Technical Appendix J:
Rooftop Solar Methodology and Potential

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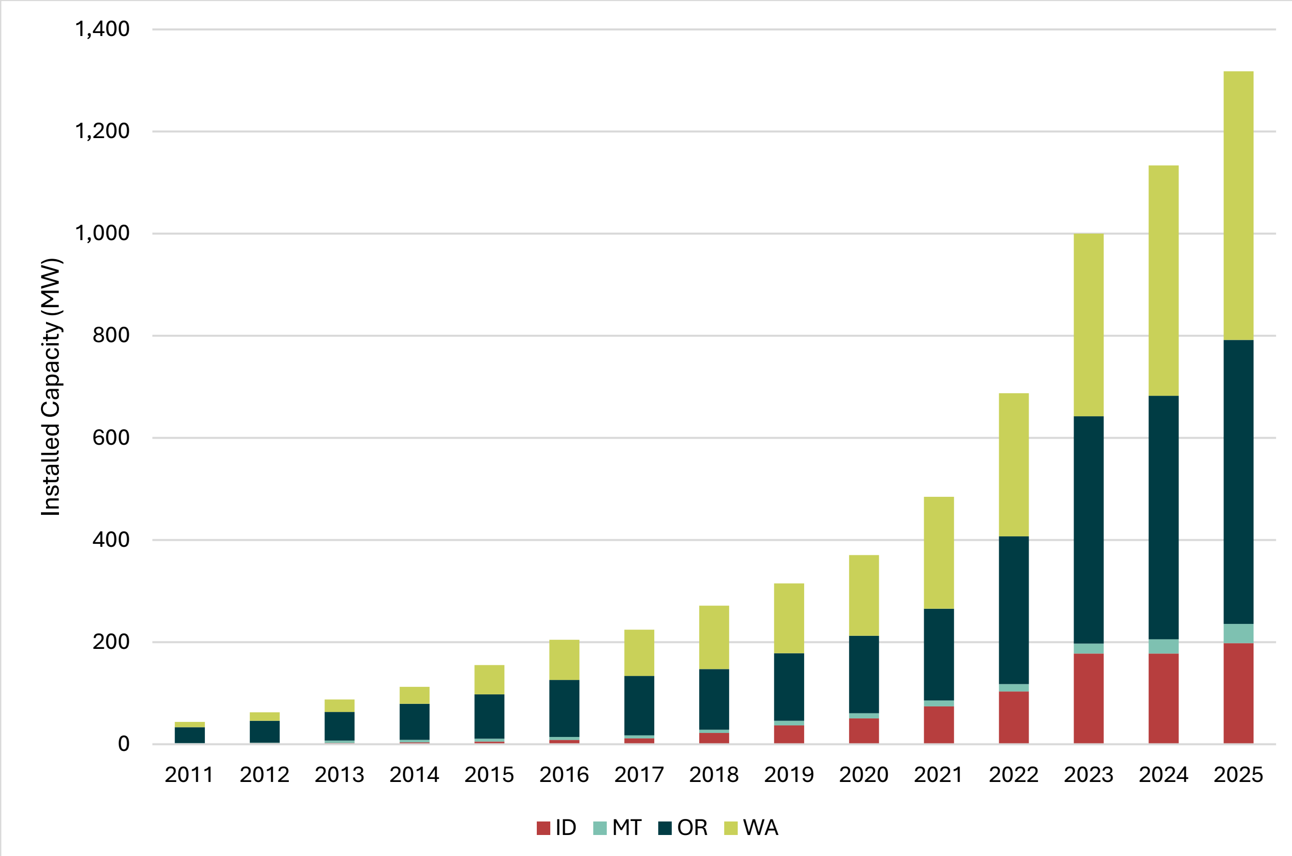
Background

Rooftop solar installations in the Pacific Northwest have increased significantly in recent years. Figure J - 1 shows the installed rooftop solar capacity in the four Northwest states from 2011-2025. In 2011, there were 44 MW of rooftop solar capacity installed and that number has grown to over 1,300 MW in 2025.

Figure J - 1: Rooftop Solar Capacity by State 2011-2025



Recent power plans have included rooftop solar data in the load forecasts, which means it has been treated as a load reduction in the models. The Council has not included rooftop solar as a resource to complete with others in the modeling and optimization process, largely because of the historically high cost of these resources relative to other generating resources. However, the cost of rooftop solar panels has been declining rapidly to the point that they now may be more competitive with some utility-scale generating resources as well as demand-side resources. Therefore, because of declining costs and significant growth in installations, the Council is treating rooftop solar as a competitive resource in the Ninth Power Plan.

