**Date:** September 28, 2012

**To:** PacifiCorp

**From:** The Cadmus Group, Inc.

**Re:** Revised Overview of PV Inputs, Data Sources, and Potential Study Results

# Introduction

The Cadmus Group, Inc., under contract to PacifiCorp, has calculated the predicted technical potential, market potential, and levelized cost of energy for solar photovoltaic (PV) systems installed and operating in PacifiCorp territory from 2013-2032. The results of this analysis will be used in PacifiCorp's 2013 Integrated Resource Plan (IRP).

This memorandum outlines the assumptions, data sources, and preliminary results of Cadmus' analysis. Preliminary results were discussed at a stakeholder meeting on August 24, 2012. Based on feedback received at that meeting, this memorandum reflects relevant updates to assumptions, methodology, and results. Further discussion of all findings will be included in the forthcoming report.

# Technical Potential

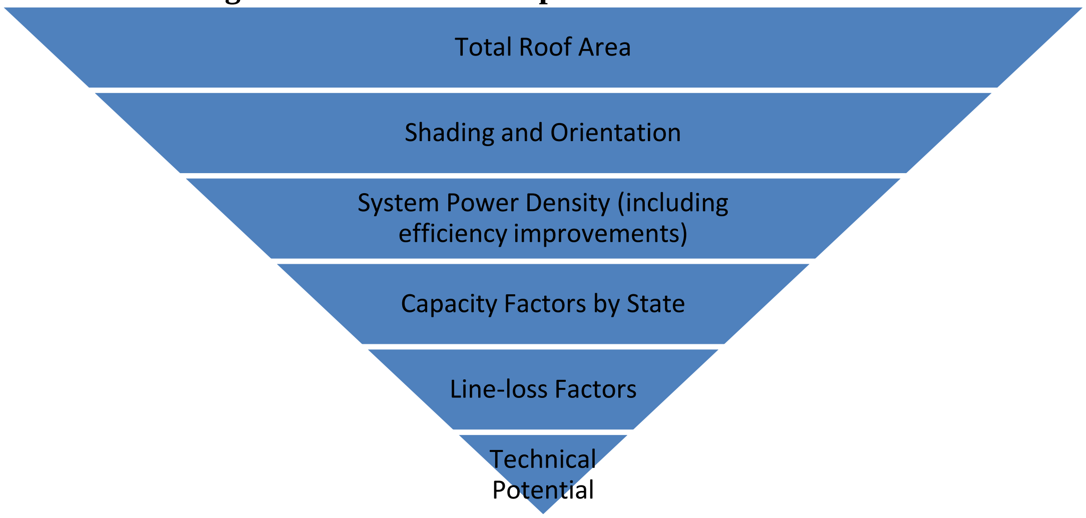
## Methodology

Determining the technical potential for solar PV in PacifiCorp's territory primarily involves estimating the roof area available for the residential and non-residential building stock over the study period, combined with relevant industry data and projections for system power density (installed kW per square foot) and capacity factor projections.

Cadmus used building stock data gathered during PacifiCorp's Energy Decisions Survey (EDS), conducted in 2005 for commercial and 2006 for residential, combined with the most recent customer data available and relevant building characteristic assumptions, to identify the total roof area expected to be feasible for installing solar PV systems. From there, Cadmus conducted a literature review of typical PV system power density and expected efficiency improvements over the 20-year study period. These data were used to calculate the expected system power density (kW per square foot of roof area). Finally, the PVWatts tool, developed by the National Renewable Energy Laboratory (NREL), was used to calculate residential and non-residential capacity factor values for each state.

Figure 1 depicts the high-level steps for determining the technical potential for solar PV. Technical and market potential were adjusted to account for transmission-line losses based on line-loss data received from PacifiCorp.

**Figure 1: Calculation Steps for Technical Potential**




## Data Sources and Assumptions

Cadmus used several relevant sources to analyze the technical potential in each state, as described in Table 1.

