonable approximation of the mix of PV system designs currently operating in PSE's territory.

Technical Potential Results

Based on the analysis described in the previous sections, we estimate that PSE's total technical potential for PV installed from 2016-2035 is 14,037 MW. The majority (84%) of this technical potential is in the commercial sector, with 16% from the residential sector. If installed, this amount of PV would generate approximately 14,037 GWh annually. The predominance of the potential in the commercial sector is driven by the substantially larger available roof area in the commercial sector and the greater portion of roof area suitable for the installation of solar PV systems.

Market Potential

After calculating the technical potential, which provides a likely upper bound on PV capacity growth, we considered relevant market factors to determine likely PV growth for PSE planning purposes. In order to assess market potential, we first examined the customer economics of PV in PSE's service territory, in terms of simple payback. We then used this metric to subsequently calculate market potential for several policy-based scenarios.

Customer Payback

Simple payback is a metric commonly used in the sale of energy efficiency and renewable energy technologies. Though it is a simplistic calculation, it is intuitively easy for customers to understand and is a key factor in their financial decision-making process. For this analysis, we have calculated simple payback using Equation 1.

Equation 1: Annualized Simple Payback

$$ASP = \frac{Net\ Costs\ (after\ incentives)}{Annual\ Energy\ Savings + CRP\ Payments}$$

Though Equation 1 is conceptually simple, the mix of incentives and cost projections added complexity to the calculations. For purposes of this analysis, we used the assumptions described in Table 5 (residential costs), Table 6 (residential revenue), Table 7 (commercial costs), and Table 8 (commercial revenue).

Table 5: Residential PV Net Cost Assumptions

Assumption	Value	Source
System Cost	$4.7/W_{DC}$ in 2013	Tracking the Sun VII Report, Lawrence Berkley National Laboratory (2014)
Annual Cost Reduction	11%-3%	See discussion of cost assumptions, below
System Capacity	5kW	Assumption
Investment Tax Credit (ITC) ends 12/31/2016	30%	Database of State Incentives for Renewable Energy (DSIRE)
State Sales Tax Exemption	6.5%	Database of State Incentives for Renewable Energy (DSIRE)

Table 6: Residential PV Revenue Assumptions

Assumption	Value	Source
Net Metering Rate	$0.0853/kWh	2012
Utility Rate Escalation	3%	EIA Electric Power Annual (rate change 2012-2013)
Annual Generation	1,000 kWh/kW_{DC}	Provided by PSE staff
CRP Incentive Rate[2]	$0.39	Average of incentive claim requests, provided by Washington State University via email[3]

Table 7: Commercial PV Net Cost Assumptions

Assumption	Value	Source
System Cost	$4.30/W_{DC}$ in 2013	Tracking the Sun VII Report, Lawrence Berkley National Laboratory (2014)
Annual Cost Reduction	11%-3%	See discussion of cost assumptions, below
System Capacity	100kW	Assumption
Investment Tax Credit (ITC)	30%	Database of State Incentives for Renewable Energy (DSIRE)
Investment Tax Credit (ITC) after 12/31/2016	10%	Database of State Incentives for Renewable Energy (DSIRE)
State Sales Tax Exemption	6.5%[4]	Database of State Incentives for Renewable Energy (DSIRE)

[2] Note that our analysis capped payments at $5,000 per year, regardless of incentive rate

[3] Note that this is a statewide figure and is assumed to be applicable to PSE customers

[4] Note that this exemption also includes local sales taxes. To be conservative, we have only included the baseline state sales tax rate in this analysis but, anecdotally, expect that this number may be closer to 10% when all local taxes are included. A survey of local sales tax rates was not included in this study.

Table 8: Commercial PV Revenue Assumptions

Assumption	Value	Source
Net Metering Rate	\$0.0768/kWh	2012
Utility Rate Escalation	2.5%	EIA Electric Power Annual (rate change 2012-2013)
Annual Generation	1,000 kWh/kW_{DC}	Provided by PSE staff
CRP Incentive Rate	\$0.39	Average of incentive claim requests, provided by Washington State University via email. Note that the CRP is capped at \$5,000 per year.

We did not include operations and maintenance (O&M) costs in the simple payback calculation because these costs are rarely (and certainly not consistently) reflected in the PV system sales process. As the market penetration model uses simple payback as a means of predicting customer purchase decisions and O&M costs occur after the purchase is made, we deliberately excluded these costs from the analysis.