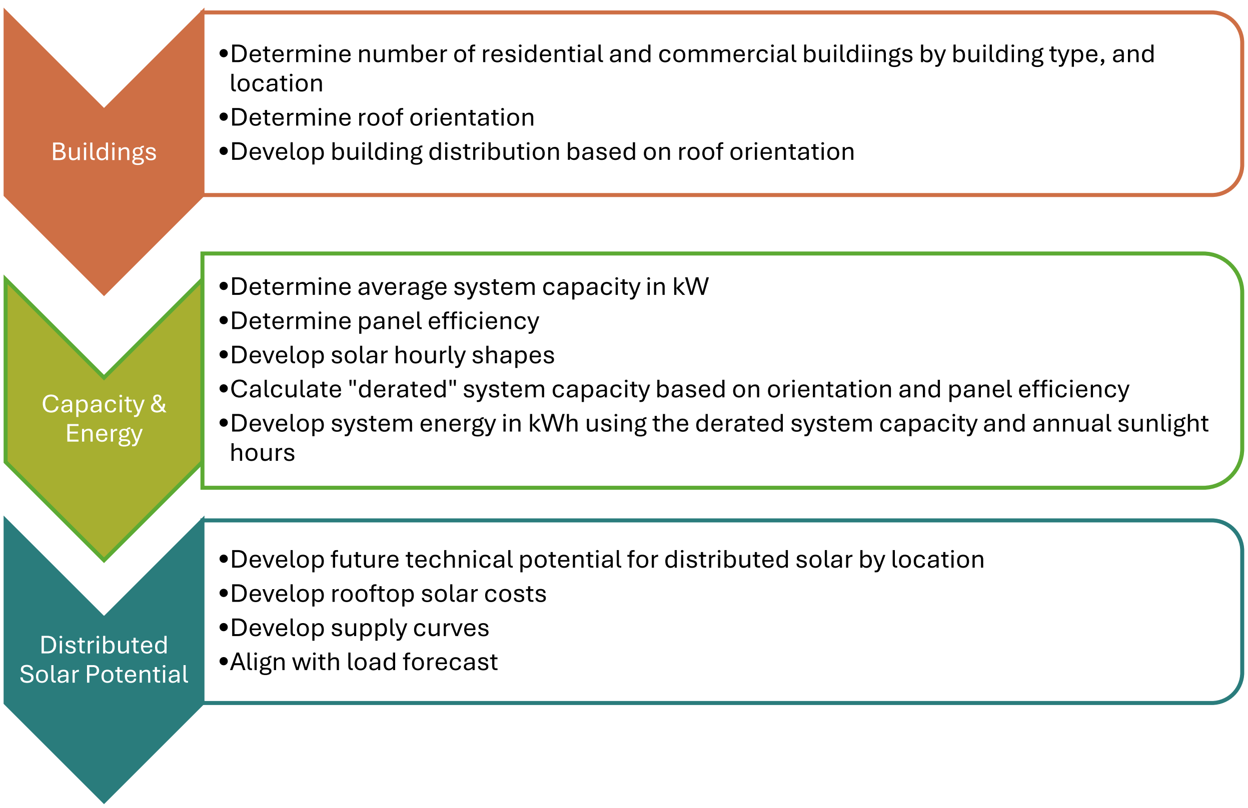
Rooftop solar refers to roof-mounted PV systems found in the residential, commercial, and industrial sectors. For the Ninth Plan, the Council developed detailed rooftop solar supply curves (levelized cost and energy production) for the residential and commercial sectors. The resource potential for rooftop solar was developed using bottom-up potential estimates like the approach used for energy efficiency. The bottom-up approach is based on the number of homes and businesses, and the amount of solar energy production for each, and then rolled up into regional potential estimates.

Rooftop solar installations are considered distributed energy resources (DERs) which refer to sources of electricity generation that are located at or near the point of consumption or “behind the meter” such as at a home or business. While DERs are a broad category, the Council focused on rooftop solar in the residential and commercial sectors for the Ninth Plan. These two applications are included because the region has seen significant increases in installations, along with cost reductions. Other DERs may include engine generators (natural gas, gasoline, propane), fuel cells, behind-the-meter wind turbines, but are far less common than rooftop solar.

Methodology for Estimating Rooftop Solar Potential

The high-level methodology used to develop rooftop solar potential is described in Figure J - 2. It includes estimating the number of homes and buildings that could host a rooftop solar system and the possible panel orientations. The energy production (kWh) is then estimated by combining the installed capacity (kW), the panel efficiency, orientation, shape, and annual sunlight hours. Finally, the total achievable potential is estimated by combining the number of buildings, energy production per building, and achievability factors including ramp rates. More detail about this methodology is provided below.

Figure J - 2: High-level Methodology



Building Stock and Roof Orientation

Estimates for the number of homes and commercial buildings were developed using the Residential Building Stock Assessment (RBSA) and the Commercial Building Stock Assessment (CBSA).[1] Table J - 1 shows the number of homes and commercial buildings in 2027 and the final year of the planning period in 2046.

Table J - 1: Numbers of Homes and Commercial Buildings

	2027	2046
Number of Homes	4.9 million	5.6 million
Number of Commercial buildings	350,000	430,000

Lawrence Berkeley National Lab's (LBNL's) Tracking the Sun data[2] were used to identify building and panel orientation. The report describes trends among grid-connected, distributed solar PV and paired PV plus storage systems in the United States. Panel orientation has been relatively constant in recent years. The report indicates that 54% of systems installed are facing south, 24% facing west, and most of the remainder facing east. A greater share of non-residential systems faces exactly due-south, likely due to greater prevalence of ground-mounting and flat rooftops than in the residential sector. Table J - 2 provides average panel orientation data for 2022 (latest date included in the report). These panel orientations were used in the residential sector only.