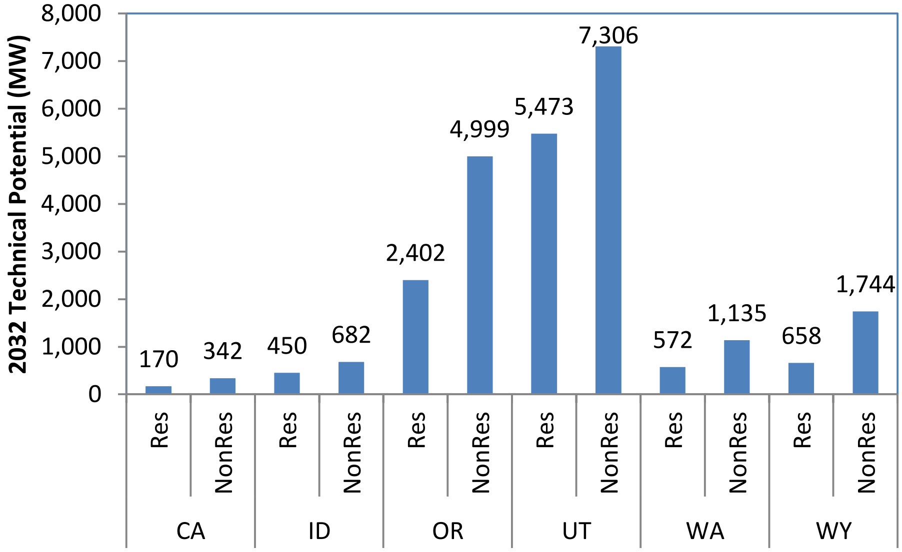
**Table 1: Data Sources Used in Solar PV Technical Potential Calculations**

| Input | Source | Website Link |
| --- | --- | --- |
| Available Roof Area per Building Type (Commercial) | PacifiCorp Energy Decisions Survey (2005 and 2006) | N/A |
| Available Roof Area per Building Type (Residential) | | N/A |
| Number of Customers by Building Type (Commercial) | PacifiCorp Customer Forecast Used in 2013 IRP and 2011 Customer Information System | N/A |
| Number of Customers by Building Type (Residential) | | N/A |
| New Construction Rates by Building Type | PacifiCorp customer forecast Used in 2013 IRP | N/A |
| Portion of Roof Area Useable for Solar PV | Navigant Consulting, *PV Grid Connected Market Potential under a Cost Breakthrough Scenario*, 2004 | http://www.ef.org/documents/EF-Final-Final2.pdf |
| Power Density of Solar PV | U.S. Department of Energy, *Photovoltaics - Energy for the New Millennium: The National Photovoltaics Program Plan 2000-2004*, DOE/GO-10099-940 (Washington, DC, January 2000) | Available upon request |

## Results

The predicted 20-year technical potential for solar PV in each of the states in PacifiCorp's territory is shown in Figure 2. The combined technical potential is 9,725 MW[1] for the residential sector; 16,208 MW for the nonresidential sector; and 25,933 MW overall.

**Figure 2: 2032 PacifiCorp Solar PV Technical Potential by State and Sector**




The state-specific technical potential is driven largely by the building stock within PacifiCorp's territory in each state. However, high technical potential alone does not drive market potential, as discussed in the following section. Also, the technical potential values discussed here will be significantly constrained by financial and other factors.

# Market Potential

## Methodology

The rate of assumed market penetration is based on actual capacity installed relative to estimated technical potential, for the corresponding year, in each state. Cadmus obtained installed capacity data from January 2010 through July 2012 net metering agreements, provided by PacifiCorp for each state. In addition, PacifiCorp provided projections for the remainder of 2012. These data are shown in Table 2.

[1] All capacity results reported in this memorandum refer to direct current (DC) capacity values, unless otherwise noted.

**Table 2: Installed Solar PV Capacity by State and Sector 2010-2012**

| | | Installed Capacity (MW) | | |
|---|---|---|---|---|
| **State** | **Sector** | **2010** | **2011** | **2012*** |
| CA | Res | 0.027 | 0.108 | 0.272 |
| | NonRes | 0.002 | 0.027 | 0.319 |
| ID | Res | 0.024 | 0.008 | 0.086 |
| | NonRes | 0.013 | 0.166 | 0.002 |
| OR | Res | 1.593 | 1.964 | 2.679 |
| | NonRes | 1.564 | 3.322 | 3.785 |
| UT | Res | 0.561 | 0.797 | 1.032 |
| | NonRes | 0.486 | 1.229 | 3.917 |
| WA | Res | 0.055 | 0.064 | 0.104 |
| | NonRes | 0 | 0.078 | 0.023 |
| WY | Res | 0.075 | 0.029 | 0.041 |
| | NonRes | 0.081 | 0.053 | 0.024 |
| Total | Res | 2.335 | 2.97 | 4.214 |
| | NonRes | 2.146 | 4.875 | 8.07 |

*Note: 2012 is based on historical data through July and projected data for August-December.