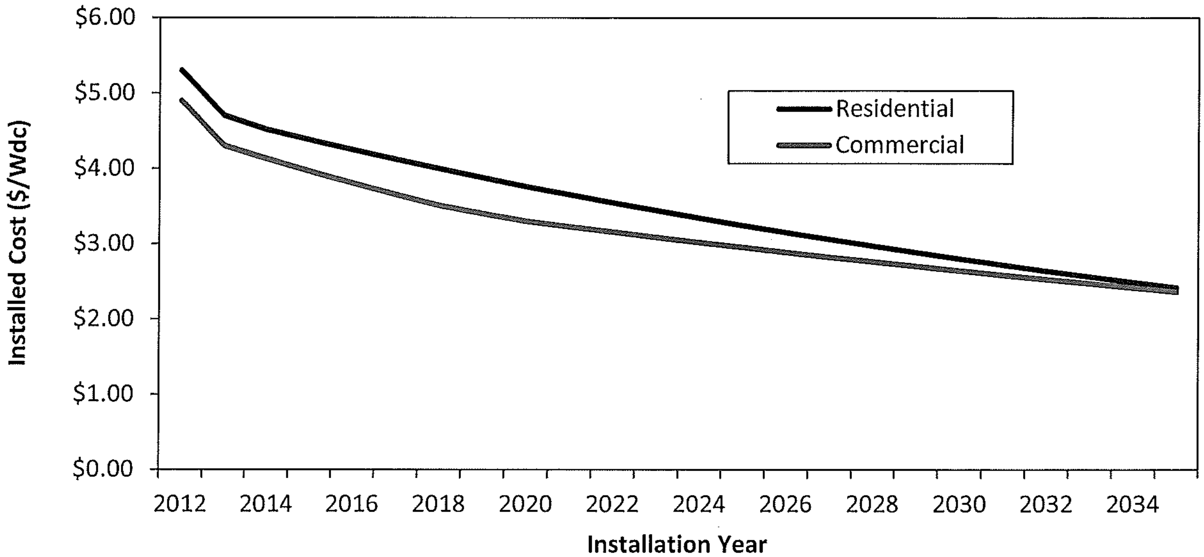
For purposes of this analysis, we assumed that the net system cost, after applying relevant incentives, was paid on a cash basis and, therefore, have not included cost of capital in the simple payback calculation.

Installed Costs

We compiled assumptions for residential and commercial installed cost (\$/W) from several sources to arrive at a reasonable projection through the study period. We used the Tracking the Sun VII 2014 Report[5] for the starting point, with the 2013 installed costs \$4.90/W and \$4.3/W respectively for residential and commercial installations. The IREC's 2012 and 2013 Updates & Trends Annual Reports[6] gave supporting evidence of the trends in the past years. We looked to the SunShot Vision Study[7] – February 2012 and the U.S. Energy Information Administration's (EIA's) Annual Energy Outlook 2014[8] reports to project future price trends. The SunShot report compared the Sunshot goal (\$1.50/W for residential and \$1.25/W for commercial in 2020) to a reference price of what would occur if SunShot initiatives were not followed. These prices were \$3.78/W and \$3.36/W, respectively. We used the reference prices for the 2020 installed cost as a benchmark, varying the annual price decrease to meet these benchmark price points in 2020. From 2021-2035, we assumed a decrease of 2.9% (residential) and 2.2% (commercial) for a final installed cost of \$2.42/W for residential and \$2.36/W for commercial installations in 2035 as shown in Figure 1 . Given that the Sunshot report reference cases are a conservative estimate of future pricing, it is likely that installed costs will fall faster than predicted, which would result in a correspondingly higher market potential.