Table J - 2: Panel Orientation - Residential[3]

Panel Orientation	2022
North	4%
East	16%
South	54%
West	24%
Flat	2%

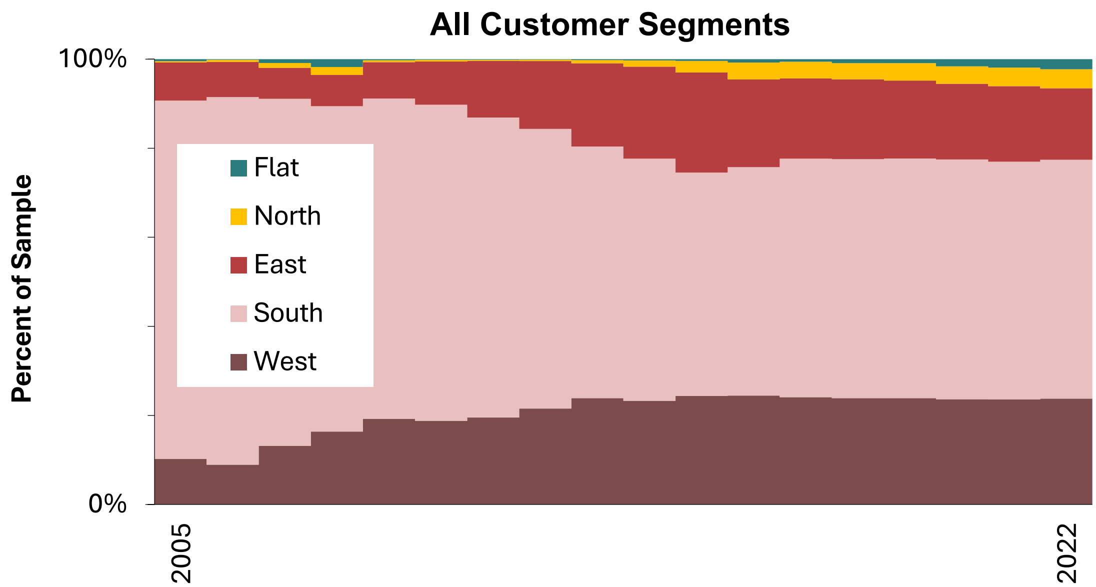
[1]Northwest Energy Efficiency Alliance 2022 Residential Building Stock Assessment. https://neea.org/residential-building-stock-assessment/

[2] LBNL Tracking the Sun Report Published on September 2023 can be found at https://emp.lbl.gov/sites/default/files/5_tracking_the_sun_2023_report.pdf.

[3] Ibid

Figure J - 3 provides panel orientation over time (2005 to 2022), illustrating how panel orientation has not changed significantly in recent years. For the Ninth Plan, the Council chose to use the 2022 average panel orientation in the analysis.

Figure J - 3: Panel Orientation Trends (2005 to 2022)[4]



For the commercial sector, south-facing orientation was assumed. The Council utilized NEEA CBSA data to estimate average roof area by building type for each of the four Northwest states. Then, based on data from LBNL,[5] the Council assumed 23% of roof area available for solar panels. The roof areas were then multiplied by 9.5 watts/sf[6] to obtain the system capacity. To simplify and reduce the number of permutations, two categories of buildings were created: large and small. Large buildings are those with greater than 100 kW of capacity, while small buildings have less than 100 kW of capacity. The overall average capacities by building category and state are shown in Table J - 3.

[4] Ibid
[5] Ibid
[6] L. Lisel, et.al., NREL Solar Ready Buildings Planning Guide, December 2009, https://docs.nrel.gov/docs/fy10osti/46078.pdf.

Table J - 3: System Size Estimates by State and Building Size Category

	Large Buildings	Small Buildings
ID	169 kW	38 kW
MT	226 kW	37 kW
OR	115 kW	43 kW
WA	135 kW	35 kW

System Capacity and Energy

Data for rooftop solar systems are reported by their system capacity. Ultimately, the amount of electricity produced by each installation is needed to estimate the potential electricity production per home or business. This section describes the process for developing these energy estimates.

Annual Sunlight Hours

Solar panels produce electricity only when the sun is shining, so it is important to estimate the annual sunlight hours, which can vary by location. Data from online sources as well as the Energy Trust of Oregon were used to estimate average sunlight hours by state. Table J - 4 shows the annual sunlight hours by state used in the analysis.

Table J - 4: Annual Sunlight Hours

State	Average Annual Sunlight Hours
Idaho	1497
Oregon	1171
Washington	1085
Montana	1537

Panel Efficiency

Module efficiencies vary considerably by manufacturer; however, LBNL's research[7] indicates the average panel efficiency for residential is 20.8%. Panel efficiency can be influenced by many factors such as temperature, irradiance level (sunshine), cell type and color, interconnection of the cell, shade, orientation, location, tilt, time of year (e.g., weather conditions and position of the sun) and contamination (e.g., dust, dirt, bird droppings, debris).

[7] LBNL Tracking the Sun Report Published on September 2023 can be found at https://emp.lbl.gov/sites/default/files/5_tracking_the_sun_2023_report.pdf.

Panel Capacity

Residential rooftop solar system sizes have been increasing over the past two decades. The median sizes in most states are now above 8 kW. The rated capacity was derated to account for orientation and panel efficiency. Table J - 5 provides system size by state for 2022 based on installations for the Northwest.