Using the data in Table 2, Cadmus calculated the average annual percentage of the technical potential achieved in the states with long-term incentive programs (Oregon and California) and in the states without incentive programs (Washington, Idaho, and Wyoming). Cadmus used an average of the market potential in Oregon and California to estimate the long-term market penetration for Utah. Each state was assigned an annual market penetration rate based on the presence, or lack of presence, of an incentive program in the state.

Although installation rates, relative to technical potential, were higher in Utah than in the non-program states, the Utah incentive program is relatively new and likely does not accurately represent the long-term impacts of a mature and long-running incentive program. Therefore, using the installation data to date for Utah could under-represent long-term market penetration rates.

This methodology, which was used for calculating market penetration for the 2013 IRP, was updated from the methodology used in the 2011 IRP. The market penetration rate used in the 2011 IRP was based upon PV incentive programs throughout the United States for which capacity installed data were available. Very few of the states in PacifiCorp's territory had this type of data available at that time and, in addition, most of the data were outdated. (Note that in the Results section, Table 4 shows the market penetration rates used in the 2011 IRP and those used in this study.)

## Data Sources

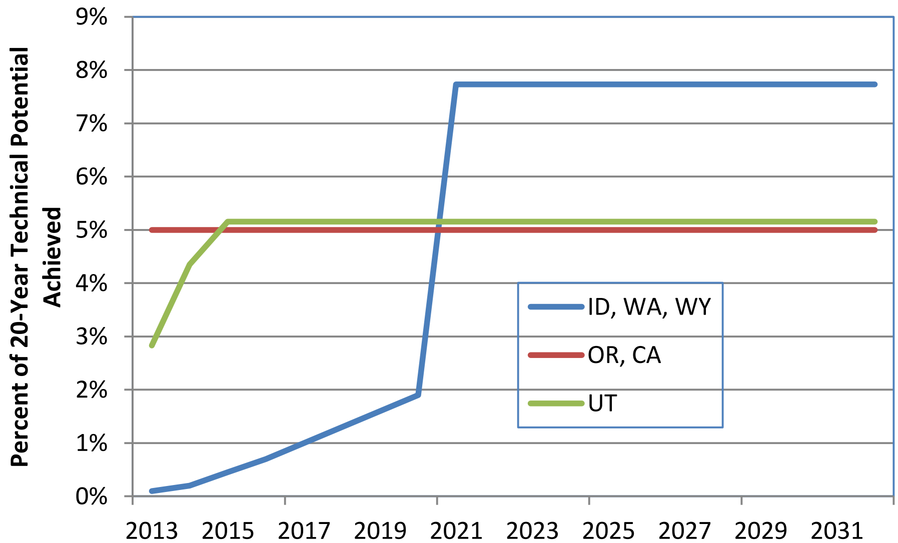
Cadmus used a combination of reported actual capacity installed, by state and sector; technical potential calculated as described above; and ramping rates to calculate the annual and total market potential for the residential and non-residential sectors in each state. These data sources are listed in Table 3.

**Table 3: Data Sources and Assumptions for Solar PV Market Potential**

| Input | Source | Website Link |
|---|---|---|
| Installed Capacity[2] | Based on executed net metering agreements, totals provided by PacifiCorp | N/A |
| Ramp Rate (for states without incentive programs) | Lost Opportunity Emerging Technology Ramp Rate | www.nwcouncil.org/energy/powerplan/6/default.htm |
| Ramp Rate (OR and CA)[3] | Assumed flat ramp rate of 5% per year over 20 years, to reflect presence of established incentive program | N/A |
| Ramp Rate (UT only) | Assumes initial two-year period to ramp up and maintain consistency with program filing | N/A |

The ramp rates are used to adjust annual market potential numbers and account for factors such as market momentum, supply chain initialization, and consumer education. The ramp rates, shown in Figure 3, do not impact the 20-year total technical or the market potentials.