[5] Tracking the Sun VII 2014: http://emp.lbl.gov/sites/all/files/lbnl-6808e_0.pdf
[6] IREC's 2012 and 2013 Updates & Trends Annual Reports: http://www.irecusa.org/publications/
[7] SunShot Vision Study – February 2012: http://www1.eere.energy.gov/solar/pdfs/47927.pdf
[8] U.S. Energy Information Administration's (EIA's) Annual Energy Outlook 2014 (AEO2014): http://www.eia.gov/forecasts/aeo/

Figure 1: Projected Installed Cost of PV Through 2035[9]



Market Penetration Rates

Predicting what portion of technically feasible sites will actually install PV systems during the study period is a complex process that is driven by many policy, economic, and technical factors beyond PSE's direct control. For this analysis, we have used a variant on the Bass Diffusion Model, used in similar market potential studies in other states[10]. This model estimates market penetration, as a percent, as a function of customer payback. Prior to being applied to solar PV, this approach has been applied in many energy efficiency studies and it provides a convenient method for modeling a variety of policy and market scenarios, as most of these scenarios have an influence on the simple payback and, as a result, the market penetration calculation. The curve used in this analysis is shown in Equation 2.

Equation 2: PV Market Penetration Model

$$MP = e^{-0.3*ASP}$$

Where MP is Market Penetration (%) and ASP is Annualized Simple Payback (the time, in years, it takes for the energy savings from the PV project to completely offset the undiscounted installation cost). For this analysis, we calculated ASP from the customer perspective, including all relevant incentives.

As with any model, it is always useful to check predictions against historical data to provide confidence in the model's ability to predict future outcomes. In this case, PSE has both annual technical potential and installed capacity (MW) data for 2009-2013. Using this historical data, and our projections of customer payback in these past years, we calculated a retrospective market penetration rate and compared it to the results of Equation 2. While both curves are exponential in nature, the historical

[9] The projected costs are expressed in nominal dollars per Watt.
[10] Distributed Renewable Energy Operating Impacts and Valuations Study, R.W. Beck 2009

data[11] indicates a much steeper increase in market penetration as payback time decreases, with a somewhat lower likelihood to install PV when simple payback exceeds 7 years, as shown in Figure 2. The reason for the differences between the modeled and historical market penetration rates is not entirely clear from the data available. One possible cause is that Equation 2 aggregates a wide variety of customer preferences- such as environmental awareness, distribution of market actor types (e.g., early adopter), and sensitivity to simple payback time-into a single multiplier (-0.3) that may not accurately represent the Washington market. As a result, we used a modified version of Equation 2 to calculate market potential for this study, based on the historical market penetration rates seen over the past four years in PSE's service territory (Equation 3). While this adjusted model is very similar to Equation 2 at long payback periods, the model presented in Equation 3 is more conservative for shorter payback periods and is likely a better fit for predicting long-term market potential in Washington.

As a final note, due to the small population of commercial projects represented in the historical data, we have applied the same market penetration rates to both commercial and residential installations. In reality, these two market segments make purchasing decisions differently and may be better represented with two different market penetration curves. However, there is not sufficient data to generate a market penetration curve for commercial installations at this time.

Equation 3: Adjusted Market Penetration Rate Based on Historical Data

$$MP_{adj} = 0.786e^{-0.425*ASP}$$

[11] Historical data was obtained from net-metering application data presented by Jake Wade in a January 2014 PowerPoint presentation. The installed capacity was given for the years 2009-2013, with assumptions applied as to the percentage of residential PV.

Figure 2: Historical and Modeled Market Penetration (2009-2013)