Table J - 5: System Size by State (2022 Installs)[8]

State	Average kW	Average Derated kW
Idaho	8.44	5.45
Oregon	8.87	5.72
Washington	9.47	6.11
Montana	10.80	6.97

Panel Energy

The energy production from rooftop solar panels was calculated by multiplying the derated panel capacity (kW) by the annual sunlight hours. Table J - 6 provides the calculated energy (kWh) values.

Table J - 6: Calculated Panel Energy

State	Average kWh
Idaho	8,150
Oregon	6,700
Washington	6,630
Montana	10,707

Solar Shapes

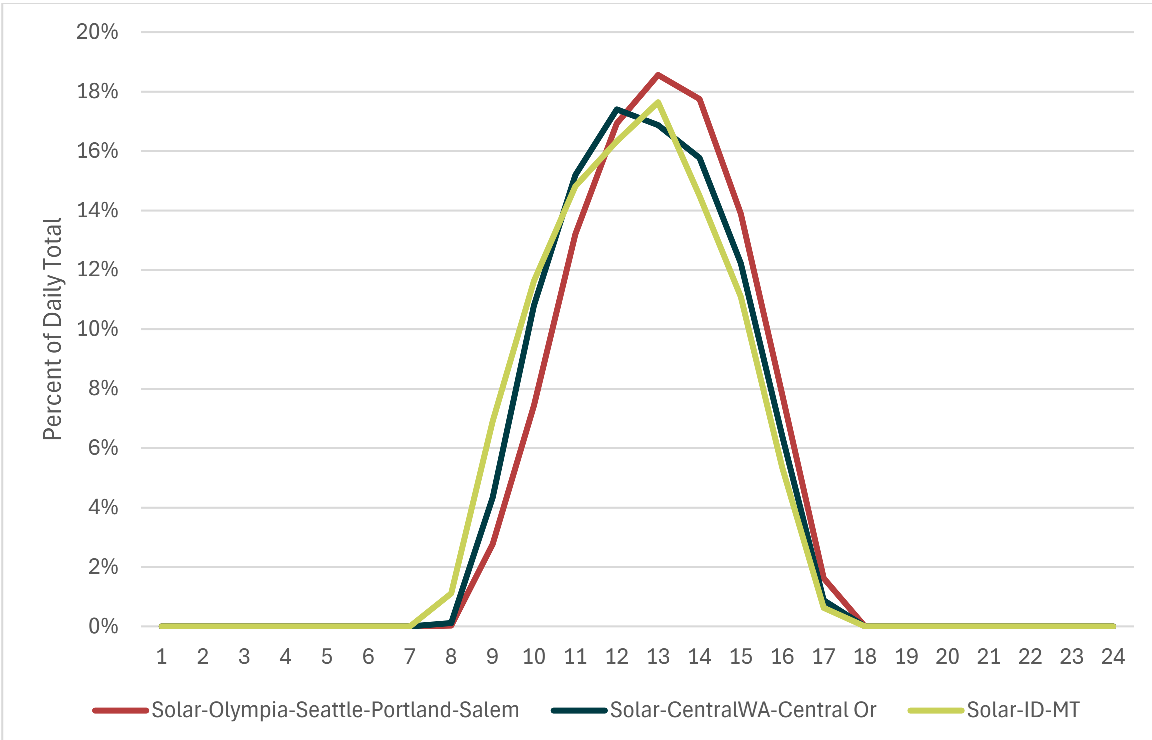
Solar profiles were developed for utility scale solar in the Ninth Power Plan (see Technical Appendix G – New Generating Resources). These same solar profiles are used for the rooftop solar assessment. The profiles correspond to three main areas in the region: West (west of the Cascades), Central (Central Oregon and Washington), and East (Idaho and Montana[9]. The profiles were normalized for

[8] Ibid

[9] There are two shapes (North/South) for each of the areas (West, Central, East) for a total of six shapes. However, the difference between the north and south shapes for each area is minute and not distinguishable in the graph, so only three shapes are shown.