**Figure 3: Annual Ramp Rates Applied to Long-Term Potential Estimates**




2 Values from the last quarter of 2012 are the projected values provided by PacifiCorp for use in this analysis.

3 At PacifiCorp's direction, 2013 and 2014 market potentials for Utah were fixed to match program filing.

## Results

As shown in Table 4, the methodology for the 2013 IRP has resulted in an increase in estimated market penetration for states with existing incentive programs (OR, CA, and UT), as compared to the 2011 study. Values in the table represent the average percentage of the 20-year technical potential acquired annually.

**Table 4: Annual Market Penetration Rates Used in the 2011 and 2013 IRPs**

| | | | Annual Market Penetration Rate | |
|---|---|---|---|---|
| Program Assumed? | State | 2011 IRP | Residential | Non-Residential |
| No | WA | 0.02% | 0.02% | 0.01% |
| | ID | 0.01% | | |
| | WY | 0.01% | | |
| Yes | OR | 0.02% | 0.14% | 0.08% |
| | CA | 0.02% | | |
| | UT | 0.02% | | |

Table 5 summarizes the technical and market potential results for the residential and non-residential sectors in each state. A total of 428 MW of installed capacity may be achieved over the six states by 2032.

**Table 5: 20-Year (2032) Solar PV Technical and Market Potential Results**

| State | Sector | 20 Year Technical Potential (MW) | 20 Year Market Potential (MW) |
|---|---|---|---|
| CA | Res | 170 | 4.7 |
| | NonRes | 342 | 5.2 |
| ID | Res | 450 | 1.6 |
| | NonRes | 682 | 1.4 |
| OR | Res | 2,402 | 66 |
| | NonRes | 4,999 | 76 |
| UT | Res | 5,473 | 151 |
| | NonRes | 7,306 | 111 |
| WA | Res | 572 | 2.0 |
| | NonRes | 1,135 | 2.3 |
| WY | Res | 658 | 2.4 |
| | NonRes | 1,744 | 3.5 |
| Total | Res | 9,725 | 228 |
| | NonRes | 16,208 | 199 |

In addition to technical and market potential system capacities, Table 6 lists the expected average Megawatt (aMW) potential values.[4]

**Table 6: 2032 Technical and Market Penetration (aMW)[5]**

| State | Sector | Technical Potential (aMW) | Market Potential (aMW) |
|---|---|---|---|
| CA | Res | 23 | 0.7 |
| | NonRes | 46 | 0.7 |
| ID | Res | 65 | 0.3 |
| | NonRes | 97 | 0.2 |
| OR | Res | 322 | 9.5 |
| | NonRes | 669 | 11 |
| UT | Res | 816 | 24 |
| | NonRes | 1,079 | 17 |
| WA | Res | 76 | 0.3 |
| | NonRes | 149 | 0.3 |
| WY | Res | 106 | 0.4 |
| | NonRes | 275 | 0.6 |
| Total | Res | 1,408 | 35 |
| | NonRes | 2,316 | 30 |

# Levelized Cost of Energy

## Methodology

The levelized cost, which is based on a single representative solar PV system, compares the life-cycle costs to the energy savings. It is calculated based on the Total Resource Cost (TRC) perspective for all states except Utah, where the Utility Cost Test (UCT) is the accepted perspective. Levelized cost is calculated separately for residential customers (separated into single-family and multifamily buildings) and commercial customers (a category that includes health, lodging, large office, large retail, and school buildings).

For both the TRC and the UCT, the costs are then divided by the electricity generation of the system over its life to obtain the levelized cost of energy. The energy production includes a line-loss factor, as provided by PacifiCorp. This varies by state and sector. The energy production over the life of the system takes into account system performance degradation.

4 One aMW=8,760 Megawatt-hours (MWh).

5 Note that values in this table include performance degradation losses for systems installed prior to 2032.

### TRC

The TRC levelized cost consists of these elements:

- The installation cost, less the federal tax credit for systems installed before 2017. The installation cost is based upon the average system size for that sector. Installation costs also account for expected cost trends over the next 20 years.
- The federal tax incentive, which is 30% of the installed system cost and is unaffected by any utility or state rebates received. The federal tax incentive expires December 31, 2016, and this is taken into account in the analysis. The state tax incentive is not included because the TRC sees the incentive as a benefit to the customer who installs the system, but a cost to the state's taxpayers, making the net effect zero.
- The operations and maintenance (O&M) costs, which include replacing the inverter once over the life of the system. The costs are assumed to occur in year 15 and are adjusted for inflation.
- The program administration costs, including marketing expenses, which are assumed to be 10% of the total program cost. This estimate is based upon conversations with PacifiCorp about their typical program administration costs.
- Incentives are not included in the TRC because the TRC sees the incentive as a benefit to the customer who installs the system, but a cost to the ratepayers, making the net effect zero.

