Capital Cost Review of Power Generation Technologies

Recommendations for WECC’s 10- and 20-Year Studies

Prepared for the Western Electric Coordinating Council
155 North 400 West, Suite 200
Salt Lake City, Utah 84103-1114

March 2014
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1 Introduction

1.1 Background

The Western Electricity Coordinating Council (WECC) has asked E3 to provide recommendations on resource cost and performance to use in the Transmission Expansion Planning and Policy Committee’s (TEPPC) 10- and 20-year studies. E3 provided generation cost and performance assumptions in 2009 and 2011 to use as inputs in WECC’s 10-year study horizon. In 2012, E3 provided recommendations that also included guidance on potential future cost reductions for wind and solar technologies to serve as inputs to the 10- and 20-year studies. The recommendations in this document are updates to values previously provided by E3 to ensure continued currency and accuracy of these inputs to WECC’s modeling processes.

The role of generation and transmission capital costs in the 10-year study processes is summarized in Figure 1. In the 10-year study horizon, the primary analytical tool is production cost modeling, which performs a security-constrained economic dispatch for each hour over the year to minimize the operating costs across the WECC. The generation portfolio and transmission topology are determined exogenously. WECC staff, with assistance from stakeholders, develops assumptions for a 10-year “Common Case” as well as a number of “change cases” that alter some of these assumptions. In addition to the change in variable operating costs that result from alternative generation portfolios and/or transmission topology, there is a change in the cost of the
capital investments associated with the alternative physical system simulated in the change cases. In this context, the inclusion of resource capital costs in WECC’s study allows for a more complete assessment of the relative costs of each “change case” relative to the Common Case.

Figure 2 shows the role of capital costs as inputs in the 20-year study process, in which the expansion of generation and transmission is endogenous to the study. In this process, the Study Case Development Tool (SCDT) and the Network Expansion Tool (NXT)—together, the Long-Term Planning Tools (LTPT)—optimize the electric sector’s expansion subject to a large number of constraints in order to minimize the cost of delivered energy in 2034, including both the fixed costs of new investment and the variable costs of operation.

These dual roles establish the context under which E3 has conducted this review of generation resource cost and performance issues and assumptions. Given the long time frame of WECC’s study horizons, E3 has included both an assessment of present-day new generation resource characteristics and how those characteristics might evolve in the future. This report details the development of the recommended assumptions for each of the studies as well as the assumptions that informed them.
Figure 1. The role of generation and transmission capital cost assumptions as inputs to the 10-year studies
Figure 2. The role of generation and transmission capital cost assumptions as inputs to the 20-year studies
1.2 Technologies Considered

Table 1 lists the technologies that are included in E3’s scope. By request of WECC staff and stakeholders, E3 has added two energy storage technology options, reciprocating engines, and an additional geothermal technology subtype for the 2013-2014 study cycle. This set of resources is intended to be comprehensive of the new resources included or considered in WECC’s studies. For all technologies considered, E3 reviews cost assumptions used in the WECC models. E3’s recommendations on cost ensure that the values used in WECC’s studies represent the best available public information.
Table 1. Technologies included in E3’s scope of analysis

<table>
<thead>
<tr>
<th>Technology</th>
<th>Subtype</th>
</tr>
</thead>
<tbody>
<tr>
<td>Battery</td>
<td></td>
</tr>
<tr>
<td>Biogas</td>
<td>Landfill</td>
</tr>
<tr>
<td></td>
<td>Other</td>
</tr>
<tr>
<td>Biomass</td>
<td></td>
</tr>
<tr>
<td>Coal</td>
<td>Pulverized Coal (PC)</td>
</tr>
<tr>
<td></td>
<td>Integrated Gasification Combined Cycle w/ Carbon Capture &amp; Sequestration (IGCC w/ CCS)</td>
</tr>
<tr>
<td>Combined Heat &amp; Power</td>
<td>Small (&lt;5 MW)</td>
</tr>
<tr>
<td></td>
<td>Large (&gt;5MW)</td>
</tr>
<tr>
<td>Gas CCGT</td>
<td>Basic, Wet Cooled</td>
</tr>
<tr>
<td></td>
<td>Advanced, Wet Cooled</td>
</tr>
<tr>
<td></td>
<td>Basic, Dry Cooled</td>
</tr>
<tr>
<td></td>
<td>Advanced, Dry Cooled</td>
</tr>
<tr>
<td>Gas CT</td>
<td>Aeroderivative</td>
</tr>
<tr>
<td></td>
<td>Frame</td>
</tr>
<tr>
<td>Geothermal</td>
<td>Binary/Flash</td>
</tr>
<tr>
<td></td>
<td>Enhanced (EGS)</td>
</tr>
<tr>
<td>Hydro</td>
<td>Small</td>
</tr>
<tr>
<td></td>
<td>Large</td>
</tr>
<tr>
<td></td>
<td>Pumped Storage</td>
</tr>
<tr>
<td>Nuclear</td>
<td></td>
</tr>
<tr>
<td>Reciprocating Engine</td>
<td></td>
</tr>
<tr>
<td>Solar PV</td>
<td>Residential Rooftop</td>
</tr>
<tr>
<td></td>
<td>Commercial Rooftop</td>
</tr>
<tr>
<td></td>
<td>Fixed Tilt (1-20 MW)</td>
</tr>
<tr>
<td></td>
<td>Tracking (1-20 MW)</td>
</tr>
<tr>
<td></td>
<td>Fixed Tilt (&gt; 20 MW)</td>
</tr>
<tr>
<td></td>
<td>Tracking (&gt; 20 MW)</td>
</tr>
<tr>
<td>Solar Thermal</td>
<td>No Storage</td>
</tr>
<tr>
<td></td>
<td>Six Hour Storage</td>
</tr>
<tr>
<td>Wind</td>
<td>Onshore</td>
</tr>
<tr>
<td></td>
<td>Offshore</td>
</tr>
</tbody>
</table>
1.3 Assumptions

E3’s recommendations are based on the following assumptions:

1. Present-day capital costs correspond to systems and/or plants installed in 2013.

2. All resource costs are expressed in 2014 dollars.

3. Capital costs presented represent all-in plant costs and are inclusive of all engineering, procurement, and construction (EPC); owner’s costs; and interest during construction (IDC).

4. Fixed Operations and Maintenance (O&M) costs include labor and administrative overhead. Fixed O&M costs do not include property tax and insurance, which are evaluated separately (see Section 5.3.2 for further details on treatment of property tax & insurance).

5. All costs are intended to represent the average costs for new generation in the WECC; E3’s technology-specific regional multipliers (see Section 4) can be used to estimate plant capital costs for each state in the WECC.
2 Methodology

2.1 Present-Day Cost Review

In order to determine appropriate assumptions for resource costs for the array of generation technologies considered in the WECC modeling process, E3 conducted a thorough literature review. E3 aggregated information from a wide range of sources and used the results to inform recommendations for the capital and fixed O&M costs for each type of generation technology. Types of sources considered in E3’s review include:

- Studies commissioned by government entities (e.g. National Renewable Energy Laboratory (NREL), National Energy Technology Laboratory (NETL), Energy Information Administration (EIA)) of the comparative costs of generation technologies;
- Integrated resource plans published by utilities located in the WECC (e.g. NV Energy, Arizona Public Service Company (APS), PacifiCorp);
- Actual data on installed cost of generation technologies (e.g. CSI installation database, APS PV data)

A full list of the sources considered in the review of capital costs is included in Section 7.2.

Among the diverse sources surveyed in this study, there are a number of conventions used to report costs—both in terms of what cost basis year is used and whether reported costs are “overnight” or “all-in.” To facilitate the
comparison across sources with different conventions, E3 has made adjustments to the reported costs from each source such that the figures displayed in this report can all be interpreted as being all-in costs reported in 2014 dollars. Because of these adjustments, numbers in this report may not match those found in the original sources.

It should be noted that an approach that relies on publicly available data poses some challenges, particularly for technologies that are in evolutionary stages and whose costs are changing quickly. In some cases, a lack of publicly available data makes a robust characterization difficult; such was the case with both solar thermal technologies, coal plants using integrated gasification combined cycle (IGCC) technology with carbon capture and sequestration (CCS), and enhanced geothermal systems. Another challenge that arises is that the costs of some technologies are in a state of rapid change; under such circumstances, there is a natural time lag between the vintage of the published data and the technology as it is currently installed. This was E3’s experience with solar photovoltaic (PV) and, to a lesser extent, wind technologies. In the face of such challenges, E3 coupled its literature review with expert judgment based on experience working in the electric sector to best assess present-day technology costs.

### 2.2 Technology Cost Reductions

To provide meaningful inputs for WECC’s studies, E3 has also considered how the costs of generation resources may change in the future. Most of the generation resources included in the scope of E3’s analysis can be classified as mature technologies; for these resources, E3 has made a simplifying assumption that capital costs will remain stable in real terms over time. There are several
notable exceptions to this classification, however: wind, solar PV, and solar thermal technologies are all more appropriately described as emerging technologies, and most studies indicate that the capital costs of these resources will decline as the technologies mature.

To project future costs of these generation resources, E3 uses two primary approaches: (1) the application of historically-derived “learning curves” to estimate cost reductions as global experience grows; and (2) literature review of point projections of future technology costs. A brief description of each of these methods and the situations in which each one is applied in this study follows.

### 2.2.1 LEARNING CURVES

One method used to evaluate cost reduction potential of various generation technologies is the application of forward-looking learning curves. Learning curves describe a commonly observed empirical relationship between the cumulative experience in the production of a good or resource and the cost to produce it; namely, with increasing experience, costs tend to reduce as a result of increased efficiency and scale-up of manufacturing processes. This trend has been observed across a number of technologies and industries, but one of the clearest examples is the persistent reduction in the cost to produce photovoltaic modules that has accompanied the industry’s rapid growth over the past several decades. This effect is shown in Figure 3 (note the logarithmic scales).
Learning curves are most often expressed as the percentage reduction in cost that accompanies a doubling in cumulative production experience; this percentage metric is known as the learning rate. One natural result captured by this functional form is that the marginal impact of each unit of production on cost decreases as the technology matures. As a result, learning curves capture the well-documented trend that the costs of emerging technologies often drop rapidly as production scales up, whereas the costs of more mature technologies are more stable over time. This effect is summarized in Figure 4, which highlights the decreasing marginal impact of cumulative production experience on production cost.
Figure 4. Representative learning curve for an example learning rate. In this example, each doubling of cumulative experience results in a cost reduction of 20%.

In cases where E3 uses learning curves to predict future cost reductions, learning rates are determined on a technology-specific (or, in the case of solar PV, component-specific) basis through a review of literature on historically observed capital cost trends. Where a consensus learning rate has been established in literature, E3 has assumed this rate of progress will continue.

The other key parameter needed to establish a future learning curve for a specific technology is a forecast of global installed capacity. E3 acknowledges that there is a large amount of uncertainty in the choice of this parameter. E3 has relied predominantly on the International Energy Agency’s (IEA) Medium-Term Renewable Energy Market Report 2013 (IEA, 2013) as a credible source for...
such forecasts. To ensure the reasonableness of these forecasts, E3 has compared them to forecasts produced by industry associations such as the European Photovoltaic Industry Association (EPIA) and the Global Wind Energy Council (GWEC).

2.2.2 LITERATURE REVIEW

For nascent technologies with a very small installed global capacity whose commercialization is just beginning, it is not possible to rely on a learning rate that is well supported by the available literature. In these cases, E3 has adopted a more direct approach to forecasting cost reductions, relying on a survey of projected point estimates of future costs. E3 relies on the same types of sources used to evaluate present-day technology costs, including utility IRPs, engineering assessments of potential cost reductions, and consulting reports.

2.3 Regional Differences in Cost

The capital cost recommendations that E3 has developed are intended to represent the average cost of building new generation in the Western Interconnect; however, due to regional differences in the cost of labor and materials, plant construction costs will vary from state to state. To account for the regional differences in expected plant costs, E3 has developed state-specific multipliers for each technology for use in conjunction with the average cost estimates provided. The multipliers are derived from the cost indices in the US Army Corps Civil Works Construction Cost Indexing System (CWCCIS) (USACE, 2011).
2.4 Annualization of Resource Costs

Both WECC’s 10- and 20-year study cycles are “snapshot” analyses—that is, they evaluate the infrastructure requirements and operations of the grid during a single year in the future. To allow WECC to make use of the capital cost recommendations in its snapshot analyses, E3 has developed a set of Excel-based financial models that translate capital costs (as well as annual O&M and fuel costs for applicable technologies) into levelized annual costs. These financial models amortize the capital costs of the various technologies over their lifetimes to determine, on an annual basis, the magnitude of the costs that would be borne by ratepayers to fund a project’s construction. E3’s financial models include detailed cash flow models for project finance under ownership by an independent power producer (IPP), an investor-owned utility (IOU), and a tax-exempt publicly owned utility (POU); as well as a simple non-cash flow annualization calculation developed for implementation within the WECC LTPT. Further detail on these models can be found in Sections 5.1 and 5.2.
3 Capital Cost Recommendations

3.1 Coal Technologies

3.1.1 PULVERIZED COAL

3.1.1.1 Technology Description

Capital costs shown below are for a pulverized coal (PC) power plant without carbon capture and sequestration (CCS).

3.1.1.2 Present-day Cost

Table 2. Coal-fired steam generator capital and O&M costs.