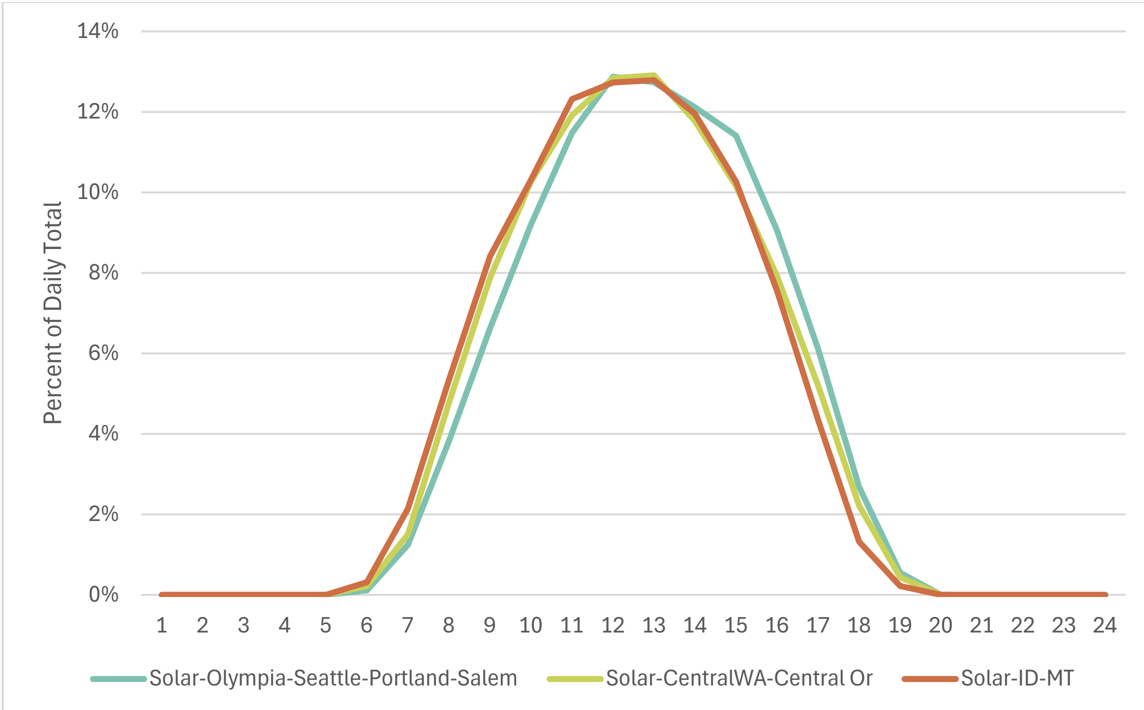
use in ProCost[10]. A sample of the solar shapes are shown in the next two figures. Figure J - 4 shows the peak day shape for January, and Figure J - 5 shows the peak day shape for August.

Figure J - 4: Solar Shapes – Peak Day January



[10] ProCost is the Council's Excel-based tool for calculating the levelized cost of energy efficiency and behind the meter solar measures: https://rtf.nwcouncil.org/work-products/supporting-documents/procost.

Figure J - 5: Solar Shapes – Peak Day August



Costs

Costs for residential systems were calculated using the average cost of $3.50 per watt. Costs are based on Energy Trust of Oregon and LBNL data. The cost per watt is then multiplied by the system size by state and by 1,000 to convert from watt to kW. Table J - 7 provides the calculated system costs by state. The analysis also includes an inverter replacement cost of $1,000. The inverter is assumed to be replaced after ten years (inverter life), while the life of the solar panels is assumed to be 25 years. This results in a one-time cost of $1,000 in year 10.

Table J - 7: Residential System Costs

State	$/watt	System Size (kW)	Total Cost
ID	$3.5	8.4	$29,560
MT	$3.5	10.8	$37,825
OR	$3.5	8.9	$31,070
WA	$3.5	9.5	$33,168

For the commercial sector, the cost was found to be $2.60/watt for small commercial systems and $2.17/watt for large commercial systems.[11] The data show that the cost per watt scales with system size so the resulting $2.60 per watt for commercial is lower than the $3.50 per watt for residential.

The federal investment tax credits (ITC) are included based on the specific scenario and sensitivity.

Solar Potential Development

Technical Potential

Technical Potential was calculated using the building stock multiplied by the derated capacity and energy values by panel orientation. Like energy efficiency, the technical potential is the maximum possible amount of energy that could be produced by installing rooftop solar panels on all homes in the region.

The formula for calculating the energy production of a solar system is detailed below:

$$\begin{aligned} Energy\ Production\ (kWh) &\\ = Panel\ Capacity(kW) * Annual\ Sunlight\ Hours(Hrs) * System\ \ Loss\ Factor &\\ * Orientation\ Derating & \end{aligned}$$

Once the energy production per home is calculated, it can then be multiplied by the number of homes to get to the technical potential.

Achievable Potential

Achievable potential is the result of applying various achievability factors to the technical potential. It is an attempt to estimate what is realistically achievable over the 20-year planning period. The standard maximum achievability assumed for rooftop solar installation is 85 percent. This factor has been used since the 1980's and attempts to capture the reality that even if a measure is paid for in full, there will still not be 100 percent adoption. There are also local limitations that impact the applicability of solar panels such as being located next to a tall building or in a dense forest. The locational limitations factor is estimated to be 15% and is based on professional judgement and confirmed by our advisory committees. Finally, the Council's load forecast included a conservative amount of rooftop solar adoption consistent with historical amounts. To avoid double counting that assumed adoption, a factor of 9.89 percent derates the achievability further. This brings the total maximum applicability to 60 percent. Table J - 8 summarizes these factors.

[11] LBNL Tracking the Sun Report Published on September 2023 can be found at https://emp.lbl.gov/sites/default/files/5_tracking_the_sun_2023_report.pdf.