### UTC

The UCT levelized cost is the utility's cost of administering the program. This cost consists of:

- The administration and marketing costs are assumed to be 10% of the total program cost.
- The incentive amount is assumed to be 25% of installed cost after applying the federal tax credit[6], accounting for trends in incremental costs. State credits have no impact on the utility incentive amount.

Additionally, PacifiCorp's nominal discount rate of 6.88% is used along with an inflation rate of 1.9% to adjust the installation and O&M costs in future years. Cadmus also collected data on cost trends, module efficiency improvements, and module performance degradation to estimate the energy output of systems installed in future years and of systems as they age. The PVWatts model, developed by the National Renewable Energy Laboratory, was used to estimate the capacity factor of a typical system within each state during the first year of operation. Data Sources and Assumptions

Cadmus reviewed several sources of data for the analysis. The sources are listed in Table 7 by the input used in the analysis. A link to the website is provided if one is available. Where the report or data were not available online, interested parties may contact Cadmus or PacifiCorp to request a copy of the information.

[6] The incentive does not increase with the expiration of the federal tax credit in 2016.

**Table 7: Data Sources Used for the LCOE Analysis**

| Input | Source | Website Link (Where Available) |
|---|---|---|
| Installed Cost | California Solar Initiative Program Data downloaded July 2012 | http://www.californiasolarstatistics.ca.gov/current_data_files/ |
| Installed Cost | Utah Solar PV Incentive Pilot Program Data from 2011 | Provided by PacifiCorp |
| Installed Cost | Utah State Energy Program 2011 data | Provided by Utah State Energy Program |
| Installed Cost | Energy Trust of Oregon data | Provided by Energy Trust of Oregon |
| Inverter Costs | Solar Buzz website | http://www.solarbuzz.com/Inverterprices.htm |
| Annual Change in Installed Cost | Lawrence Berkeley National Laboratory. Tracking the Sun IV: The Installed Cost of Photovoltaics in the U.S. from 1998-2010. September 2011. | http://eetd.lbl.gov/ea/emp/re-pubs.html |
| O&M Cost | Arizona Renewable Energy Assessment by Black and Veatch; Comparative Costs of California Central Station Electricity Generation Technologies by the California Energy Commission with Aspen Environmental Group; and Renewable Energy Transmission Initiative for RETI Coordinating Committee | Provided by NREL in their 2007 comments |
| Tilt | Utah Solar PV Incentive Pilot Program Data for 2011 | Provided by PacifiCorp |
| Azimuth | Utah Solar PV Incentive Pilot Program Data for 2011 | Provided by PacifiCorp |
| Capacity Factor | PVWatts Solar Calculator | http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/ |
| Annual Change in Module Efficiency | "Solar Energy Technologies Program, Multi-Year Technical Plan 2003-2007 and beyond" US DOE EERE | Can be provided by Cadmus upon request. |
| Average Size | Utah Solar PV Incentive Pilot Program Data for 2011 | Provided by PacifiCorp |
| Average Size | Utah State Energy Program | Provided by the Utah State Energy Program |
| Average Size | Energy Trust of Oregon data for 2011 | Provided by Energy Trust of Oregon |
| Performance Degradation | PVWatts default model assumption | http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/derate.cgi |
| Measure Life | Assumptions used by National Renewable Energy Laboratory's (NREL's) System Advisor Model (SAM) | http://www.sam.nrel.gov |
| Federal Rebate | Database of State Incentives for Renewables and Efficiency | http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US37F&re=1&ee=1 |
| State Rebates | Database of State Incentives for Renewables and Efficiency | http://www.dsireusa.org/ |

## Overview of Installed System Cost Data

Cadmus gathered and reviewed installed system cost data from four main sources: (1) the Utah Solar PV Incentive Pilot Program; (2) the Utah State Energy Program; (3) the California Solar Initiative (CSI); and (4) the Energy Trust of Oregon Program. A comparison of the installed costs reported by these programs is presented in Table 8.