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avista IRP</td>
<td>$3,683</td>
<td>$42</td>
</tr>
<tr>
<td>EIA</td>
<td>$3,683</td>
<td>$32</td>
</tr>
<tr>
<td>EPRI 2013A&lt;sup&gt;a&lt;/sup&gt;</td>
<td>$2,542</td>
<td>$64</td>
</tr>
<tr>
<td></td>
<td>$3,045</td>
<td>$64</td>
</tr>
<tr>
<td>Idaho Power IRP</td>
<td>$4,104</td>
<td>$27</td>
</tr>
<tr>
<td>Lazard</td>
<td>$3,060</td>
<td>$21</td>
</tr>
<tr>
<td>PacifiCorp IRP&lt;sup&gt;b&lt;/sup&gt;</td>
<td>$3,104</td>
<td>$42</td>
</tr>
<tr>
<td></td>
<td>$3,514</td>
<td>$39</td>
</tr>
<tr>
<td><strong>Recommendation</strong></td>
<td><strong>$3,700</strong></td>
<td><strong>$35</strong></td>
</tr>
</tbody>
</table>

<sup>a</sup> Cost ranges reflect a range of potential plant configurations and equipment types.
The range presented includes variation in plant size and location. Low estimate is a 600 MW plant at 4,500’ elevation (northern Utah). High estimate is a 790 MW plant at 6,500’ elevation (southwestern Wyoming).

3.1.2 INTEGRATED GASIFICATION COMBINED CYCLE WITH CARBON CAPTURE AND SEQUESTRATION

3.1.2.1 Technology Description

E3’s recommendation for coal-fired integrated gasification combined cycle plants with carbon capture and sequestration (“IGCC with CCS”) is higher than those surveyed since there are few existing plants that have been built and operated. Mississippi Power is currently constructing a 582 MW IGCC plant with 65% CO₂ capture, and the total projected cost is $5,018.6 million, which translates to $8,623/kW (Southern Company, 2014; MIT, 2013).

Additionally, there are both fixed and variable costs associated with CCS that are not captured in the surveys, including the CO₂ pipeline from the power plant to the geologic sequestration site, CO₂ transport costs, CO₂ injection costs, and long-term liability risks of storing CO₂ (together referred to as the costs of transport, storage, and monitoring, or TS&M). A NETL study focused on this subject produced estimates of TS&M costs that would increase plant capital costs by $150-$1,200 per kW and O&M costs by $1-6 per kW-year (the plant-specific costs vary based on the generator’s proximity to the sequestration site; the lower and upper values presented correspond to transport distances of 10 and 250 miles, respectively) (NETL, 2010).
3.1.2.2 Present-day Cost

Table 3. IGCC with CCS capital and O&M costs.

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost</th>
<th>Fixed O&amp;M</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>[$/kW]</td>
<td>[$/kW-yr]</td>
</tr>
<tr>
<td>Avista IRP</td>
<td>$7,342</td>
<td>$63</td>
</tr>
<tr>
<td>EIA</td>
<td>$8,612</td>
<td>$76</td>
</tr>
<tr>
<td>Lazard(^a)</td>
<td>$6,957</td>
<td>$29</td>
</tr>
<tr>
<td></td>
<td>$7,650</td>
<td>$29</td>
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<tr>
<td>PacifiCorp IRP(^b)</td>
<td>$5,434</td>
<td>$58</td>
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<tr>
<td></td>
<td>$6,152</td>
<td>$63</td>
</tr>
<tr>
<td>PGE IRP</td>
<td>$9,561</td>
<td>$67</td>
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<tr>
<td>Southern Company(^c)</td>
<td>$8,795</td>
<td></td>
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<tr>
<td><strong>Recommendation</strong></td>
<td><strong>$8,200</strong></td>
<td><strong>$65</strong></td>
</tr>
</tbody>
</table>

\(^a\) Low end estimate corresponds to current new IGCC capital costs. High end estimate corresponds to IGCC with 90% capture and excludes TS&M costs.

\(^b\) The range presented includes variation in plant size and location. Low estimate is a 466 MW plant at 4,500’ elevation (northern Utah). High estimate is a 456 MW plant at 6,500’ elevation (southwestern Wyoming).

\(^c\) Capital cost based on total project cost (2013 $ 5,018.6 million) filed by Mississippi Power in November 2013 and 582 MW plant capacity.

3.2 Gas Technologies

3.2.1 COMBINED HEAT AND POWER

3.2.1.1 Technology Description

E3 considered two options for new combined heat & power systems, small (up to 5 MW) and large (above 5 MW). Within these general classes, E3 has not attempted to distinguish between specific technology options, instead opting to offer generic capital costs that are representative of averages between the multiple technologies available for each size application. Small CHP is presumed
to be used primarily to meet on-site loads but may export to the grid if the relative thermal load is large enough; large CHP is presumed to be developed to export substantial amounts of electricity to the grid while serving a large thermal load.

### 3.2.1.2 Present-day Cost

**Table 4. Small CHP (<5 MW) capital and O&M costs.**

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>ICF(^a)</td>
<td>$5,104</td>
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</tr>
<tr>
<td></td>
<td>$5,930</td>
<td></td>
</tr>
<tr>
<td>ICF(^b)</td>
<td>$2,595</td>
<td></td>
</tr>
<tr>
<td>ICF(^c)</td>
<td>$3,071</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$3,283</td>
<td></td>
</tr>
<tr>
<td>ICF(^d)</td>
<td>$1,536</td>
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<tr>
<td></td>
<td>$2,912</td>
<td></td>
</tr>
<tr>
<td><strong>Recommendation</strong></td>
<td><strong>$3,800</strong></td>
<td><strong>$10.0</strong></td>
</tr>
</tbody>
</table>

\(^a\) Fuel cell (low and high costs capture variations in system size)

\(^b\) Gas turbine

\(^c\) Microturbine (low and high costs capture variations in system size)

\(^d\) Small reciprocating engine (low and high costs capture variations in system size)

**Table 5. Large CHP (>5 MW) capital and O&M costs.**

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>ICF(^a)</td>
<td>$1,239</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$1,610</td>
<td></td>
</tr>
<tr>
<td>ICF(^b)</td>
<td>$1,536</td>
<td></td>
</tr>
<tr>
<td><strong>Recommendation</strong></td>
<td><strong>$1,650</strong></td>
<td><strong>$10.0</strong></td>
</tr>
</tbody>
</table>

\(^a\) Gas turbine (low and high costs capture variations in system size)

\(^b\) Large reciprocating engine
3.2.2 COMBUSTION TURBINE

3.2.2.1 Technology Description

E3 offers two options for new gas-fired combustion turbines: aeroderivative and frame. Frame CTs, which include the GE 7FA, have long been considered the cheapest form of investment in new capacity. However, there is a tradeoff in performance, as these units typically have high heat rates and can generally operate economically during a very limited set of hours. Aeroderivative turbines, examples of which include the GE LM6000 and LMS100, are more advanced, offering a lower heat rate and more ramping flexibility at a higher capital cost. With the current concern regarding the need for flexibility to integrate intermittent renewable resources, a substantial portion of the expected investment in new gas-fired capacity in the WECC during the coming years will likely use aeroderivative technologies.
### 3.2.2.2 Present-day Cost

**Table 6. Aeroderivative combustion turbine capital and O&M costs.**

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avista IRP(^a)</td>
<td>$1,185</td>
<td>$14</td>
</tr>
<tr>
<td></td>
<td>$1,199</td>
<td>$16</td>
</tr>
<tr>
<td>CEC 2013(^b)</td>
<td>$1,174</td>
<td>$26</td>
</tr>
<tr>
<td></td>
<td>$1,510</td>
<td>$29</td>
</tr>
<tr>
<td>Idaho Power IRP(^c)</td>
<td>$1,212</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$1,369</td>
<td></td>
</tr>
<tr>
<td>PacifiCorp IRP(^d)</td>
<td>$1,041</td>
<td>$16</td>
</tr>
<tr>
<td></td>
<td>$1,271</td>
<td>$12</td>
</tr>
<tr>
<td>PGE IRP(^e)</td>
<td>$1,436</td>
<td>$13</td>
</tr>
<tr>
<td><strong>Recommendation</strong></td>
<td><strong>$1,200</strong></td>
<td><strong>$15</strong></td>
</tr>
</tbody>
</table>

\(^a\) Low estimate is a 100 MW Pratt FT8; high estimate is a 92 MW GE LMS 100.

\(^b\) Low estimate is a 200 MW aero CT; high estimate is a 50 MW aero CT.

\(^c\) Low estimate is a 47 MW aero CT; high estimate is a 100 MW aero CT.

\(^d\) Range captures variation in plant size and location. Low estimate is a 102 MW plant at 0’ elevation (ISO conditions; sea level and 59 degrees F). High estimate is a 144 MW plant at 4,250’ elevation.

\(^e\) CT corresponds to a 100 MW LMS100.

**Table 7. Frame combustion turbine capital and O&M costs.**

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>APS IRP</td>
<td>$769</td>
<td>$4</td>
</tr>
<tr>
<td>Avista IRP</td>
<td>$910</td>
<td>$12</td>
</tr>
<tr>
<td>EIA(^a)</td>
<td>$726</td>
<td>$7</td>
</tr>
<tr>
<td></td>
<td>$1,045</td>
<td>$8</td>
</tr>
<tr>
<td>Idaho Power IRP</td>
<td>$803</td>
<td></td>
</tr>
<tr>
<td>PacifiCorp IRP(^b)</td>
<td>$704</td>
<td>$8</td>
</tr>
<tr>
<td></td>
<td>$834</td>
<td>$10</td>
</tr>
<tr>
<td><strong>Recommendation</strong></td>
<td><strong>$825</strong></td>
<td><strong>$9</strong></td>
</tr>
</tbody>
</table>

\(^a\) Low estimate is a 210 MW F-class CT; high estimate is an 85 MW E-class CT.

\(^b\) Range captures variation in plant size and location. Low estimate is a 203 MW plant at 0’ elevation (ISO conditions; sea level and 59 degrees F). High estimate is a 172 MW plant at 6,500’ elevation.
3.2.3 COMBINED CYCLE GAS TURBINE

3.2.3.1 Technology Description

Combined cycle gas turbine (CCGT) technologies include both basic and advanced designs. Basic CCGTs typically utilize two F-class combustion turbines (CT) in conjunction with a steam turbine ("2x1 configuration"), whereas advanced CCGTs typically employ one G- or H-class CT in conjunction with a steam turbine ("1x1 configuration").

3.2.3.2 Present-day Cost

The capital and fixed O&M cost survey of basic and advanced CCGT designs are shown in Table 8 and Table 9, respectively. Each cost presented in this survey was judged to be reasonably representative of present-day technology. Cost estimates are separated between wet- and dry-cooled designs,\(^1\) the presentation of which provides the basis for a distinction in the cost estimates between the two technologies.

---

\(^1\) If a source did not indicate whether the plant was wet- or dry-cooled, E3 assumed it would use wet cooling.
Table 8. Basic combined cycle capital and O&M costs.

<table>
<thead>
<tr>
<th>Source</th>
<th>Wet Cooled</th>
<th></th>
<th>Dry Cooled</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Capital Cost</td>
<td>Fixed O&amp;M</td>
<td>Capital Cost</td>
<td>Fixed O&amp;M</td>
</tr>
<tr>
<td></td>
<td>[$/kW]</td>
<td>[$/kW-yr]</td>
<td>[$/kW]</td>
<td>[$/kW-yr]</td>
</tr>
<tr>
<td>APS IRP</td>
<td>$884</td>
<td>$5</td>
<td>$988</td>
<td>$5</td>
</tr>
<tr>
<td>CEC 2013</td>
<td></td>
<td></td>
<td>$1,185</td>
<td>$35</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$1,209</td>
<td>$35</td>
</tr>
<tr>
<td>EIA</td>
<td>$1,016</td>
<td>$14</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Idaho Power IRP</td>
<td>$1,262</td>
<td></td>
<td>$1,364</td>
<td></td>
</tr>
<tr>
<td>Lazard</td>
<td>$1,026</td>
<td>$6</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$1,344</td>
<td>$6</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PacifiCorp IRP</td>
<td>$1,145</td>
<td>$9</td>
<td>$1,202</td>
<td>$7</td>
</tr>
<tr>
<td>PGE IRP</td>
<td>$1,363</td>
<td>$7</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Xcel IRP</td>
<td>$785</td>
<td>$8</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$1,251</td>
<td>$12</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Recommendation</td>
<td>$1,125</td>
<td>$10</td>
<td>$1,200</td>
<td>$10</td>
</tr>
</tbody>
</table>

Table 9. Advanced combined cycle capital and O&M costs.

<table>
<thead>
<tr>
<th>Source</th>
<th>Wet Cooled</th>
<th></th>
<th>Dry Cooled</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Capital Cost</td>
<td>Fixed O&amp;M</td>
<td>Capital Cost</td>
<td>Fixed O&amp;M</td>
</tr>
<tr>
<td></td>
<td>[$/kW]</td>
<td>[$/kW-yr]</td>
<td>[$/kW]</td>
<td>[$/kW-yr]</td>
</tr>
<tr>
<td>Avista IRP</td>
<td></td>
<td></td>
<td>$1,279</td>
<td>$22</td>
</tr>
<tr>
<td>CEC 2013</td>
<td></td>
<td></td>
<td>$1,232</td>
<td>$35</td>
</tr>
<tr>
<td>EIA</td>
<td>$1,134</td>
<td>$16</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PacifiCorp IRP</td>
<td></td>
<td></td>
<td>$966</td>
<td>$10</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$1,202</td>
<td>$7</td>
</tr>
<tr>
<td>Recommendation</td>
<td>$1,225</td>
<td>$10</td>
<td>$1,300</td>
<td>$10</td>
</tr>
</tbody>
</table>
3.2.4 RECIPROCATING ENGINES

Reciprocating engines, which include the Wärtsilä 8V50SG, are an alternative gas-fired power generation technology for both peaking and flexibility applications. In recent years, a number of utilities have used reciprocating engines as a substitute for new aeroderivate CTs due to their operational flexibility and ability to maintain a low heat rate at partial load. In response to stakeholder interest, E3 has surveyed costs for new reciprocating engines. Public data suggests a capital cost slightly higher than aeroderivative CTs, though anecdotal evidence shows they are competitive.