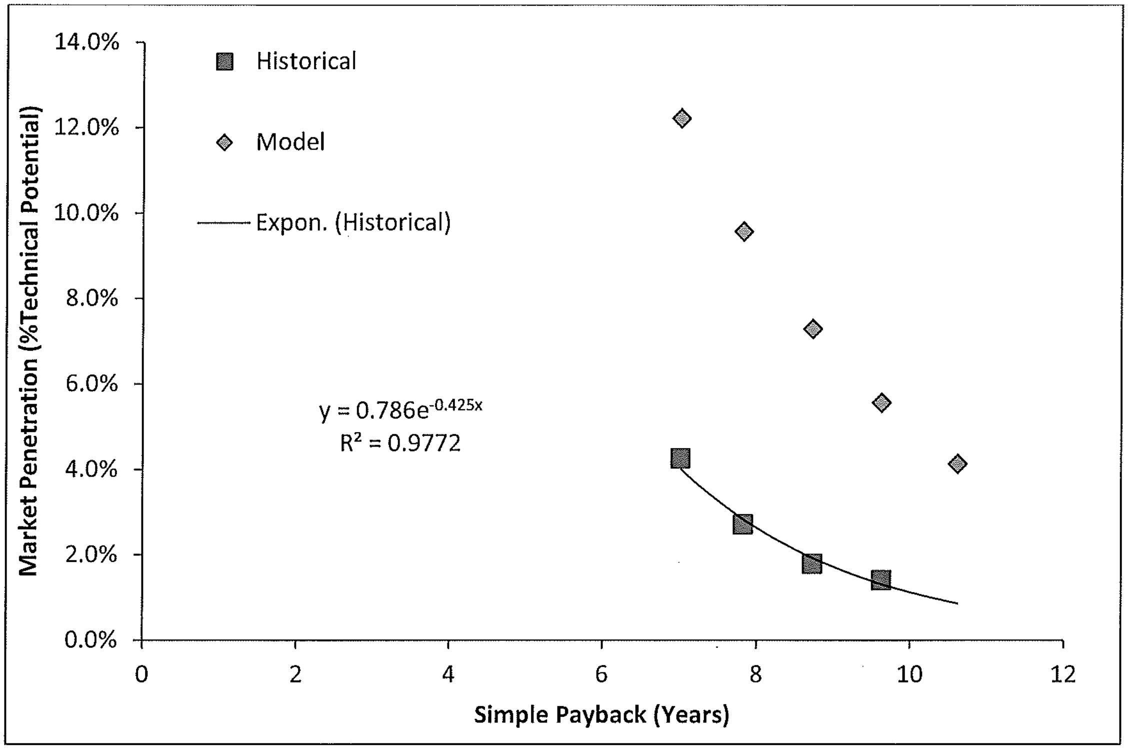
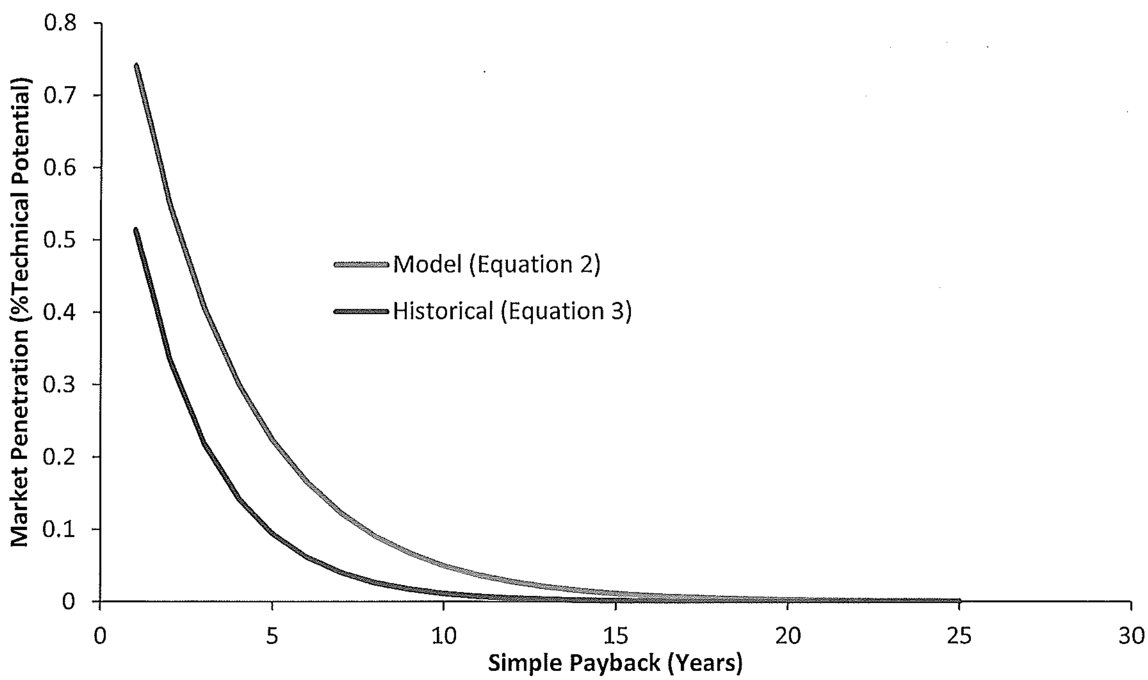


Figure 3: Impact of Model Selection on Market Penetration Rates



Scenario Analysis

The future of the PV market is heavily influenced by policy and incentive decisions. In order to model the influence of these policy changes on PSE's PV market potential, we have developed a series of scenarios reflecting the impact of policy changes on customer payback and, by extension, market potential. These scenarios used the historically based model pictured in Figure 2. The scenarios are summarized below.