**Table 8: Comparison of Installed Costs for PV Systems in the U.S.**

| Size (kW) (CEC PTC AC)* | 2011 Utah Pilot Systems ( 2012 $/W) | 2011 Utah State Energy Program Systems (2012 $/W)** | 2011 CSI Systems (2012 $/W) | 2012 CSI Systems (2012 $/W) | Energy Trust of Oregon (2012 $/W)*** |
|---|---|---|---|---|---|
| < 5 kW | $6.57 | $7.56 | $7.94 | $7.46 | $7.70 |
| 5 to 10 kW | Sample size is too small | $6.84 | $6.40 | $5.91 | n/a |
| 10 to 30 kW | Sample size is too small | $8.14 | $6.13 | $5.20 | $7.21 |

*The California Energy Commission (CEC) PVUSA Test Conditions (PTC) module size was used.[7] The inverter efficiency was taken into account to convert from direct current (DC) to alternating current (AC).

**Values were converted from cost per DC watt at STC to cost per AC watt at PTC by assuming 1.2 W STC-DC per 1.0 W CEC PTC-AC.

***Energy Trust of Oregon provided average system cost data for residential and nonresidential systems. The < 5 kW system cost corresponds to residential systems (with an average size of 2.7 kW) and the 10 to 30 kW system cost corresponds to nonresidential systems (with an average size of 13.9 kW).

For the Utah and CSI system costs, Cadmus used the year that the customer first applied to the program, as this was assumed to be the best proxy of the year the customer received the price quote. Also, CSI systems with a third-party system owner were eliminated from the analysis since it was unknown whether these systems fell under a Power Purchase Agreement (PPA), which generally results in a higher reported cost. Sales tax was removed from California costs to isolate the cost of PV equipment and installation.

## Residential and Commercial Inputs to Levelized Cost Analysis

As part of this study, Cadmus reviewed relevant data on installed cost trends for solar PV. Presently, solar PV system costs are at a historic low and are expected to continue to decrease. Due to a large influx of inexpensive PV modules over the past several years, primarily from China, costs have decreased more rapidly than would be suggested by longer-term trends. Pending tariff regulations from the Department of Commerce on Chinese-manufactured solar PV modules will likely also play a role in leveling out the decline in solar PV prices.

It is not clear that the present rate of cost reductions is sustainable beyond the short-term and there is significant uncertainty around short-term price predictions. As a result, Cadmus used

[7] PVUSA Test Conditions are 1,000 Watts of solar irradiance per square meter, 20 degrees Celsius air temperature, and wind speed of 1 meter per second at 10 meters above ground level. STC are 1,000 Watts of solar irradiance per square meter, 25 degrees Celsius cell temperature, air mass equal to 1.5, and ASTM G173-03 standard spectrum. The PTC rating, which is lower than the STC rating, is a more realistic measure of module output because the test conditions better reflect "real-world" solar and climatic conditions, compared to the STC rating.

long-term historical cost data presented in the LBNL study referenced in Table 9, representing a conservative predictor of future cost trends.

A summary of the inputs which were used for the analysis are provided in the tables below. Table 9 lists the assumptions for residential, single-family systems.

**Table 9: Residential Single Family Assumptions[8]**

| Input | Value | Reasoning |
|---|---|---|
| Average size | 3 kW (CEC PTC AC) | Average residential system size in the 2011 Utah Solar PV Incentive Pilot Program is 3.2 kW. The average residential system size in the USEP in 2011 is also 3.2 kW. The average size in the ETO program to-date in 2012 is 2.7 kW. |
| Measure Life | 30 years | Typical module manufacturer warranty period is 25 years. The NREL System Advisor Model (SAM) assumes a 30-year life. |
| 2013 Installation Cost | $7.45/W | Average cost from the programs reviewed |
| Annual change in nominal installation cost | -4.6% | Found in the LBNL study as the trend from 1998 to 2010; Supported by lower costs in Germany and Japan, which should be achievable in the U.S. as the market grows. Though costs have seen a larger annual decline in recent years (per LBNL, as much as 22% from 2010 to 2011), it is not expected that this will continue over 20 years. |
| O&M Cost | $2,133 nominal cost for inverter replacement in year 15 | Based on the Solarbuzz inverter costs reported for March 2012 of $0.711/W. Assumes one inverter replacement over the 30 year life. This is also within the range ($25-$100 per year) presented by NREL comments on 2007 report |
| Tilt | 32 degrees | Average residential system tilt in the Utah Solar PV Incentive Pilot Program from 2010 – 2011 |
| Azimuth | South | Average residential system azimuth in the Utah Solar PV Incentive Pilot Program from 2010 – 2011 |
| Inverter Efficiency | 95% | Typical inverter efficiency |
| Annual Change in Module Efficiency | 2.1% | US DOE EERE report on Solar Energy Technologies Program Multi-Year Technical Plan, average across all three classes of technology (mono-crystalline, poly-crystalline, and amorphous thin-film). |
| Annual Performance Degradation | 1% | PV Watts default derate value |
| Capacity Factor | Depends on location | From PV Watts |