Table 10. Reciprocating engine capital and O&M costs.

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avista IRP</td>
<td>$1,141</td>
<td>$19</td>
</tr>
<tr>
<td>PacifiCorp IRP</td>
<td>$1,249</td>
<td>$16</td>
</tr>
<tr>
<td>Pacifica IRP</td>
<td>$1,524</td>
<td>$20</td>
</tr>
<tr>
<td>PGE IRP</td>
<td>$1,769</td>
<td>$16</td>
</tr>
<tr>
<td>Recommendation</td>
<td>$1,300</td>
<td>$18</td>
</tr>
</tbody>
</table>
3.3 Other Conventional Technologies

3.3.1 NUCLEAR

3.3.1.1 Technology Description

Nuclear plant costs differ based on the reactor design, but most sources surveyed employed an AP1000 reactor. The cost of decommissioning for a nuclear power plant is included in fixed O&M since most utilities recover this cost through a sinking fund. E3’s recommended fixed O&M for nuclear plants appears lower than many of the sources, but this is mainly a result of accounting, as WECC uses a higher variable O&M for nuclear plants ($5.30/MWh) than many of these sources. Accordingly, E3’s recommended “consolidated O&M” (total O&M cost per unit of generation) is of comparable magnitude to most of the sources surveyed.

3.3.1.2 Present-day Cost

Table 11. Nuclear capital and O&M costs.

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avista IRP</td>
<td>$9,125</td>
<td>$94</td>
</tr>
<tr>
<td>EIA</td>
<td>$8,689</td>
<td>$97</td>
</tr>
<tr>
<td>EPRI 2013A²</td>
<td>$5,692</td>
<td>$117</td>
</tr>
<tr>
<td></td>
<td>$6,380</td>
<td>$117</td>
</tr>
<tr>
<td>Idaho Power IRP</td>
<td>$10,971</td>
<td>$146</td>
</tr>
<tr>
<td>Lazardb</td>
<td>$5,493</td>
<td>$61</td>
</tr>
<tr>
<td></td>
<td>$8,913</td>
<td>$61</td>
</tr>
<tr>
<td>PacifiCorp IRP</td>
<td>$7,358</td>
<td>$92</td>
</tr>
<tr>
<td>Recommendation</td>
<td>$8,000</td>
<td>$85</td>
</tr>
</tbody>
</table>
3.3.2 LARGE HYDRO

3.3.2.1 Technology Description

Large (or conventional) hydro is considered a mature technology—indeed, it was deployed so widely in the West between 1940 and 1975 that dams already stand on many of the most favorable sites. Nonetheless, a recommendation is derived from the sources that did provide estimates of the cost of constructing a new large hydro facility.

3.3.2.2 Present-Day Costs

Table 12. Large hydro capital and O&M costs.

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>B&amp;V/NREL</td>
<td>$4,196</td>
<td>$17</td>
</tr>
<tr>
<td>CPUC (LTPP)</td>
<td>$3,669</td>
<td>$33</td>
</tr>
<tr>
<td>EIA</td>
<td>$3,289</td>
<td>$15</td>
</tr>
<tr>
<td>WREZ 3.0 (B&amp;V)</td>
<td>$687</td>
<td>$7</td>
</tr>
<tr>
<td></td>
<td>$57,457</td>
<td>$1087</td>
</tr>
<tr>
<td></td>
<td>$7,529</td>
<td>$136</td>
</tr>
</tbody>
</table>

**Recommendation**

$3,200 $30

---

a Low estimate is an 1,000 MW plant in BC_EA; high estimate is a 375 MW plant in BC_NW; third estimate contains the capacity-weighted average cost and performance data of potential large hydro (>30 MW) plants across the WECC.

b Range presented reflects uncertainty in nuclear costs. Excludes decommissioning costs.
3.4 Renewable Technologies

3.4.1 BIOGAS

3.4.1.1 Technology Description

E3 offers two biogas technology options: (1) landfill gas energy recovery plants which combust methane captured from landfills; and (2) other plants which capture gas from sources besides landfills, such as waste water treatment facilities and animal waste.

3.4.1.2 Present-day Cost

Table 13. Landfill biogas capital and O&M costs.

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>APS IRP</td>
<td>$1,723</td>
<td>$61</td>
</tr>
<tr>
<td>Avista IRP</td>
<td>$2,654</td>
<td>$27</td>
</tr>
<tr>
<td>Idaho Power IRP</td>
<td>$4,729</td>
<td>-</td>
</tr>
<tr>
<td>CPUC</td>
<td>$3,003</td>
<td>$142</td>
</tr>
<tr>
<td>EIA</td>
<td>$8,987</td>
<td>$369</td>
</tr>
<tr>
<td>NWPCCC</td>
<td>$2,940</td>
<td>$31</td>
</tr>
<tr>
<td>WEC/WEC/NWPCCC</td>
<td>$1,571</td>
<td>$92</td>
</tr>
<tr>
<td>Recommendation</td>
<td>$2,800</td>
<td>$100</td>
</tr>
</tbody>
</table>
Table 14. Biogas (other) capital and O&M costs.

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avista IRP</td>
<td>$4,721</td>
<td>$47.0</td>
</tr>
<tr>
<td>CPUC</td>
<td>$6,006</td>
<td>$180.2</td>
</tr>
<tr>
<td>NWPPCC(^a)</td>
<td>$6,256</td>
<td>$30.7</td>
</tr>
<tr>
<td>Recommendation</td>
<td>$5,600</td>
<td>$120</td>
</tr>
</tbody>
</table>

\(^a\) Animal manure and waste water treatment energy recovery technologies

3.4.2 BIOMASS

3.4.2.1 Technology Description

The biomass technology represented in this update refers to a conventional steam electric plant using biomass as a fuel.

3.4.2.2 Present-day Cost

Table 15. Biomass capital and O&M costs.

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avista IRP</td>
<td>$4,436</td>
<td>$187.8</td>
</tr>
<tr>
<td>CEC 2013</td>
<td>$5,357</td>
<td>$108.4</td>
</tr>
<tr>
<td>EIA</td>
<td>$4,520</td>
<td>$10.96</td>
</tr>
<tr>
<td>EPRI 2013A</td>
<td>$4,395</td>
<td>$68.8</td>
</tr>
<tr>
<td></td>
<td>$5,560</td>
<td>$68.8</td>
</tr>
<tr>
<td>Lazard</td>
<td>$3,060</td>
<td>$96.9</td>
</tr>
<tr>
<td></td>
<td>$4,080</td>
<td>$96.9</td>
</tr>
<tr>
<td>PacifiCorp IRP</td>
<td>$3,458</td>
<td>$42.2</td>
</tr>
<tr>
<td>PGE IRP</td>
<td>$8,169</td>
<td>$228.2</td>
</tr>
<tr>
<td>WREZ 3.0 (B&amp;V)(^a)</td>
<td>$3,765</td>
<td>$187.7</td>
</tr>
</tbody>
</table>

\(^a\) Animal manure and waste water treatment energy recovery technologies
3.4.3 GEOTHERMAL

3.4.3.1 Technology Description

E3 has surveyed two options for new geothermal plants: conventional hydrothermal and enhanced geothermal systems (EGS). Conventional hydrothermal applications of geothermal comprise both binary and flash cycles; E3 recommends a single cost that is intended to be applicable to both, as the site-specific uncertainties in cost are far larger than the difference between the two technologies.

EGS is an emerging technology that could substantially increase the potential for geothermal generation in the West. Unlike conventional geothermal applications, which rely on naturally occurring circulation of heat near the earth’s surface, EGS injects fluids deep into artificial fractures to capture heat from within the earth (Augustine, 2011).

3.4.3.2 Present-Day Cost

Despite the technology’s maturity, cost estimates for conventional geothermal technologies range considerably—in large part due to the very site-specific nature of the technology. The quality of a geothermal resource, its depth, and
the geologic attributes of the site can all have significant impacts on its cost of development. As with other technologies, E3’s recommended cost for conventional geothermal is chosen to represent a median estimate.

Table 16. Conventional hydrothermal capital and O&M costs.

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avista IRP</td>
<td>$4,767</td>
<td>$182.6</td>
</tr>
<tr>
<td>B&amp;V/NREL(^a)</td>
<td>$7,347</td>
<td>$256.3</td>
</tr>
<tr>
<td>CEC 2013(^b)</td>
<td>$7,085</td>
<td>$91.6</td>
</tr>
<tr>
<td></td>
<td>$7,778</td>
<td>$91.6</td>
</tr>
<tr>
<td>EIA3(^c)</td>
<td>$5,041</td>
<td>$103.7</td>
</tr>
<tr>
<td></td>
<td>$7,214</td>
<td>$136.9</td>
</tr>
<tr>
<td>EPRI 2013A</td>
<td>$5,666</td>
<td>$74.1</td>
</tr>
<tr>
<td></td>
<td>$9,822</td>
<td>$85.8</td>
</tr>
<tr>
<td>Lazard(^d)</td>
<td>$4,692</td>
<td>$241.3</td>
</tr>
<tr>
<td></td>
<td>$7,395</td>
<td>$285.9</td>
</tr>
<tr>
<td>PacifiCorp IRP(^e)</td>
<td>$4,974</td>
<td>$122.9</td>
</tr>
<tr>
<td></td>
<td>$6,137</td>
<td>$194.9</td>
</tr>
<tr>
<td>PGE IRP</td>
<td>$10,123</td>
<td>$212.7</td>
</tr>
<tr>
<td>WREZ 3.0 (B&amp;V)(^f)</td>
<td>$4,415</td>
<td>$217.8</td>
</tr>
<tr>
<td></td>
<td>$14,356</td>
<td>$296.9</td>
</tr>
<tr>
<td></td>
<td>$5,759</td>
<td>$269.8</td>
</tr>
<tr>
<td>Recommendation</td>
<td>$5,900</td>
<td>$120.0</td>
</tr>
</tbody>
</table>

\(^a\) Fixed O&M estimate based on variable O&M cost of $34.4/MWh and 85% capacity factor.
\(^b\) Low estimate utilizes binary technology; high estimate utilizes flash technology.
\(^c\) Low estimate utilizes binary technology; high estimate utilizes dual flash technology.
\(^d\) Low fixed O&M estimate is based on variable O&M cost of $30.6/MWh and 90% capacity factor; high fixed O&M estimate is based on variable O&M cost of $40.8/MWh and 80% capacity factor.
\(^e\) Low estimate is a 35 MW geothermal plant with dual flash technology; high estimate is a 43 MW geothermal plant with binary technology.
\(^f\) Low estimate is an 81 MW geothermal plant in UT; high estimate is a 12 MW geothermal plant in NV; third estimate contains the capacity-weighted average cost and performance data of potential geothermal plants across the WECC. Fixed O&M is estimated from variable O&M costs assuming capacity factors of 90%, 80% and 84.3%, respectively.
Estimates for the costs of EGS are much sparser, reflecting its emerging nature (at this point, a limited number demonstration projects have been successfully installed in the West). E3’s recommendation, shown in Table 17, reflects the technology’s nascent nature.

Table 17. Enhanced geothermal capital and O&M costs.

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alta Rock</td>
<td>$3,604</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$10,047</td>
<td></td>
</tr>
<tr>
<td>B&amp;V/NREL(^a)</td>
<td>$12,246</td>
<td>$256</td>
</tr>
<tr>
<td>EPRI 2010</td>
<td>$3,319</td>
<td></td>
</tr>
<tr>
<td></td>
<td>$9,845</td>
<td></td>
</tr>
<tr>
<td>NREL 2011(^b)</td>
<td>$5,453</td>
<td>$410</td>
</tr>
<tr>
<td></td>
<td>$17,069</td>
<td>$1,454</td>
</tr>
<tr>
<td>Recommendation</td>
<td>$10,000</td>
<td>$400</td>
</tr>
</tbody>
</table>

\(^a\) Fixed O&M estimate based on variable O&M cost of $34.4/MWh and 85% capacity factor.
\(^b\) Low estimate is a 20 MW plant utilizing flash technology at a reservoir depth of 1.0 km and reservoir temperature of 300 degrees C; high estimate is a 20 MW plant utilizing binary technology at a reservoir depth of 3.0 km and a reservoir temperature of 150 degrees C.

3.4.4 SMALL HYDROELECTRIC

3.4.4.1 Technology Description

For the purposes of this review, small hydroelectric facilities are assumed to be run-of-river facilities of a size smaller than 30 MW. The distinction between this technology and large (conventional) hydro, shown in Section 3.3.2, is drawn not only because of the expected differences in cost, but also because many WECC states’ Renewable Portfolio Standards allow generation from small hydro
facilities to count towards compliance obligations whereas generation from large hydro plants is excluded.

### 3.4.4.2 Present-Day Cost

Table 18. Small hydro capital and O&M costs.