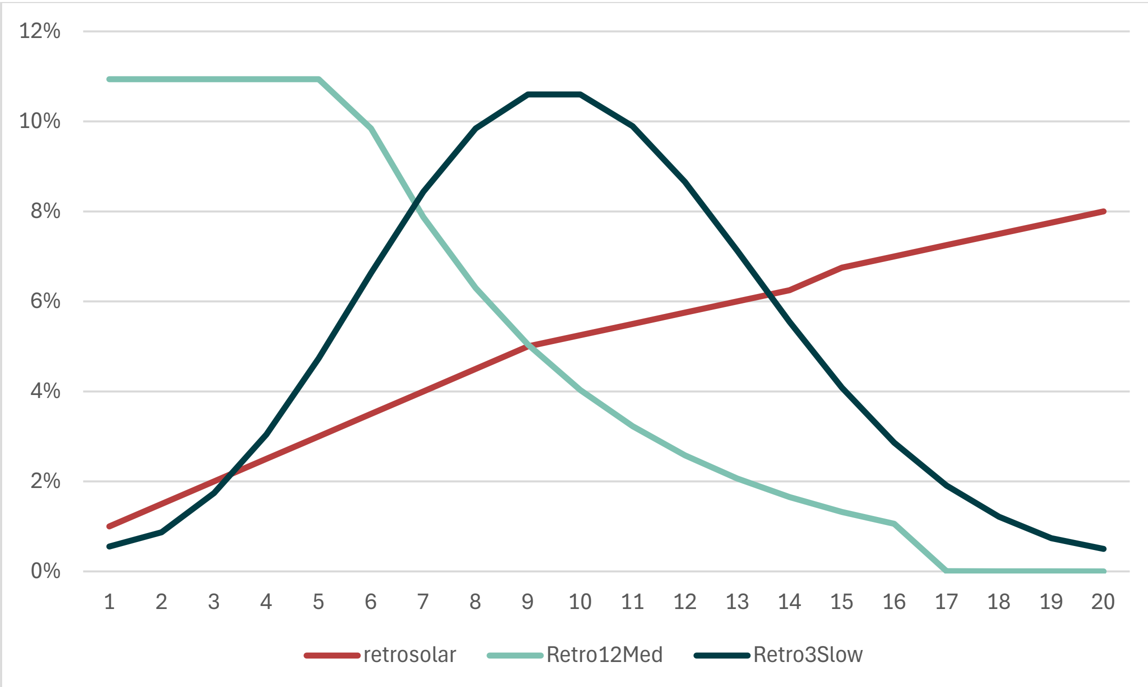
Table J - 8: Achievability Factors

Achievability Factor	Amount
Standard Max Achievability	85%
Included in Load Forecast + Saturation	9.86%
Locational Limitations	15%
Total Max Achievability	60%

In addition to the total achievability factors, limits are placed on the annual achievability using ramp rates. Ramp rates are a way to establish a pace of installation over time. For example, there are many factors that would prohibit, for example, the installation of rooftop solar on all available homes in the first two years. The ramp rates are the mechanism for simulating the maximum amount each year, and usually assumes subsequent years are increase as a program or infrastructure becomes more mature. For the rooftop solar analysis three ramp rates were applied (see Figure J - 6):

- Retrosolar – starts with a modest 1 percent and increases steadily over time to 8 percent per year. This rate is used for most locations.
- Retro3slow – starts slowly at less than 1 percent and then climbs quickly to just over 10 percent per year and then tails off again by year 20. Used in areas where the solar adoption rate is moderate.
- Retro12med – starts at 11 percent per year for five years and then drops off until all the potential is reached in year 17. Used in areas where the solar adoption rate is strong.