[8] Note that some of the assumptions also apply to calculations made for the technical and/or market potential.

Table 10 lists the assumptions for multifamily, commercial, and industrial systems.

**Table 10: Multifamily, Commercial, and Industrial Assumptions**[9]

| Input | Value | Reasoning |
|---|---|---|
| Average size | 20 kW (CEC PTC AC) | The average commercial system size in the 2011 Utah Solar PV Incentive Pilot Program is 19.1 kW. The average size in the 2011 Utah State Energy Program was 11.5 kW. It is assumed that a full-scale incentive program would see more participants and larger systems. |
| Measure Life | 30 years | Typical module manufacturer warranty period is 25 years. The NREL System Advisor Model (SAM) assumes a 30 year life. |
| 2013 Installation Cost | $6.67/W | Average cost from the programs reviewed |
| Annual change in nominal installation cost | -4.6% | Found in the LBNL study as the trend from 1998 to 2010; Supported by lower costs in Germany and Japan which should be achievable in the U.S. as the market grows. Though costs have seen a larger annual decline in recent years (per LBNL, as much as 22% from 2010 to 2011), it is not expected that this will continue over 20 years. |
| O&M Cost | $14,220 nominal cost for inverter replacement in year 15 | Based on the Solarbuzz inverter costs reported for March 2012 of $0.711/W. Assumes one inverter replacement over the 30 year life. |
| Tilt | 25 degrees | Average commercial system tilt in the Utah Solar PV Incentive Pilot Program from 2010 – 2011 |
| Azimuth | South | Average commercial system azimuth in the Utah Solar PV Incentive Pilot Program from 2010 – 2011 |
| Inverter Efficiency | 95% | Typical inverter efficiency |
| Annual Change in Module Efficiency | 2.1% | US DOE EERE report on Solar Energy Technologies Program Multi-Year Technical Plan, average across all three classes of technology (mono-crystalline, poly-crystalline, and amorphous thin-film). |
| Annual Performance Degradation | 1% | PV Watts default derate value |
| Capacity Factor | Depends on location | From PV Watts |

9 Note that some of the assumptions also apply to calculations made for the technical and/or market potential.

## Results

As shown in Table 11, LCOE is expected to decrease over the next 20 years. One notable exception to the general downward trend in costs is the expiration of the Federal Investment Tax Credit (ITC) at the end of 2016, causing the LCOE to increase before resuming a downward trend through 2032. The markedly lower LCOE for Utah, as discussed previously, is due to the use of the Utility Cost Test, whereas the remainder of the states' LCOE is calculated using the Total Resource Cost test.

**Table 11: Solar PV Levelized Cost of Energy Summary Results**

| State | Sector | Levelized Cost* | | | Capacity Factor |
|---|---|---|---|---|---|
| | | 2013 ($/kWh) | 2017** ($/kWh) | 2032** ($/kWh) | |
| CA | Res | $0.30 | $0.35 | $0.18 | 0.16 |
| | NonRes | $0.27 | $0.32 | $0.16 | 0.15 |
| ID | Res | $0.28 | $0.33 | $0.17 | 0.16 |
| | NonRes | $0.26 | $0.30 | $0.16 | 0.16 |
| OR | Res | $0.30 | $0.35 | $0.18 | 0.17 |
| | NonRes | $0.27 | $0.32 | $0.17 | 0.17 |
| UT | Res | $0.07 | $0.06 | $0.03 | 0.17 |
| | NonRes | $0.06 | $0.05 | $0.03 | 0.17 |
| WA | Res | $0.30 | $0.36 | $0.18 | 0.19 |
| | NonRes | $0.28 | $0.33 | $0.17 | 0.19 |
| WY | Res | $0.25 | $0.30 | $0.15 | 0.16 |
| | NonRes | $0.23 | $0.27 | $0.14 | 0.16 |

*As noted, Utah LCOE is calculated using the UCT, while the other states use the TRC test.
**The Federal Investment Tax Credit (ITC) is set to expire at the end of 2016. LCOE estimates for 2017 and 2032 assume that the ITC is not extended or renewed.