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>CEC 2009</td>
<td>$2,159</td>
<td>$20</td>
</tr>
<tr>
<td>CPUC (LTPP)</td>
<td>$4,324</td>
<td>$33</td>
</tr>
<tr>
<td>NWPCC</td>
<td>$3,707</td>
<td>$106</td>
</tr>
<tr>
<td>Idaho Power IRP</td>
<td>$4,798</td>
<td>$15</td>
</tr>
<tr>
<td>WREZ 3.0 (B&amp;V)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$3,070</td>
<td>$24</td>
</tr>
<tr>
<td></td>
<td>$13,809</td>
<td>$361</td>
</tr>
<tr>
<td></td>
<td>$6,857</td>
<td>$178</td>
</tr>
<tr>
<td>Recommendation</td>
<td>$4,000</td>
<td>$30</td>
</tr>
</tbody>
</table>

* Low estimate is an 8 MW plant in ID_SW; high estimate is a 26 MW geothermal plant in BC_WE; third estimate contains the capacity-weighted average cost and performance data of potential small hydro (<30 MW) plants across the WECC.

### 3.4.5 SOLAR PV

#### 3.4.5.1 Technology Description

Costs of new solar PV systems have been changing rapidly from year to year due to the technology’s continued maturation. Reductions in factory gate module prices (see Figure 3) and lower balance-of-system costs have led to recent drops in costs for all system types, from central station plants developed under utility contract to residential rooftop systems financed by homeowners. Figure 5, which shows actual installed residential system costs in Arizona, California and Nevada, highlights the persistence of long-term cost reductions through 2013.
Figure 5. Average capital costs for residential PV systems installed under the California Solar Initiative (CSI) and in the Arizona Public Service (APS) and NV Energy territories


With such a rapidly evolving technology, there is a natural challenge identifying today’s capital costs; published cost figures and estimates quickly become outdated, while projected costs are speculative and span a wide range. Accepting that the lag in reported costs and the uncertainty in future costs can obscure today’s true costs, the cost estimates provided herein represent E3’s best understanding of current solar PV costs at the time this survey was completed.

Identifying present-day costs for solar PV is also challenging because of the duality of conventions used to report costs. The capacity of a solar PV facility can be measured in two different ways: (1) based on the nameplate rating of the modules that make up the plant (“DC capacity”), or (2) based on the
nameplate rating of the inverter that connects those modules to the grid ("AC capacity"). The ratio between these two numbers is the "inverter loading ratio" and reflects a system design choice that must be made by the developer with consideration for economics and available land area. Expressing a capital cost on either basis is equally valid; however, care must be given to ensure that a uniform convention is used throughout the application of the numbers. For the purposes of this study, E3 develops its cost estimates on the basis of a plant’s DC capacity and then translates them into AC capacity by multiplying by the assumed inverter loading ratio.

The continued reductions in solar PV costs have been accompanied by substantial interest in development at all scales. To allow WECC to study the tradeoffs between various PV system types, E3 has developed capital cost estimates for six different representative systems: residential rooftop and commercial rooftop, distributed utility-scale (fixed tilt and single-axis tracking), and central station utility-scale (fixed tilt and single-axis tracking).

3.4.5.2 Present-Day Cost

The transient nature of solar PV costs adds a layer of complexity to this analysis, as each source’s cost estimate is tied to the state of the technology at a particular point in time. For each source surveyed, costs for solar PV are shown explicitly according to the year in which the plant came online (or was assumed to be constructed) in order to provide a clear reference for the pace at which costs have declined. Capital costs shown for solar PV technologies in Table 19 through Table 22 are expressed relative to the system’s DC nameplate rating.
Table 19. Residential rooftop solar PV capital and O&M costs.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2010</td>
<td>2011</td>
</tr>
<tr>
<td>Arizona Goes Solar (APS)</td>
<td>$6.60</td>
<td>$6.15</td>
</tr>
<tr>
<td>California Solar Initiative</td>
<td>$7.91</td>
<td>$7.30</td>
</tr>
<tr>
<td>LBNL (TTS)</td>
<td>$7.23</td>
<td>$6.42</td>
</tr>
<tr>
<td>NVEnergy Rebate Program</td>
<td>$6.83</td>
<td>$5.75</td>
</tr>
<tr>
<td>NREL 2012</td>
<td>$6.24</td>
<td>$4.65</td>
</tr>
<tr>
<td>SEIA/GTM</td>
<td>$7.34</td>
<td>$6.80</td>
</tr>
<tr>
<td>SPV Market Research</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Recommendation</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 20. Commercial rooftop solar PV capital and O&M costs

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2010</td>
<td>2011</td>
</tr>
<tr>
<td>Arizona Goes Solar (APS)</td>
<td>$9.68</td>
<td>$5.73</td>
</tr>
<tr>
<td>California Solar Initiative</td>
<td>$5.93</td>
<td>$5.90</td>
</tr>
<tr>
<td>LBNL (TTS)</td>
<td>$5.98</td>
<td>$5.11</td>
</tr>
<tr>
<td>SEIA/GTM</td>
<td>$6.55</td>
<td>$5.51</td>
</tr>
<tr>
<td>SPV Market Research</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Recommendation</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Table 21. Utility scale solar PV (fixed tilt) capital and O&M costs.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2010</td>
<td>2011</td>
</tr>
<tr>
<td>CEC 2013(^a)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CPUC</td>
<td>$3.15</td>
<td>$2.60</td>
</tr>
<tr>
<td>LBNL (TTS)(^b)</td>
<td>$4.85</td>
<td>$3.73</td>
</tr>
<tr>
<td></td>
<td>$3.27</td>
<td>$3.42</td>
</tr>
<tr>
<td>SEIA/GTM</td>
<td>$5.13</td>
<td>$3.97</td>
</tr>
<tr>
<td>WREZ 3.0 (B&amp;V)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Recommendation (&lt;20 MW)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Recommendation (&gt;20 MW)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

\(^a\) Low estimate is a 100 MW plant; high estimate is a 20 MW plant.
\(^b\) Low estimate utilizes thin film technology; high estimate utilizes crystalline technology.
\(^c\) Low estimate is a 50 MW-ac poly-si fixed tilt plant; high estimate is a 2 MW-ac thin film plant.

Table 22. Utility scale solar PV (single axis tracking) capital and O&M costs.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2010</td>
<td>2011</td>
</tr>
<tr>
<td>CEC 2013(^a)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LBNL (TTS)</td>
<td>$5.76</td>
<td>$3.80</td>
</tr>
<tr>
<td>SEIA/GTM</td>
<td>$5.13</td>
<td>$3.97</td>
</tr>
<tr>
<td>WREZ 3.0 (B&amp;V)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Recommendation (&lt;20 MW)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Recommendation (&gt;20 MW)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

\(^a\) Low estimate is a 100 MW plant; high estimate is a 20 MW plant.

The DC capital costs presented in the table above are multiplied by an assumed inverter loading ratio to calculate the AC capital costs. To ensure alignment between resource costs and performance in the transmission planning studies,
E3 uses the same inverter loading ratios that were used in the development of WECC’s PV production profiles:

- Fixed tilt, utility: 1.40
- Tracking, utility: 1.30
- Rooftop: 1.20

The assumed DC capital costs and resulting AC capital costs are shown in Table 23.

Table 23. Summary of capital costs and inverter loading ratio assumptions

<table>
<thead>
<tr>
<th>Source</th>
<th>DC Capital Cost [$/kW-dc]</th>
<th>Inverter Loading Ratio</th>
<th>AC Capital Cost [$/kW-ac]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential Rooftop</td>
<td>$4,400</td>
<td>1.20</td>
<td>$5,280</td>
</tr>
<tr>
<td>Commercial Rooftop</td>
<td>$3,800</td>
<td>1.20</td>
<td>$4,560</td>
</tr>
<tr>
<td>Fixed Tilt (1-20 MW)</td>
<td>$2,600</td>
<td>1.40</td>
<td>$3,640</td>
</tr>
<tr>
<td>Tracking (1-20 MW)</td>
<td>$3,000</td>
<td>1.30</td>
<td>$3,900</td>
</tr>
<tr>
<td>Fixed Tilt (&gt; 20 MW)</td>
<td>$2,200</td>
<td>1.40</td>
<td>$3,080</td>
</tr>
<tr>
<td>Tracking (&gt; 20 MW)</td>
<td>$2,600</td>
<td>1.30</td>
<td>$3,380</td>
</tr>
</tbody>
</table>

3.4.5.3 Market Benchmark

While publicly reported capital cost estimates serve as the basis of E3’s development of recommendations, market data on the prices at which utilities have signed power purchase agreements with developers provide a second important reference point against which the cost recommendations can be compared. California is currently the most active market for utility procurement of solar PV in the Western United States; over the past several years, the three
major investor-owned utilities have signed contracts totaling several thousand megawatts of solar PV. While the prices of individual contracts are not released to the public, the California Public Utilities Commission (CPUC) publishes quarterly reports to the California legislature that frequently summarize the prices of successful bids; recently released reports suggest that recent successful solar PV bids have ranged between $80-90/MWh.

In order to draw this comparison, E3 has used its cost recommendations and its pro-forma financing model to calculate a benchmark PPA for a resource based on characteristics and financing terms that are chosen with the intent to mimic resources purchased by utilities. The assumptions used in this benchmarking exercise, as well as the resulting calculated PPA price, are summarized in Table 24.

Table 24. Benchmark PPA price for utility-scale fixed tilt solar PV plant installed in 2013 in California.

<table>
<thead>
<tr>
<th>Item</th>
<th>Units</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost</td>
<td>$/W-ac</td>
<td>$3.08</td>
</tr>
<tr>
<td>Fixed O&amp;M</td>
<td>$/kW-yr</td>
<td>$25</td>
</tr>
<tr>
<td>Capacity Factor</td>
<td>% (ac)</td>
<td>28%</td>
</tr>
<tr>
<td>Property Tax&lt;sup&gt;a&lt;/sup&gt;</td>
<td>%/yr</td>
<td>0%</td>
</tr>
<tr>
<td>MACRS</td>
<td>yrs</td>
<td>5 + bonus</td>
</tr>
<tr>
<td>After-tax WACC</td>
<td>%</td>
<td>7.5%</td>
</tr>
<tr>
<td>Investment Tax Credit</td>
<td>%</td>
<td>30%</td>
</tr>
<tr>
<td>PPA Term</td>
<td>yrs</td>
<td>25</td>
</tr>
<tr>
<td><strong>Calculated PPA Price</strong></td>
<td>$/MWh</td>
<td><strong>$88</strong></td>
</tr>
</tbody>
</table>

<sup>a</sup> No property tax is assessed as solar technologies installed in California before 2017 are currently exempt.
3.4.5.4  *Projection of Cost Reductions*

The cost of solar photovoltaic installations is expected to continue its long-term downward trend. Reductions in capital costs may be achieved through a number of pathways including both hardware ("hard") costs and the remaining balance of system costs. To capture the different cost reduction opportunities, E3 has broken capital costs out into three categories for each segment of solar PV (i.e. residential, commercial, and small/large utility scale):

- **Module costs**: direct cost of photovoltaic modules
- **Non-module “hard” costs**: costs of inverter, racking, electrical equipment, etc.
- **“Soft costs”**: labor, permitting fees, etc.

To project the plausible magnitude of these future cost reductions, E3 develops learning curves for both PV modules and other “hard” and “soft” non-module balance-of-systems (BOS) components of the installation.

Historically, module prices have followed a learning rate of 20% over the long term. This learning rate has been confirmed in many studies over varying time horizons. However, module prices are currently below this long-term learning curve due to a variety of reasons such as current supply/demand imbalances, temporary price declines in silicon, and other idiosyncratic factors. E3 recommends keeping the current observed module price constant in real terms until the long term learning curve “catches up” to it to reflect the lowered potential for cost reductions in the near to medium term. E3 believes this is reasonable, especially for a longer term forecast and anecdotal evidence such as module price forecasts support that prices will remain flat in the near to
medium term. Figure 6 shows how our methodology approaches the long-term trend as global installed capacity increases, and

Figure 7 displays the impact on projected module prices through 2034.

**Figure 6. Solar PV module cost learning curve.**

**Figure 7. Historic and projected solar PV module prices based on observed learning curve.**
For a forecast of global installed capacity to use when calculating learning curves, E3 relies on the IEA’s Medium-Term Renewable Energy Market Report 2013, which forecasts global installed capacity from 2013 through 2018. E3 extrapolates this forecast through 2034 assuming a continued rate of installations based on the change in global installed capacity over the original forecast period (2013-2018). The resulting forecast is shown below.

**Figure 8. Forecast of global installed solar PV capacity used to evaluate PV cost reductions through application of learning curves.**

There has been considerably less focus on historical learning rates for balance-of-system or non-module components. The range of estimates is considerably larger: IEA has had learning rates of 18% for BOS, whereas a recent LBNL study found that BOS costs for systems installed between 2001 and 2012 in the U.S. followed a learning rate of 7% while in Germany the historical BOS learning rate has been 15% (Seel, 2013). While there are substantial opportunities to reduce non-module BOS costs through expedited permitting and installation processes, these costs may not naturally decline along the same learning curve as module-related costs. Additionally, some of these BOS cost savings have already
occurred in the utility scale segments given the incentives and cost/benefits of said savings in those segments.

E3 recommends a lower learning rate for utility scale projects of 10% and a higher learning rate for rooftop (i.e. residential and commercial) projects of 15% for non-module BOS-related costs. This reflects the fact that there is no strong evidence that utility-scale PV should deviate from a 10% rate, while there has been substantial recent effort to identify cost reduction potential in rooftop PV systems. At the same time, reported costs of rooftop systems are influenced by the retail rate structures that enable their viability as fair market value of PV exceeds actual system costs. Because of these factors, E3 has applied a slightly higher learning rate (15%) for non-module costs of rooftop systems.