Figure J - 6: Ramp Rates for Rooftop Solar



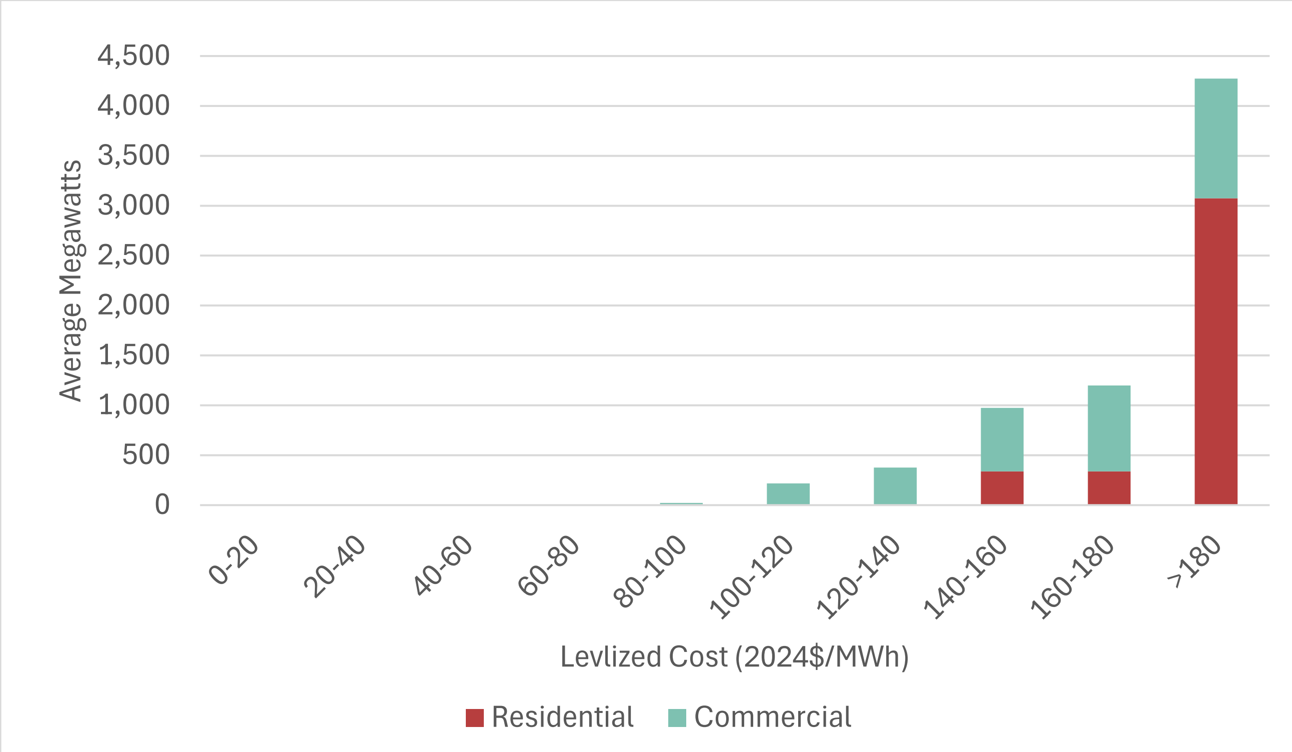
Rooftop Solar Supply Curve

The rooftop solar supply curve is shown in Figure J - 7. A supply curve shows the amount of rooftop solar energy generation available in different levelized cost bins. For example, there is just under 500 aMW of commercial rooftop solar potential available for less than $100/MWh. For less than $160/MWh, there is 2,000 aMW of combined commercial and residential potential.

This supply curve is used in the Plan's resource optimization models, primarily OptGen, to compare the costs of other generating resources and conservation resources to these rooftop solar resources. For example, if the forecast shows a future need, and there are resources available at $50/MWh, the rooftop solar would not be competitive. However, if the competing resources are costing $120/MWh, then some residential and commercial rooftop solar (approximately 1,300 aMW) would be competitive[12].

[12] Levelized cost isn't the only factor for determining resources. The shape and ability to address other system attributes can also be factors.

1 **Figure J - 7: Rooftop Solar Supply Curve**



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3 Figure J - 8 shows the annual incremental potential (aMW) which includes the ramp rates.

4 **Figure J - 8: Rooftop Solar Annual Incremental Potential**

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Rooftop Solar Potential by Zone

Table J - 9 shows the total achievable potential in 2046 for the commercial and residential sectors by modeling zone. These modeling zones are used throughout the Ninth Plan.

Table J - 9: 20-year Achievable Potential (aMW) by Modeling Zone

Zone	Residential	Commercial	Total
AVA – Avista Utilities	248.54	58.30	306.84
BPA_IDMT – Bonneville Power Administration Idaho and Montana	104.93	83.32	188.25
BPA_OR – Bonneville Power Administration Oregon	175.04	66.36	241.40
BPA_WA – Bonneville Power Administration Washington	563.39	133.00	696.39
CCPUD – Chelan County PUD	20.77	7.22	27.99
DCPUD – Douglas County PUD	17.33	9.26	26.59
GCPUD – Grant County PUD	20.85	16.91	37.76
IPCO – Idaho Power Company	469.98	161.97	631.94
NWMT – NorthWestern Energy Montana	93.77	79.37	173.15
PACE – PacifiCorp, East	89.93	55.47	145.40
PACW – PacifiCorp, West	345.63	221.46	567.09
PGE – Portland General Electric	300.31	146.14	446.45
PSE_Central – Puget Sound Energy, Central	194.66	34.70	229.36
PSE_North – Puget Sound Energy, North	121.66	34.70	156.36
PSE_Olympia – Puget Sound Energy, Olympia	80.87	31.45	112.32
SCL – Seattle City Light	167.58	55.46	223.04
TPWER – Tacoma Power	59.32	3.45	62.77
Totals	**3074.57**	**1198.54**	**4273.11**