Baseline Scenario

In the Baseline Scenario we assume that all existing policies and incentives remain in effect, as currently written, with no changes. This includes several key policies:

- Investment Tax Credit (ITC): The ITC provides a 30% tax credit for PV, expiring on 12/31/2016 for residential but reduced to 10% for commercial
- State Sales Tax Exemption: Solar PV equipment is currently exempt from a 6.5% Washington State Sales Tax. This benefit expires on 6/30/2018.
- Renewable Energy System Cost Recovery Program (CRP): The CRP provides a variable production-based incentive of up to $5,000 per year for PV systems. The incentive level ranges from $0.15/kWh to $0.54/kWh, depending on customer eligibility for a variety of incentive adders (e.g., for using equipment manufactured in Washington). This incentive is set to expire on 6/30/2020.
- Net Metering: PSE is limited to meet 0.5% of peak 1996 loads, or 22.3 MW from net-metered systems up to 100kW.

Extended ITC Scenario

In this scenario, we assume all incentives and policies are the same as the base scenario, except that the ITC is extended through the end of the study period at its current rate of 30%.

Extended CRP Scenario

In this scenario, we assume all incentives and policies are the same as the base scenario, except for the CRP is maintained at the current incentive level through the end of the study period, rather than expiring in 2020.

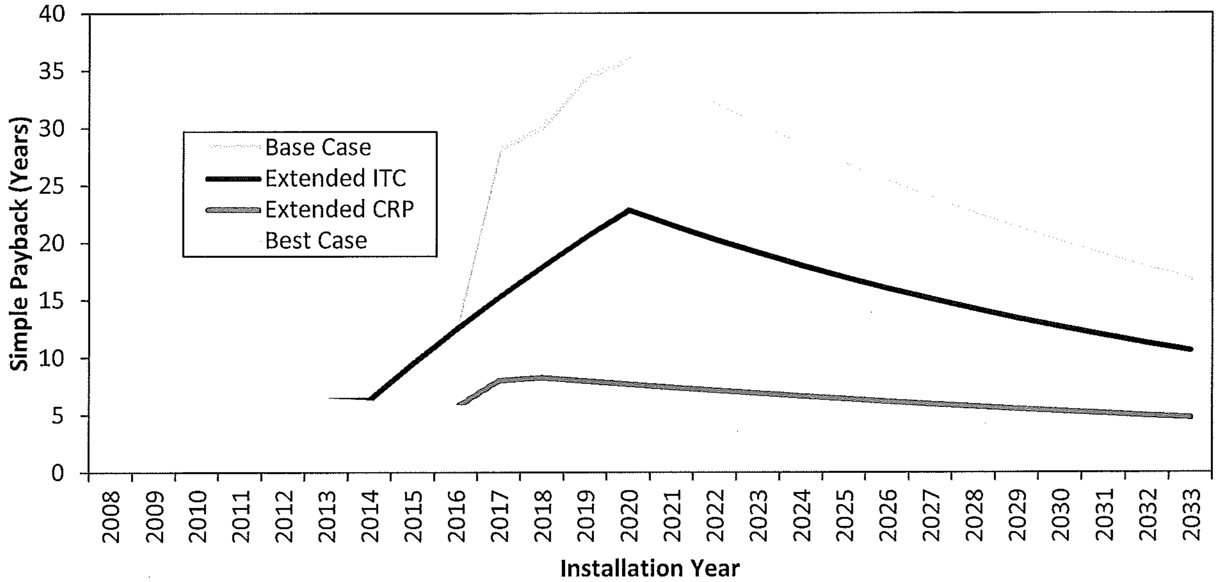
Best Case Scenario

The Best Case Scenario reflects the most favorable policy options of the other scenarios. This case includes the continuation of the CRP, and ITC (at 30%) as well as the State Sales Tax Exemption.