Figure 9. Projected non-module cost reductions for solar PV based on learning curves.

To combine the three learning curves—one for module-related costs and the other two for non-module “soft” and “hard” BOS components—E3 has had to
make assumptions on the proportion of today’s installed system costs that can be attributed to each. Based on several recent studies published by NREL and LBNL, E3 estimates the magnitude of each of these cost categories by solar PV segment. The figure below graphically breaks down these categories on a percentage basis. E3’s capital cost recommendations can also be seen in this figure.

**Figure 10. Estimated breakdown of module and non-module “soft” and “hard” costs by solar PV segment.**

Weighting the three individual learning curves by these fractions, the module- and non-module BOS-related cost projections are joined to create a single projection of system costs over the next two decades, as shown below. The approach described above results in a 22% reduction in rooftop solar PV capital costs relative to 2013 levels by 2022, and a 33% reduction by 2032 versus 14% and 23% reductions, respectively, for utility scale solar PV. See the figure below.
for a depiction of the estimated cost reductions over time for each solar PV segment.

Figure 11. E3 long-term cost projections by solar PV segment.

3.4.6 SOLAR THERMAL

3.4.6.1 Technology Description

In the development of cost estimates for solar thermal, E3 considered two technologies:

+ **Parabolic trough**: mirrors focus solar energy on a heat transfer fluid (HTF; commonly a synthetic oil) carried in axial tubes; the heated working fluid is used to create steam that powers a traditional steam generator.

+ **Power tower**: a field of tracking mirrors (“heliostats”) focus energy on a tower to heat a working fluid and power a steam generator.
While the majority of systems currently installed rely on trough technologies, there is growing commercial interest in the development of tower alternatives. Because the LTPT does not have sufficient resolution to meaningfully distinguish between the two technologies, and because current data suggests similar cost and performance characteristics for the two at present, E3 recommends developing a single, representative technology that considers the cost, performance, and expected market shares of the two competing options. Accordingly, E3’s estimate of today’s capital costs is based largely on publicly available costs for trough systems—with its limited commercialization, the public literature on current tower troughs is sparse. However, in the development of future solar thermal cost estimates, E3 considers both the technical cost reduction potential for trough systems as well as the possibility that tower technologies may enter the market at substantially reduced costs in the future.
### 3.4.6.2 Present-day Cost

**Table 25. Solar thermal without storage capital and O&M costs.**

<table>
<thead>
<tr>
<th>Source</th>
<th>Type</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>WEC/BNEF</td>
<td>Trough</td>
<td>$3,488</td>
<td>$65</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$7,823</td>
<td>$61</td>
</tr>
<tr>
<td></td>
<td>Tower</td>
<td>$4,162</td>
<td>$70</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$6,242</td>
<td>$66</td>
</tr>
<tr>
<td>CEC 2013</td>
<td>Trough</td>
<td>$4,497</td>
<td>$72</td>
</tr>
<tr>
<td></td>
<td>Tower</td>
<td>$4,910</td>
<td>$64</td>
</tr>
<tr>
<td>EIA</td>
<td></td>
<td>$5,497</td>
<td>$70</td>
</tr>
<tr>
<td>EPRI 2013A</td>
<td>Trough</td>
<td>$4,289</td>
<td>$68</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$7,995</td>
<td>$72</td>
</tr>
<tr>
<td>Idaho Power IRP</td>
<td></td>
<td>$6,493</td>
<td>$57</td>
</tr>
<tr>
<td>IRENA 2013</td>
<td>Trough</td>
<td>$4,772</td>
<td>??</td>
</tr>
<tr>
<td>Lazard</td>
<td>Tower</td>
<td>$5,712</td>
<td>$51</td>
</tr>
<tr>
<td>PacifiCorp IRP</td>
<td>Tower</td>
<td>$5,011</td>
<td>$66</td>
</tr>
<tr>
<td>WREZ 3.0 (B&amp;V)²</td>
<td></td>
<td>$5,814</td>
<td>$67</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$6,018</td>
<td>$67</td>
</tr>
<tr>
<td>Recommendation</td>
<td></td>
<td>$5,500</td>
<td>$60</td>
</tr>
</tbody>
</table>

* Low estimate utilizes wet cooling; high estimate utilizes dry cooling.
Table 26. Solar thermal with storage capital and O&M costs.

<table>
<thead>
<tr>
<th>Source</th>
<th>Type</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>WEC/BNEF</td>
<td>Trough</td>
<td>$6,120</td>
<td>$72</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$8,833</td>
<td>$120</td>
</tr>
<tr>
<td></td>
<td>Tower</td>
<td>$6,120</td>
<td>$63</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$11,179</td>
<td>$65</td>
</tr>
<tr>
<td>CEC 2013a</td>
<td>Trough</td>
<td>$6,454</td>
<td>$72</td>
</tr>
<tr>
<td></td>
<td>Tower</td>
<td>$6,891</td>
<td>$68</td>
</tr>
<tr>
<td></td>
<td>Tower</td>
<td>$7,669</td>
<td>$68</td>
</tr>
<tr>
<td>Idaho Power IRP</td>
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<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>$9,331</td>
<td></td>
</tr>
<tr>
<td>IRENA 2013b</td>
<td>Trough</td>
<td>$8,765</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Tower</td>
<td>$8,714</td>
<td></td>
</tr>
<tr>
<td>Lazardc</td>
<td>Tower</td>
<td>$9,180</td>
<td>$82</td>
</tr>
<tr>
<td>PacifiCorp IRP</td>
<td>Tower</td>
<td>$6,012</td>
<td>$66</td>
</tr>
<tr>
<td>WREZ 3.0 (B&amp;V)d</td>
<td></td>
<td>$7,956</td>
<td>$67</td>
</tr>
<tr>
<td></td>
<td></td>
<td>$8,262</td>
<td>$67</td>
</tr>
<tr>
<td>Recommendation</td>
<td></td>
<td>$8,000</td>
<td>$60</td>
</tr>
</tbody>
</table>

- Low CSP tower estimate includes six hours storage; high CSP tower estimate includes eleven hours storage.
- CSP trough estimate includes six hours storage; CSP tower estimate includes six to fifteen hours storage.
- Estimate includes three hours storage.
- Low estimate utilizes wet cooling; high estimate utilizes dry cooling.

### 3.4.6.3 Projection of Cost Reductions

Compared to most resources considered in this study, solar thermal generation technologies are at a very early stage of commercialization, and there are yet substantial opportunities for technology improvements that would reduce capital costs. Recent engineering-economic studies on trough (Kutscher, 2010)
and tower (Kolb, 2011) technologies describe several of the key pathways to these cost reductions:

+ **Improvements in gross thermal efficiency** through the use of higher temperature heat transfer fluids (HTFs) would translate to lower capital costs through a reduction in the required solar collector area;

+ A number of opportunities for **better hardware design** in the components of the solar collectors—optimal mirror sizing, advanced receiver coatings, low cost foundations and support structures—would directly reduce system costs; and

+ **Reductions in storage system costs** could be achieved through the use of advanced HTFs that either enable storage at a higher temperature or allow for storage in a phase-change material.

Because of the relative lack of commercialization of solar thermal technologies and the uncertainty that the application of learning curves to such a technology can introduce, E3 uses a more direct approach to assess potential cost declines for solar thermal. By surveying engineering studies and integrated resource plans that have considered the potential cost declines for solar thermal over the next two decades, E3 has developed plausible trajectories for the capital costs of solar thermal with and without storage. With the substantial uncertainty surrounding any potential forecast of future costs, E3 has chosen not to distinguish between future costs of trough and tower technologies; however, the relative potential for cost reductions between the two has informed E3’s evaluation of future costs.

The recommended cost trajectories for solar thermal technologies, as well as the underlying data that constitute the bases for these recommendations, are
shown in Figure 12 and Figure 13. In these recommendations, E3 has specified cost reduction potential of 15% in the short-term (five years) and 30% in the long term (20 years) as plausible; year-by-year capital costs are evaluated through linear interpolation as shown in the figures. The specific point estimates of solar thermal costs shown in these two figures are summarized in detail in Table 27.

**Figure 12. Comparison of E3 recommended future costs for solar thermal trough and tower technologies without storage with other projections**
Figure 13. Comparison of E3 recommended future costs for solar thermal trough and tower technologies with six hours of thermal storage with other projections

Table 27. Point estimates of future solar thermal costs with and without storage.

<table>
<thead>
<tr>
<th>Source</th>
<th>Technology</th>
<th>Storage</th>
<th>Installation Vintage</th>
<th>Capital Cost [$/kW]</th>
</tr>
</thead>
<tbody>
<tr>
<td>APS IRP</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2015</td>
<td>$4,997</td>
</tr>
<tr>
<td>B&amp;V/NREL</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2010</td>
<td>$5,702</td>
</tr>
<tr>
<td>B&amp;V/NREL</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2015</td>
<td>$5,481</td>
</tr>
<tr>
<td>B&amp;V/NREL</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2020</td>
<td>$5,272</td>
</tr>
<tr>
<td>B&amp;V/NREL</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2025</td>
<td>$5,051</td>
</tr>
<tr>
<td>B&amp;V/NREL</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2030</td>
<td>$4,842</td>
</tr>
<tr>
<td>B&amp;V/NREL</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2035</td>
<td>$4,630</td>
</tr>
<tr>
<td>CPUC (LTPP)</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2010</td>
<td>$5,788</td>
</tr>
<tr>
<td>DOE Sunshot</td>
<td>Tower</td>
<td>0 hrs</td>
<td>2015</td>
<td>$4,368</td>
</tr>
<tr>
<td>DOE Sunshot</td>
<td>Tower</td>
<td>0 hrs</td>
<td>2020</td>
<td>$3,494</td>
</tr>
<tr>
<td>Source</td>
<td>Technology</td>
<td>Storage</td>
<td>Installation Vintage</td>
<td>Capital Cost [$/kW]</td>
</tr>
<tr>
<td>-----------------</td>
<td>------------</td>
<td>---------</td>
<td>----------------------</td>
<td>---------------------</td>
</tr>
<tr>
<td>DOE Sunshot</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2010</td>
<td>$ 4,914</td>
</tr>
<tr>
<td>DOE Sunshot</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2015</td>
<td>$ 4,477</td>
</tr>
<tr>
<td>DOE Sunshot</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2020</td>
<td>$ 3,604</td>
</tr>
<tr>
<td>IRENA 2012A</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2011</td>
<td>$ 5,023</td>
</tr>
<tr>
<td>IRENA 2012A</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2015</td>
<td>$ 4,368</td>
</tr>
<tr>
<td>Lazard</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2010</td>
<td>$ 5,679</td>
</tr>
<tr>
<td>NREL 2010</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2010</td>
<td>$ 5,058</td>
</tr>
<tr>
<td>NREL 2010</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2015</td>
<td>$ 4,617</td>
</tr>
<tr>
<td>NREL 2010</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2020</td>
<td>$ 3,697</td>
</tr>
<tr>
<td>PNM IRP</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2015</td>
<td>$ 4,702</td>
</tr>
<tr>
<td>Sandia 2011</td>
<td>Tower</td>
<td>0 hrs</td>
<td>2013</td>
<td>$ 5,491</td>
</tr>
<tr>
<td>Sandia 2011</td>
<td>Tower</td>
<td>0 hrs</td>
<td>2017</td>
<td>$ 4,556</td>
</tr>
<tr>
<td>Sandia 2011</td>
<td>Tower</td>
<td>0 hrs</td>
<td>2020</td>
<td>$ 3,517</td>
</tr>
<tr>
<td>TEP IRP</td>
<td>Trough</td>
<td>0 hrs</td>
<td>2015</td>
<td>$ 4,875</td>
</tr>
<tr>
<td>APS IRP</td>
<td>Tower</td>
<td>6 hrs</td>
<td>2015</td>
<td>$ 5,078</td>
</tr>
<tr>
<td>APS IRP</td>
<td>Trough</td>
<td>6 hrs</td>
<td>2015</td>
<td>$ 7,548</td>
</tr>
<tr>
<td>B&amp;V/NREL</td>
<td>Tower</td>
<td>6 hrs</td>
<td>2030</td>
<td>$ 6,166</td>
</tr>
<tr>
<td>B&amp;V/NREL</td>
<td>Trough</td>
<td>6 hrs</td>
<td>2035</td>
<td>$ 5,458</td>
</tr>
<tr>
<td>B&amp;V/NREL</td>
<td>Trough</td>
<td>6 hrs</td>
<td>2010</td>
<td>$ 8,198</td>
</tr>
<tr>
<td>B&amp;V/NREL</td>
<td>Trough</td>
<td>6 hrs</td>
<td>2015</td>
<td>$ 7,896</td>
</tr>
<tr>
<td>B&amp;V/NREL</td>
<td>Trough</td>
<td>6 hrs</td>
<td>2020</td>
<td>$ 7,583</td>
</tr>
<tr>
<td>B&amp;V/NREL</td>
<td>Trough</td>
<td>6 hrs</td>
<td>2025</td>
<td>$ 6,875</td>
</tr>
<tr>
<td>CPUC (LTPP)</td>
<td>Trough</td>
<td>6 hrs</td>
<td>2010</td>
<td>$ 8,190</td>
</tr>
<tr>
<td>CSIRO</td>
<td>Tower</td>
<td>6 hrs</td>
<td>2010</td>
<td>$ 8,957</td>
</tr>
<tr>
<td>CSIRO</td>
<td>Tower</td>
<td>6 hrs</td>
<td>2020</td>
<td>$ 6,487</td>
</tr>
<tr>
<td>CSIRO</td>
<td>Trough</td>
<td>6 hrs</td>
<td>2010</td>
<td>$ 9,281</td>
</tr>
<tr>
<td>CSIRO</td>
<td>Trough</td>
<td>6 hrs</td>
<td>2017</td>
<td>$ 5,591</td>
</tr>
<tr>
<td>DOE Sunshot</td>
<td>Tower</td>
<td>6 hrs</td>
<td>2015</td>
<td>$ 6,443</td>
</tr>
<tr>
<td>DOE Sunshot</td>
<td>Tower</td>
<td>6 hrs</td>
<td>2020</td>
<td>$ 4,696</td>
</tr>
<tr>
<td>DOE Sunshot</td>
<td>Trough</td>
<td>6 hrs</td>
<td>2010</td>
<td>$ 8,736</td>
</tr>
<tr>
<td>DOE Sunshot</td>
<td>Trough</td>
<td>6 hrs</td>
<td>2015</td>
<td>$ 8,190</td>
</tr>
</tbody>
</table>
### 3.4.7 WIND