Adjusting for Load Futures and Scenarios

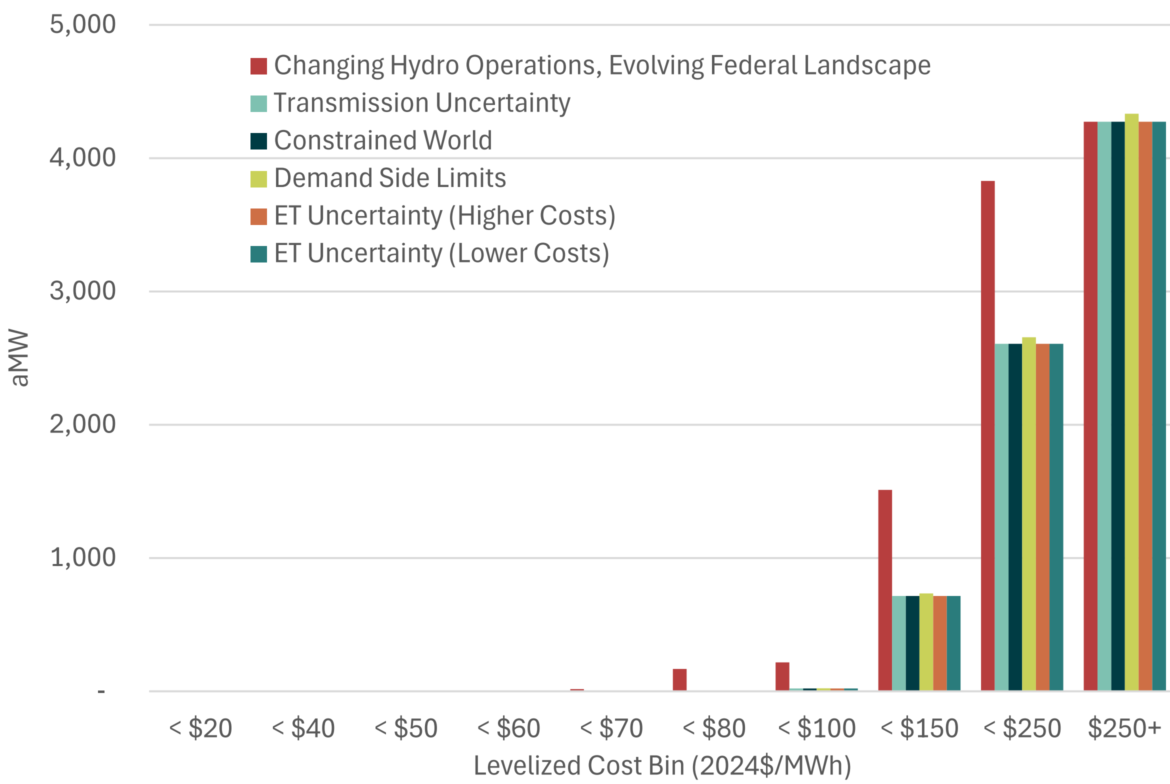
There is ultimately not a single set of rooftop solar supply curves for the Ninth Plan, but rather many variations, depending on the load future and analysis scenario being run in the model. Load futures and scenarios are similar in that they can both have changing assumptions that alter the shape, magnitude, and/or costs of the rooftop solar supply curves; however, they are different in that all load futures are present in every scenario, whereas each scenario is distinct from one another.

The sensitivities are designed to examine how rooftop solar, and other demand and supply side resources, may be selected differently depending on several different important factors, such as:

- whether or not federal tax incentives are available for rooftop solar
- whether rooftop solar is available according to the timeline assumed in the starting point

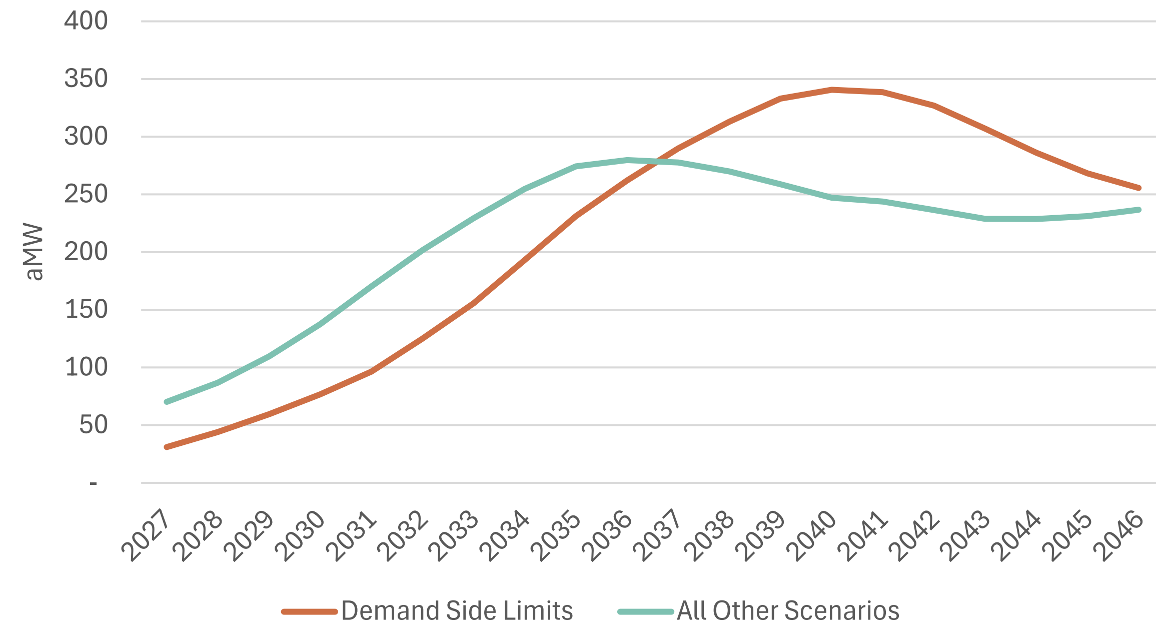
Tax credits are included in all sensitivities of the Changing Hydro Operations scenario and the Evolving Federal Landscape sensitivity of the New Resource and Transmission Risk scenario, but excluded in all others. Figure J - 9 shows the effect of including or excluding the tax credits on the rooftop solar supply curves.

Figure J - 9: Final Set of Supply Curves Used Across All Ninth Plan Sensitivities



The pace of adoption of rooftop solar was more limited in the Demand Side Resource Limitations scenario, which means that slower ramp rates were used relative to all other scenarios. Figure J - 10 shows the effect of the slower ramp rates on incremental available potential in the earlier years of the Plan period. Technical Appendix N – Scenario Modeling and Results provides more information on the specific assumptions in each scenario.

1 **Figure J - 10: Annual Incremental Potential Across All Ninth Plan Sensitivities**



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