Market Potential Results

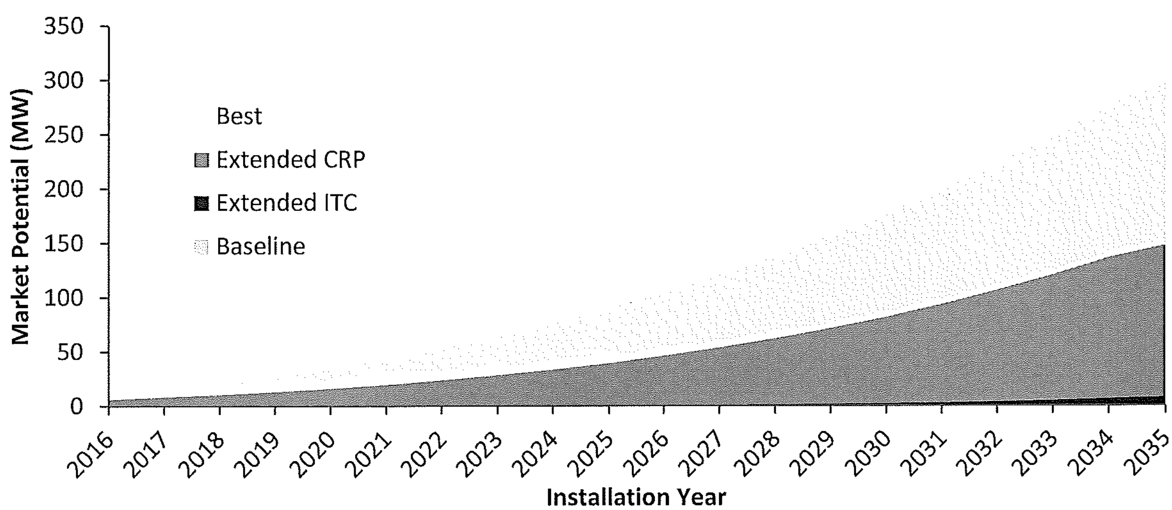
Unsurprisingly, the market potential for PV is heavily influenced by the scenarios described above. We have shown the impact of these scenario choices on expected customer payback (residential) in Figure 4. The expiration of several key incentives over the next few years, shown in the Baseline Scenario, will have a substantial impact on customer payback. For example a residential customer purchasing a PV system in 2014 might expect a simple payback of approximately 6 years, while a customer purchasing a PV system in 2020-after the expiration of the ITC and CRP incentives-could expect a simple payback of 36 years, despite falling costs of PV over the study period.

Figure 4: Residential PV Simple Payback Projections under Four Policy Scenarios



The high payback periods indicated will have a substantial impact on market penetration rates, with installations essentially coming to a halt beginning in 2017, as customers are faced with the declining value of the CRP and the expiration of the ITC simultaneously. As shown in Figure 5, PV market potential is essentially flat, with little growth beginning in 2016, under both the Baseline and Extended ITC scenarios. Though extending the ITC will provide a substantial benefit to the growth of PV compared with the Baseline scenario, by far the largest driver of customer economics (and market potential) is the CRP incentive. Extending the CRP incentive, even in a reduced form, is a key driver to further growth of the Washington PV industry.

Figure 5: Cumulative Residential PV Market Potential by Scenario



We have summarized the market potential results in Table 9. As discussed above, extending the CRP provides a substantial increase in the market potential, more than a five-fold increase over a scenario that extends the ITC but allows the CRP to expire as-scheduled. Under the Baseline scenario, total PV capacity installed during the study period will add another 2 MW to PSE's total PV capacity. For comparison, total installed capacity as of the end of 2013 was 10.6 MW, so capacity added during the 20 year study period would likely equal approximately one fifth of the capacity added over the past 5 years. Historically there are low adoption rates among commercial customers in Washington. For a given payback period, residential customers are more likely to install solar than commercial customers. The maximum incentive of $5000/year is a limiting factor for commercial projects. Commercial customers must have quicker paybacks on investments.

Table 9: Summary of Market Potential Results by Scenario in 2020 and 2035

Scenario	2016-2020 Market Potential			2016-2035 Market Potential		
	Residential	Commercial	Total	Residential	Commercial	Total
Baseline	0	0	0	1	2	3
Extended ITC	0	0	1	8	18	26
Extended CRP	16	0	16	147	18	165
Best	33	1	35	297	11	309