#### 3.4.7.1 Technology Description

Wind power technologies include both onshore and offshore designs. Onshore wind is a mature technology, with roughly 13.1 GW of new capacity installed in the United States in 2012 (Wiser and Bolinger, 2013). On the other hand, no offshore wind turbines have been installed in the U.S., and this lack of commercialization is reflected in E3’s capital cost recommendation.
### Present-day Cost

**Table 28.** Onshore wind capital & O&M costs.

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M  [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avista IRP</td>
<td>$2,340</td>
<td>$53.0</td>
</tr>
<tr>
<td>WEC/BNEF</td>
<td>$1,867</td>
<td>$24.7</td>
</tr>
<tr>
<td>CEC 2013&lt;sup&gt;a&lt;/sup&gt;</td>
<td>$1,978</td>
<td>$32.7</td>
</tr>
<tr>
<td></td>
<td>$2,287</td>
<td>$32.7</td>
</tr>
<tr>
<td>EIA</td>
<td>$2,408</td>
<td>$41.0</td>
</tr>
<tr>
<td>EPRI 2013&lt;sup&gt;AB&lt;/sup&gt;</td>
<td>$1,933</td>
<td>$37.1</td>
</tr>
<tr>
<td></td>
<td>$2,648</td>
<td>$37.1</td>
</tr>
<tr>
<td>Idaho Power IRP&lt;sup&gt;f&lt;/sup&gt;</td>
<td>$2,455</td>
<td>$37.7</td>
</tr>
<tr>
<td></td>
<td>$2,514</td>
<td>$37.7</td>
</tr>
<tr>
<td>Lazard&lt;sup&gt;d&lt;/sup&gt;</td>
<td>$1,530</td>
<td>$30.6</td>
</tr>
<tr>
<td></td>
<td>$2,040</td>
<td>$30.6</td>
</tr>
<tr>
<td>LBNL (WTMR)</td>
<td>$2,016</td>
<td></td>
</tr>
<tr>
<td>PacifiCorp IRP&lt;sup&gt;e&lt;/sup&gt;</td>
<td>$2,218</td>
<td>$34.3</td>
</tr>
<tr>
<td></td>
<td>$2,453</td>
<td>$34.3</td>
</tr>
<tr>
<td>WREZ 3.0 (B&amp;V)&lt;sup&gt;f&lt;/sup&gt;</td>
<td>$1,887</td>
<td>$40.8</td>
</tr>
<tr>
<td></td>
<td>$2,321</td>
<td>$40.8</td>
</tr>
<tr>
<td><strong>Recommendation</strong></td>
<td><strong>$2,100</strong></td>
<td><strong>$30.0</strong></td>
</tr>
</tbody>
</table>

<sup>a</sup> Low estimate is a Class 4 100 MW wind plant; high estimate is a Class 3 100 MW wind plant.

<sup>b</sup> Range reflects cost uncertainty.

<sup>c</sup> The range presented reflects variation in plant location. Low estimate corresponds to wind plant installed in Magic Valley; high estimate corresponds to wind plant installed in eastern Oregon.

<sup>d</sup> Range reflects cost uncertainty.

<sup>e</sup> The range presented reflects variation in plant location. Low estimate corresponds to wind plant installed in Wyoming; high estimate corresponds to wind plant installed in Washington.

<sup>f</sup> Low estimate corresponds to wind plant utilizing IEC Class 1 turbine at 80 meter hub height; high estimate corresponds to wind plant utilizing IEC Class 3 turbine at 100 meter hub height.
Table 29. Offshore wind capital and O&M costs.

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>B&amp;V/NREL*</td>
<td>$3,856</td>
<td>$111</td>
</tr>
<tr>
<td></td>
<td>$4,893</td>
<td>$144</td>
</tr>
<tr>
<td>EIA</td>
<td>$6,780</td>
<td>$77</td>
</tr>
<tr>
<td>EPRI 2013A</td>
<td>$3,442</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>$5,533</td>
<td>-</td>
</tr>
<tr>
<td>Lazard</td>
<td>$3,162</td>
<td>$61</td>
</tr>
<tr>
<td></td>
<td>$5,100</td>
<td>$102</td>
</tr>
<tr>
<td>Recommendation</td>
<td>$6,300</td>
<td>$105</td>
</tr>
</tbody>
</table>

* Low estimate assumes fixed-bottom offshore wind technology; high estimate assumes floating-platform offshore wind technology.

3.4.7.3 Market Benchmark

Over the past several years, utilities in the Rocky Mountains have signed a number of very low-priced PPAs for wind resources. The terms and structures of these PPAs very dramatically, but in many cases, quoted figures are first-year prices for an escalating PPA. For example, Southwestern Public Company signed three power purchase agreements in 2013 with a beginning PPA price of $19.2 - $21.1 per MWh that includes escalation of 1.8 – 2.0% and excludes RECs. Public Service Company of Colorado signed two power purchase agreements in 2011 with a beginning PPA price of $27.5 - $29.4 per MWh that includes escalation of 2.0 – 2.8% and includes RECs.

E3 has used its cost recommendations and its pro-forma financing model to calculate benchmark PPA prices for a 100 MW wind plant based on characteristics and financing terms that are chosen with the intent to mimic
resources purchased by utilities. Table 30 outlines the assumptions and calculated prices for a PPA with no escalation and one assuming escalation of 2% per year. E3 calculated an LCOE of $34/MWh for the benchmark resource assuming no escalation and $29/MWh if the PPA price escalated at 2% per year.

Table 30. Benchmark PPA price for onshore wind plant installed in 2013 in the Rocky Mountain region.

<table>
<thead>
<tr>
<th>Item</th>
<th>Units</th>
<th>No Escalation</th>
<th>2% per year Escalation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Cost</td>
<td>$/kW</td>
<td>$2,100</td>
<td>$2,100</td>
</tr>
<tr>
<td>Fixed O&amp;M</td>
<td>$/kW-yr</td>
<td>$25</td>
<td>$25</td>
</tr>
<tr>
<td>Capacity Factor</td>
<td>% (ac)</td>
<td>45%</td>
<td>45%</td>
</tr>
<tr>
<td>MACRS</td>
<td>yrs</td>
<td>5 + bonus</td>
<td>5 + bonus</td>
</tr>
<tr>
<td>After-tax WACC</td>
<td>%</td>
<td>7.5%</td>
<td>7.5%</td>
</tr>
<tr>
<td>Production Tax Credit</td>
<td>$/MWh</td>
<td>$23</td>
<td>$23</td>
</tr>
<tr>
<td>PPA Term</td>
<td>yrs</td>
<td>25</td>
<td>25</td>
</tr>
<tr>
<td>Escalation</td>
<td>%/yr</td>
<td>0%</td>
<td>2%</td>
</tr>
<tr>
<td>Calculated PPA Price</td>
<td>$/MWh</td>
<td>$34</td>
<td>$29</td>
</tr>
</tbody>
</table>

3.4.7.4 Projection of Cost Reductions

E3 applies the learning curve approach to current wind costs to assess potential cost reductions. Compared to solar PV, there is less consensus in academic literature on an appropriate learning rate for wind; estimates range from 0%-14%. E3 has chosen to apply a learning rate of 5% in conjunction with the forecast of global installed capacity from the IEA’s 2013 market report (IEA, 2013). The forecast used in this calculation is shown in Figure 14; the resulting trajectory of cost reductions follows in Figure 15.
Figure 14. Forecast of global installed wind capacity used to evaluate potential cost reductions through application of learning curves.

Figure 15. Projected capital cost reductions for wind based on learning curves.
3.5 Storage Technologies

3.5.1 PUMPED STORAGE

3.5.1.1 Technology Description

Pumped storage projects store and generate energy by moving water between two reservoirs at different elevations. Generally speaking, at times of low electricity demand excess energy is used to pump water to an upper reservoir. During periods of high electricity demand, the stored water is released through turbines in the same manner as a conventional hydro station to generate electricity. Capital costs for new pumped storage facilities are site-specific and can vary greatly depending on the location. This report provides generic cost estimates for a hydro pumped storage facility in the west that exceeds 250 MW.

3.5.1.2 Present-day Cost

Table 31. Pumped hydro capital and O&M costs.

<table>
<thead>
<tr>
<th>Source</th>
<th>Capital Cost [$/kW]</th>
<th>Fixed O&amp;M [$/kW-yr]</th>
</tr>
</thead>
<tbody>
<tr>
<td>B&amp;V/NREL</td>
<td>$2,476</td>
<td></td>
</tr>
<tr>
<td>Eagle Mountain</td>
<td>$1,500</td>
<td>$2,000</td>
</tr>
<tr>
<td>EIA</td>
<td>$5,485</td>
<td>$18.7</td>
</tr>
<tr>
<td>EPRI 2013B</td>
<td>$1,556</td>
<td>$2,429</td>
</tr>
<tr>
<td>HDR</td>
<td>$1,556</td>
<td>$3,112</td>
</tr>
<tr>
<td>Idaho Power IRP</td>
<td>$3,115</td>
<td></td>
</tr>
<tr>
<td>PacifiCorp IRP</td>
<td>$3,112</td>
<td>$4.5</td>
</tr>
</tbody>
</table>
### 3.5.2 BATTERY

#### 3.5.2.1 Technology Description

Batteries vary widely in terms of characteristics: size, storage capacity, technology maturity, etc. Only currently deployed utility-scale batteries (>1 MW) were considered. The assumed characteristics of a generic battery includes 8 hour storage capacity and 75% round trip efficiency.

#### 3.5.2.2 Present-day Cost

**Table 32. Battery capital and O&M costs.**

<table>
<thead>
<tr>
<th>Source</th>
<th>Type</th>
<th>Capital Cost $/kW</th>
<th>Fixed O&amp;M $/kW-yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avista IRP</td>
<td>Generic</td>
<td>$3,889</td>
<td>$52</td>
</tr>
<tr>
<td>B&amp;V/NREL</td>
<td>Sodium sulfur</td>
<td>$4,470</td>
<td></td>
</tr>
<tr>
<td>IRENA 2012B</td>
<td>Lithium ion</td>
<td>$2,853</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Sodium sulfur</td>
<td>$2,075</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Vanadium redox</td>
<td>$3,631</td>
<td></td>
</tr>
<tr>
<td>PacifiCorp IRP</td>
<td>Lithium ion</td>
<td>$1,177</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Sodium sulfur</td>
<td>$5,736</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Vanadium redox</td>
<td>$9,037</td>
<td></td>
</tr>
<tr>
<td>Sandia 2013</td>
<td>Vanadium redox</td>
<td>$3,809</td>
<td></td>
</tr>
<tr>
<td><strong>Recommendation</strong></td>
<td></td>
<td><strong>$4,500</strong></td>
<td><strong>$50</strong></td>
</tr>
</tbody>
</table>
4 Regional Cost Adjustments

The capital cost recommendations that E3 has developed are intended to represent the average cost of building new generation in the Western Interconnect; however, due to regional differences in the cost of labor and materials, plant construction costs will vary from state to state. To account for the regional differences in expected plant costs, E3 has developed state-specific multipliers for each technology based on the cost indices in the US Army Corps Civil Works Construction Cost Indexing System (CWCCIS) (USACE, 2011). A summary of the indices for the WECC states and provinces is shown in column 2 of the table below. Based on information obtained from the ACE Cost Analysis Department, the input costs for this index are about 37% labor, 37% materials, and 26% equipment. For this analysis, E3 estimated that 100% of labor costs were variable by region, 50% of materials costs were variable by region, and equipment costs were constant across all regions. Using the proportion of the Army Corp of Engineers costs that came from each expense category, E3 backed out a multiplier for each area that would apply only to the variable portion (i.e. labor costs and 50% of material costs) of any project, shown as the Variable Cost Index below.
Regional Cost Adjustments

Table 33. USACE Civil Works Construction Cost Indices and the regional differences in regionally-variable costs.