## Responses to Stakeholder Comments on Customer-Sited Generation, August 24, 2012

**PV 1. Analysis should include reduction in system cost over time. New NREL Renewable Electricity Futures Study has information on current trends.**

Cadmus' analysis assumes that nominal costs decrease by 4.6% per year based on Lawrence Berkeley National Laboratory "Tracking the Sun IV: The Installed Cost of Photovoltaics in the U.S. from 1998-2010," September 2011. The focus of this study was the historical cost trends of solar PV, based on extensive historical data from multiple states. The NREL study, on the other hand, focused on assessing the potential impacts of very high renewable-energy penetration rates, with a much broader scope that includes both renewable and non-renewable generation sources and cost trends.

In Cadmus' opinion, the LBNL report is more focused on the historical costs of solar PV and is a more appropriate source for cost assumptions for this potential study. Furthermore, the use of this longer-term historical cost data will help to minimize the present market uncertainty around solar PV module prices, which have been falling more rapidly than normal in recent years due to a high volume of Chinese-manufactured solar PV modules in the marketplace. These market conditions make shorter-term projections of cost reductions uncertain. Therefore, Cadmus advises that the IRP process use a more conservative, historical basis for cost-reduction scenarios.

**PV 2. Analysis assumes federal incentive is not renewed when it expires in 2017. Suggestion of an IRP scenario where the federal tax credit stays in place throughout study period.**

PacifiCorp will include a number of scenarios for which the federal tax credit stays in place through 2020

**PV 3. Percentage of technical potential deemed achievable is too low.**

a. **Market penetration is based on historic achievements which may have been pilots or otherwise constrained by available incentives.**

   In Cadmus' updated analysis, market penetration rates are based on the existence (or lack thereof) of an incentive program in each state. The market penetration rates for states with incentive programs (CA, OR, and UT) are derived from historical installation rates in Oregon and California, where longer-term incentive programs are in place.

b. **Historic data taken from the Open PV database, which is based on voluntary reporting, may understate actual installations.**

   PacifiCorp has provided Cadmus with data on actual installations (number of sites and total capacity) in its service territory. These data will be used in place of the OpenPV data. Cadmus compared these data to the technical potential identified in the 2010 potential study to determine the market penetration for states with, and without, incentive programs. These market penetration rates are applied to Cadmus' updated estimates of technical potential to calculate the 20-year market potential in each state.

c. **Relationship between technical and achievable potential in Oregon and Utah seems incorrect – Utah has higher technical potential, but Oregon has higher achievable.**

   This was a result of the reported installation rates obtained from OpenPV. With the new installation rate data, Utah has slightly larger market potential than Oregon.

d. **Achievable potential of ~1 MW over 20 years in Idaho seems too low.**

   Based on the new data, Idaho has a 20-year market potential of 3 MW.

e. **Suggestion to look at Arizona as an example of what could be achieved with higher levels of funding.**

   As this is part of a 20-year planning process, relatively short-lived high incentive programs, such as recent programs in Arizona, may not provide a good representation of programs existing, or likely to exist in the region over the long term.

**PV 4. Assumed incentives are too high and not in line with Utah filing. Suggestion that $0.90 per Watt be used as an average assumption over the study horizon.**

The Utah filing set its incentive at 25% of system cost after netting out federal tax credits. The numbers presented in the Cadmus memos and accompanying workbook had not made this adjustment for the federal tax credit. The revised analysis is consistent with the Utah filing, with average 20-year incentives of $0.86/W and $0.77 for residential and non-residential systems, respectively.

**PV 5. Suggestion to model on a utility cost basis in all states.**

The Total Resource Cost test is used in all states except Utah to align planning and delivery. Modeling all states on a utility-cost basis risks the model selecting resources that cannot be acquired at the given cost based on cost-effectiveness rules in place in each state.

**PV 6. Provide the peak capacity contribution for solar PV.**

The peak capacity contribution being used for the 2013 IRP is 13.6%.