<table>
<thead>
<tr>
<th>State/Province</th>
<th>CWCCIS Cost Index</th>
<th>Variable Cost Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alberta&lt;sup&gt;a&lt;/sup&gt;</td>
<td>1.00</td>
<td>1.00</td>
</tr>
<tr>
<td>Arizona</td>
<td>0.96</td>
<td>0.93</td>
</tr>
<tr>
<td>British Columbia&lt;sup&gt;a&lt;/sup&gt;</td>
<td>1.00</td>
<td>1.00</td>
</tr>
<tr>
<td>California</td>
<td>1.18</td>
<td>1.32</td>
</tr>
<tr>
<td>CFE&lt;sup&gt;b&lt;/sup&gt;</td>
<td>0.90</td>
<td>0.82</td>
</tr>
<tr>
<td>Colorado</td>
<td>0.99</td>
<td>0.98</td>
</tr>
<tr>
<td>Idaho</td>
<td>0.95</td>
<td>0.91</td>
</tr>
<tr>
<td>Montana</td>
<td>0.97</td>
<td>0.95</td>
</tr>
<tr>
<td>New Mexico</td>
<td>0.95</td>
<td>0.91</td>
</tr>
<tr>
<td>Nevada</td>
<td>1.08</td>
<td>1.14</td>
</tr>
<tr>
<td>Oregon</td>
<td>1.07</td>
<td>1.13</td>
</tr>
<tr>
<td>Texas</td>
<td>0.87</td>
<td>0.77</td>
</tr>
<tr>
<td>Utah</td>
<td>0.95</td>
<td>0.91</td>
</tr>
<tr>
<td>Washington</td>
<td>1.07</td>
<td>1.13</td>
</tr>
<tr>
<td>Wyoming</td>
<td>0.90</td>
<td>0.82</td>
</tr>
</tbody>
</table>

<sup>a</sup> Regional cost multipliers for Canadian provinces were assumed to be equal to 1.

<sup>b</sup> Regional cost multiplier for CFE was assumed to be equal to the smallest regional multiplier among WECC states (Wyoming).

To determine a technology-specific regional adjustment for each technology, E3 has developed assumptions on the relative contribution of labor, equipment, and materials to each type of new generation. These assumptions are shown in Table 34.
Table 34. Contribution of labor, materials, and equipment to the capital costs of each type of new generation.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Labor</th>
<th>Materials</th>
<th>Equipment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biogas</td>
<td>25%</td>
<td>15%</td>
<td>60%</td>
</tr>
<tr>
<td>Biomass</td>
<td>45%</td>
<td>15%</td>
<td>40%</td>
</tr>
<tr>
<td>CHP</td>
<td>20%</td>
<td>8%</td>
<td>73%</td>
</tr>
<tr>
<td>Coal – PC</td>
<td>33%</td>
<td>5%</td>
<td>63%</td>
</tr>
<tr>
<td>Coal – IGCC</td>
<td>28%</td>
<td>5%</td>
<td>68%</td>
</tr>
<tr>
<td>Gas CGT</td>
<td>20%</td>
<td>8%</td>
<td>73%</td>
</tr>
<tr>
<td>Gas CT</td>
<td>50%</td>
<td>15%</td>
<td>35%</td>
</tr>
<tr>
<td>Geothermal</td>
<td>15%</td>
<td>35%</td>
<td>50%</td>
</tr>
<tr>
<td>Hydro – Pumped Storage</td>
<td>40%</td>
<td>30%</td>
<td>30%</td>
</tr>
<tr>
<td>Hydro – Large</td>
<td>40%</td>
<td>30%</td>
<td>30%</td>
</tr>
<tr>
<td>Hydro – Small</td>
<td>50%</td>
<td>30%</td>
<td>20%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>40%</td>
<td>40%</td>
<td>20%</td>
</tr>
<tr>
<td>Reciprocating Engines</td>
<td>50%</td>
<td>15%</td>
<td>35%</td>
</tr>
<tr>
<td>Solar PV</td>
<td>15%</td>
<td>15%</td>
<td>70%</td>
</tr>
<tr>
<td>Solar Thermal</td>
<td>20%</td>
<td>40%</td>
<td>40%</td>
</tr>
<tr>
<td>Wind</td>
<td>10%</td>
<td>20%</td>
<td>70%</td>
</tr>
</tbody>
</table>

Maintaining the assumptions that 100% of labor costs, 50% of materials costs, and 0% of equipment costs are variable by region, the information in Table 33 and Table 34 are combined to derive technology-specific state cost adjustment factors. These adjustment factors are shown in Table 35. E3 assumed that battery capital costs are equivalent across all regions.

It should be noted that while these adjustment factors capture directional differences in capital costs in the WECC, they are approximations, and actual plant costs may vary substantially from the results obtained using these factors. Besides variances related to regional costs of labor and materials, the costs of
building and operating new generation will depend on such site-specific factors as property taxes, state and local sales taxes. Accordingly, while these factors are useful for WECC modeling, they are not a replacement for site- or case-specific evaluations of project capital and O&M costs.
Table 35. Technology-specific regional cost multipliers (technology-specific multipliers apply to capital costs; fixed O&M multiplier applies to fixed O&M for all technologies).

<table>
<thead>
<tr>
<th>State/Province</th>
<th>AB</th>
<th>AZ</th>
<th>BC</th>
<th>CA</th>
<th>CFE</th>
<th>CO</th>
<th>ID</th>
<th>MT</th>
<th>NV</th>
<th>NM</th>
<th>OR</th>
<th>TX</th>
<th>UT</th>
<th>WA</th>
<th>WY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Battery</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
</tr>
<tr>
<td>Biogas</td>
<td>1.000</td>
<td>0.977</td>
<td>1.000</td>
<td>1.105</td>
<td>0.941</td>
<td>0.994</td>
<td>0.971</td>
<td>0.982</td>
<td>1.047</td>
<td>0.971</td>
<td>1.041</td>
<td>0.924</td>
<td>0.971</td>
<td>1.041</td>
<td>0.941</td>
</tr>
<tr>
<td>Biomass</td>
<td>1.000</td>
<td>0.962</td>
<td>1.000</td>
<td>1.170</td>
<td>0.905</td>
<td>0.991</td>
<td>0.953</td>
<td>0.972</td>
<td>1.076</td>
<td>0.953</td>
<td>1.066</td>
<td>0.877</td>
<td>0.953</td>
<td>1.066</td>
<td>0.905</td>
</tr>
<tr>
<td>CHP</td>
<td>1.000</td>
<td>0.983</td>
<td>1.000</td>
<td>1.077</td>
<td>0.957</td>
<td>0.996</td>
<td>0.979</td>
<td>0.987</td>
<td>1.034</td>
<td>0.979</td>
<td>1.030</td>
<td>0.944</td>
<td>0.979</td>
<td>1.030</td>
<td>0.957</td>
</tr>
<tr>
<td>Coal – PC</td>
<td>1.000</td>
<td>0.975</td>
<td>1.000</td>
<td>1.114</td>
<td>0.937</td>
<td>0.994</td>
<td>0.968</td>
<td>0.981</td>
<td>1.050</td>
<td>0.968</td>
<td>1.044</td>
<td>0.918</td>
<td>0.968</td>
<td>1.044</td>
<td>0.937</td>
</tr>
<tr>
<td>Coal – IGCC</td>
<td>1.000</td>
<td>0.978</td>
<td>1.000</td>
<td>1.097</td>
<td>0.946</td>
<td>0.995</td>
<td>0.973</td>
<td>0.984</td>
<td>1.043</td>
<td>0.973</td>
<td>1.038</td>
<td>0.930</td>
<td>0.973</td>
<td>1.038</td>
<td>0.946</td>
</tr>
<tr>
<td>Gas CCGT</td>
<td>1.000</td>
<td>0.983</td>
<td>1.000</td>
<td>1.077</td>
<td>0.957</td>
<td>0.996</td>
<td>0.979</td>
<td>0.987</td>
<td>1.034</td>
<td>0.979</td>
<td>1.030</td>
<td>0.944</td>
<td>0.979</td>
<td>1.030</td>
<td>0.957</td>
</tr>
<tr>
<td>Gas CT</td>
<td>1.000</td>
<td>0.959</td>
<td>1.000</td>
<td>1.186</td>
<td>0.896</td>
<td>0.990</td>
<td>0.948</td>
<td>0.989</td>
<td>1.083</td>
<td>0.948</td>
<td>1.073</td>
<td>0.865</td>
<td>0.948</td>
<td>1.073</td>
<td>0.896</td>
</tr>
<tr>
<td>Geothermal</td>
<td>1.000</td>
<td>0.977</td>
<td>1.000</td>
<td>1.105</td>
<td>0.941</td>
<td>0.994</td>
<td>0.971</td>
<td>0.982</td>
<td>1.047</td>
<td>0.971</td>
<td>1.041</td>
<td>0.924</td>
<td>0.971</td>
<td>1.041</td>
<td>0.941</td>
</tr>
<tr>
<td>Hydro – PS</td>
<td>1.000</td>
<td>0.960</td>
<td>1.000</td>
<td>1.178</td>
<td>0.901</td>
<td>0.990</td>
<td>0.950</td>
<td>0.970</td>
<td>1.079</td>
<td>0.950</td>
<td>1.069</td>
<td>0.871</td>
<td>0.850</td>
<td>1.069</td>
<td>0.901</td>
</tr>
<tr>
<td>Hydro – Large</td>
<td>1.000</td>
<td>0.960</td>
<td>1.000</td>
<td>1.178</td>
<td>0.901</td>
<td>0.990</td>
<td>0.950</td>
<td>0.970</td>
<td>1.079</td>
<td>0.950</td>
<td>1.069</td>
<td>0.871</td>
<td>0.850</td>
<td>1.069</td>
<td>0.901</td>
</tr>
<tr>
<td>Hydro – Small</td>
<td>1.000</td>
<td>0.953</td>
<td>1.000</td>
<td>1.211</td>
<td>0.883</td>
<td>0.988</td>
<td>0.941</td>
<td>0.965</td>
<td>1.094</td>
<td>0.941</td>
<td>1.082</td>
<td>0.848</td>
<td>0.941</td>
<td>1.082</td>
<td>0.883</td>
</tr>
<tr>
<td>Nuclear</td>
<td>1.000</td>
<td>0.957</td>
<td>1.000</td>
<td>1.195</td>
<td>0.892</td>
<td>0.989</td>
<td>0.946</td>
<td>0.968</td>
<td>1.086</td>
<td>0.946</td>
<td>1.076</td>
<td>0.859</td>
<td>0.946</td>
<td>1.076</td>
<td>0.892</td>
</tr>
<tr>
<td>Recip. Engine</td>
<td>1.000</td>
<td>0.959</td>
<td>1.000</td>
<td>1.186</td>
<td>0.896</td>
<td>0.990</td>
<td>0.948</td>
<td>0.989</td>
<td>1.083</td>
<td>0.948</td>
<td>1.073</td>
<td>0.865</td>
<td>0.948</td>
<td>1.073</td>
<td>0.896</td>
</tr>
<tr>
<td>Solar PV</td>
<td>1.000</td>
<td>0.984</td>
<td>1.000</td>
<td>1.073</td>
<td>0.959</td>
<td>0.996</td>
<td>0.980</td>
<td>0.988</td>
<td>1.032</td>
<td>0.980</td>
<td>1.028</td>
<td>0.947</td>
<td>0.980</td>
<td>1.028</td>
<td>0.959</td>
</tr>
<tr>
<td>Solar Thermal</td>
<td>1.000</td>
<td>0.971</td>
<td>1.000</td>
<td>1.130</td>
<td>0.928</td>
<td>0.993</td>
<td>0.964</td>
<td>0.978</td>
<td>1.058</td>
<td>0.964</td>
<td>1.050</td>
<td>0.906</td>
<td>0.964</td>
<td>1.050</td>
<td>0.928</td>
</tr>
<tr>
<td>Wind</td>
<td>1.000</td>
<td>0.986</td>
<td>1.000</td>
<td>1.065</td>
<td>0.964</td>
<td>0.996</td>
<td>0.982</td>
<td>0.989</td>
<td>1.029</td>
<td>0.982</td>
<td>1.025</td>
<td>0.953</td>
<td>0.982</td>
<td>1.025</td>
<td>0.964</td>
</tr>
<tr>
<td>Fixed O&amp;M</td>
<td>1.000</td>
<td>0.971</td>
<td>1.000</td>
<td>1.130</td>
<td>0.928</td>
<td>0.993</td>
<td>0.964</td>
<td>0.978</td>
<td>1.058</td>
<td>0.964</td>
<td>1.050</td>
<td>0.906</td>
<td>0.964</td>
<td>1.050</td>
<td>0.928</td>
</tr>
</tbody>
</table>
5 Calculations of Annualized Resource Costs

5.1 Cash Flow Models for 10-Year Study

In order to translate the capital and fixed cost recommendations into values useful for WECC’s snapshot studies, E3 has developed three Excel-based cash flow models that represent different options for project financing. Each model develops an annual stream of costs and revenues that results in the specified return to the financing entity.

5.1.1 INDEPENDENT POWER PRODUCER

E3 has developed a cash-flow model that evaluates a cost-based power-purchase agreement price for new generation under the assumption that a project is funded and financed by an IPP under long-term contract to a utility. The pro-forma model is designed to ensure that the long-term power price will provide equity investors with appropriate return on and of their capital investment. E3’s model also maximizes leverage, assuming that projects will be debt-funded to the maximum extent possible subject to the constraint that the project’s average debt-service coverage ratio remains above 1.40. Accordingly, the project’s capital structure is endogenous to the financing model and is based on an assumption that the IPP’s after-tax WACC, the weighted average
cost of capital of debt and equity with which the project is financed, will be 8.30%. This assumed WACC is intended to represent a long-run cost of capital and is higher than the cost of capital might be in today’s low interest rate environment. Figure 16 provides a screenshot of the first five years of the IPP cash flow model.

Figure 16. Screenshot of IPP cash flow model (first five years)

### IPP Pro Forma

<table>
<thead>
<tr>
<th>Year</th>
<th>0</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>3,723,000</td>
<td>3,713,693</td>
<td>3,704,408</td>
<td>3,695,147</td>
<td>3,685,909</td>
</tr>
<tr>
<td>Energy Production (MWh)</td>
<td></td>
<td>$87.46</td>
<td>$87.46</td>
<td>$87.46</td>
<td>$87.46</td>
<td>$87.46</td>
</tr>
<tr>
<td>Cost of Generation ($/MWh)</td>
<td></td>
<td>$325,597,228</td>
<td>$324,783,235</td>
<td>$323,971,277</td>
<td>$323,161,349</td>
<td>$322,353,446</td>
</tr>
<tr>
<td>Operating Revenue</td>
<td></td>
<td>$325,597,228</td>
<td>$324,783,235</td>
<td>$323,971,277</td>
<td>$323,161,349</td>
<td>$322,353,446</td>
</tr>
<tr>
<td>Total Revenue</td>
<td></td>
<td>$325,597,228</td>
<td>$324,783,235</td>
<td>$323,971,277</td>
<td>$323,161,349</td>
<td>$322,353,446</td>
</tr>
<tr>
<td>Fixed O&amp;M Costs</td>
<td></td>
<td>($5,100,000)</td>
<td>($5,202,000)</td>
<td>($5,306,040)</td>
<td>($5,412,161)</td>
<td>($5,520,404)</td>
</tr>
<tr>
<td>Variable O&amp;M Cost</td>
<td></td>
<td>($188,837,845)</td>
<td>($192,613,398)</td>
<td>($196,464,438)</td>
<td>($200,392,474)</td>
<td>($204,399,046)</td>
</tr>
<tr>
<td>Fuel Costs</td>
<td></td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Property Tax</td>
<td></td>
<td>($5,500,000)</td>
<td>($5,225,000)</td>
<td>($4,950,000)</td>
<td>($4,675,000)</td>
<td>($4,400,000)</td>
</tr>
<tr>
<td>Insurance</td>
<td></td>
<td>($2,805,000)</td>
<td>($2,861,100)</td>
<td>($2,918,322)</td>
<td>($2,976,688)</td>
<td>($3,036,222)</td>
</tr>
<tr>
<td>Total Costs</td>
<td></td>
<td>($220,850,399)</td>
<td>($224,833,754)</td>
<td>($228,901,423)</td>
<td>($233,055,080)</td>
<td>($237,296,427)</td>
</tr>
<tr>
<td>Operating Profit</td>
<td></td>
<td>$104,746,830</td>
<td>$99,949,482</td>
<td>$95,069,854</td>
<td>$90,106,269</td>
<td>$85,057,019</td>
</tr>
<tr>
<td>Loan Repayment Expense (Principal)</td>
<td></td>
<td>($12,654,547)</td>
<td>($13,540,365)</td>
<td>($14,488,191)</td>
<td>($15,302,364)</td>
<td>($16,087,530)</td>
</tr>
<tr>
<td>Debt Service Reserve</td>
<td></td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Interest earned on DSRF</td>
<td></td>
<td>$721,462</td>
<td>$721,462</td>
<td>$721,462</td>
<td>$721,462</td>
<td>$721,462</td>
</tr>
<tr>
<td>Net Finance Costs</td>
<td></td>
<td>($42,050,050)</td>
<td>($42,050,050)</td>
<td>($42,050,050)</td>
<td>($42,050,050)</td>
<td>($42,050,050)</td>
</tr>
<tr>
<td>State tax refund/(paid)</td>
<td></td>
<td>($3,830,843)</td>
<td>($2,221,471)</td>
<td>($2,154,915)</td>
<td>($2,070,956)</td>
<td>($1,972,110)</td>
</tr>
<tr>
<td>Federal tax refund (paid)</td>
<td></td>
<td>($17,813,419)</td>
<td>($10,329,839)</td>
<td>($10,020,353)</td>
<td>($9,629,945)</td>
<td>($9,170,311)</td>
</tr>
<tr>
<td>Tax Credit - Federal PTC</td>
<td></td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Tax Credit - Federal ITC</td>
<td></td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Taxes Refunded/(Paid)</td>
<td></td>
<td>($21,644,262)</td>
<td>($12,551,310)</td>
<td>($12,175,268)</td>
<td>($11,700,901)</td>
<td>($11,142,421)</td>
</tr>
<tr>
<td>Equity Investment</td>
<td></td>
<td>($140,370,848)</td>
<td>($41,052,518)</td>
<td>$45,349,122</td>
<td>$40,844,536</td>
<td>$36,355,319</td>
</tr>
<tr>
<td>After-Tax Equity Cash Flow</td>
<td></td>
<td>($140,370,848)</td>
<td>($41,052,518)</td>
<td>$45,349,122</td>
<td>$40,844,536</td>
<td>$36,355,319</td>
</tr>
</tbody>
</table>

### Table 1

#### 5.1.2 INVESTOR-OWNED UTILITY/PUBLICLY-OWNED UTILITY

E3 has also developed a cash flow model for projects that are utility-owned and whose capital costs are recovered through rate base. The revenue requirement approach assumes a fixed utility capital structure; assumptions on the costs of
debt and equity are shown in Table 36. The models for IOU- and POU-financing differ only in that POUs are exempt from income tax and projects are entirely debt-financed.

**Table 36. Capital structure for IOU and POU financing.**

<table>
<thead>
<tr>
<th>Technology</th>
<th>IOU</th>
<th>POU</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equity Share</td>
<td>50%</td>
<td>-</td>
</tr>
<tr>
<td>Debt Share</td>
<td>50%</td>
<td>100%</td>
</tr>
<tr>
<td>Equity Cost</td>
<td>11.0%</td>
<td>-</td>
</tr>
<tr>
<td>Debt Cost</td>
<td>6.0%</td>
<td>6.3%</td>
</tr>
<tr>
<td><strong>After-Tax WACC</strong></td>
<td><strong>7.3%</strong></td>
<td><strong>6.3%</strong></td>
</tr>
</tbody>
</table>

Figure 17 provides a screenshot of the first five years of the IOU revenue requirement model.
Figure 17. Screenshot of IOU cash flow model (first five years).

## IOU Pro Forma

<table>
<thead>
<tr>
<th>Year</th>
<th>0</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy Production (MWh)</td>
<td>105,120</td>
<td>104,069</td>
<td>103,028</td>
<td>101,998</td>
<td>100,978</td>
<td></td>
</tr>
<tr>
<td>Debt Term Flag</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Capital Cost</td>
<td>$180,000,000</td>
<td>$180,000,000</td>
<td>$180,000,000</td>
<td>$180,000,000</td>
<td>$180,000,000</td>
<td></td>
</tr>
<tr>
<td>Starting Rate Base</td>
<td>$180,000,000</td>
<td>$160,321,500</td>
<td>$132,100,200</td>
<td>$112,991,220</td>
<td>$99,349,632</td>
<td></td>
</tr>
<tr>
<td>Accumulated Deferred Income Tax</td>
<td>$(10,678,500)</td>
<td>$(29,899,800)</td>
<td>$(40,008,780)</td>
<td>$(44,650,368)</td>
<td>$(49,291,956)</td>
<td></td>
</tr>
<tr>
<td>Accumulated Depreciation</td>
<td>$(9,000,000)</td>
<td>$(18,000,000)</td>
<td>$(27,000,000)</td>
<td>$(36,000,000)</td>
<td>$(45,000,000)</td>
<td></td>
</tr>
<tr>
<td>Ending Balance Rate Base</td>
<td>$180,000,000</td>
<td>$160,321,500</td>
<td>$132,100,200</td>
<td>$112,991,220</td>
<td>$99,349,632</td>
<td></td>
</tr>
<tr>
<td>Debt Beginning Balance</td>
<td>$90,000,000</td>
<td>$80,160,750</td>
<td>$66,050,100</td>
<td>$56,495,610</td>
<td>$49,674,816</td>
<td></td>
</tr>
<tr>
<td>Interest</td>
<td>$5,400,000</td>
<td>$4,809,645</td>
<td>$3,963,006</td>
<td>$3,389,737</td>
<td>$2,980,489</td>
<td></td>
</tr>
<tr>
<td>Principal</td>
<td>$4,500,000</td>
<td>$4,500,000</td>
<td>$4,500,000</td>
<td>$4,500,000</td>
<td>$4,500,000</td>
<td></td>
</tr>
<tr>
<td>Equity Beginning Balance</td>
<td>$90,000,000</td>
<td>$80,160,750</td>
<td>$66,050,100</td>
<td>$56,495,610</td>
<td>$49,674,816</td>
<td></td>
</tr>
<tr>
<td>Equity Return</td>
<td>$9,900,000</td>
<td>$8,817,683</td>
<td>$7,265,511</td>
<td>$6,214,517</td>
<td>$5,464,230</td>
<td></td>
</tr>
<tr>
<td>Return of Invested Equity</td>
<td>$4,500,000</td>
<td>$4,500,000</td>
<td>$4,500,000</td>
<td>$4,500,000</td>
<td>$4,500,000</td>
<td></td>
</tr>
<tr>
<td>Book Equity Return</td>
<td>$14,400,000</td>
<td>$13,317,683</td>
<td>$11,765,511</td>
<td>$10,714,517</td>
<td>$9,964,230</td>
<td></td>
</tr>
<tr>
<td>Equity Return</td>
<td>$9,900,000</td>
<td>$8,817,683</td>
<td>$7,265,511</td>
<td>$6,214,517</td>
<td>$5,464,230</td>
<td></td>
</tr>
<tr>
<td>Tax on Equity Return</td>
<td>$3,915,450</td>
<td>$3,487,393</td>
<td>$2,873,510</td>
<td>$2,457,842</td>
<td>$2,161,103</td>
<td></td>
</tr>
<tr>
<td>Amortized ITC</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td></td>
</tr>
<tr>
<td>PTC</td>
<td>($2,358,893)</td>
<td>($2,382,010)</td>
<td>($2,405,354)</td>
<td>($2,428,926)</td>
<td>($2,452,730)</td>
<td></td>
</tr>
<tr>
<td>Tax Grossup - Equity</td>
<td>$2,561,721</td>
<td>$2,281,661</td>
<td>$1,880,022</td>
<td>$1,608,067</td>
<td>$1,433,923</td>
<td></td>
</tr>
<tr>
<td>Tax Grossup - ITC</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td></td>
</tr>
<tr>
<td>Tax Grossup - PTC</td>
<td>($1,543,329)</td>
<td>($1,558,453)</td>
<td>($1,573,726)</td>
<td>($1,589,149)</td>
<td>($1,604,722)</td>
<td></td>
</tr>
<tr>
<td>Revenue Requirement</td>
<td>$29,628,950</td>
<td>$27,264,999</td>
<td>$23,868,230</td>
<td>$21,574,654</td>
<td>$19,943,311</td>
<td></td>
</tr>
</tbody>
</table>

### 5.2 Simple Annualization for 20-Year Study

WECC has also requested that E3 provide a purely algebraic, non-cash flow methodology to calculate levelized costs that can be integrated simply into the 20-year LTPT models directly. This is a challenging exercise, as the effects of variances in tax benefits from year to year cannot be precisely captured without considering annual cash flow streams. However, NREL provides a calculation...
that reasonably approximates E3’s detailed cash flows through the use of a Capital Recovery Factor (CRF) (Short, 1995). E3 has provided WECC with a simplified levelized cost calculator based on this approach to be incorporated directly in the LTPT. However, wherever possible, E3 recommends the use of its more detailed cash flow financing models to calculate levelized costs.

5.3 Financing and Tax Assumptions

5.3.1 RESOURCE FINANCING LIFETIMES

The recommended financing lifetimes for the various resources characterized in this study are summarized in Table 37. One important note is that the financing lifetime should not be interpreted as an expectation of the total operating lifetime of the plant. Rather, it is an assumption of the period over which the costs of the plant would be passed on to ratepayers.

Most new generation resources are assumed to be developed by IPPs under long-term contract to utilities. The length of such contractual arrangements can vary from 10 to 25 years. E3 recommends assuming a uniform, 20-year PPA between the IPP and the utility through which the full capital costs are recovered.

There are several resource types that are unlikely to be developed by IPPs: any new coal, large hydro, or nuclear resources would likely be developed as utility-owned assets. For these resources, the financing lifetime represents typical depreciable lifetimes over which the resource’s capital costs would be recovered in rate base. While these assumed lifetimes can vary substantially by
utility, E3 recommends assuming IOU financing over a 40-year lifetime for these resource types.

**Table 37. Default assumptions for financing entities and lifetimes for each generation technology.**

<table>
<thead>
<tr>
<th>Technology</th>
<th>Default Financing Entity</th>
<th>Assumed Financing Lifetime</th>
</tr>
</thead>
<tbody>
<tr>
<td>Battery</td>
<td>IPP</td>
<td>15</td>
</tr>
<tr>
<td>Biogas</td>
<td>IPP</td>
<td>20</td>
</tr>
<tr>
<td>Biomass</td>
<td>IPP</td>
<td>20</td>
</tr>
<tr>
<td>Coal – PC</td>
<td>IOU</td>
<td>40</td>
</tr>
<tr>
<td>Coal – IGCC</td>
<td>IOU</td>
<td>40</td>
</tr>
<tr>
<td>CHP</td>
<td>IPP</td>
<td>20</td>
</tr>
<tr>
<td>Gas – CCGT</td>
<td>IPP</td>
<td>20</td>
</tr>
<tr>
<td>Gas – CT</td>
<td>IPP</td>
<td>20</td>
</tr>
<tr>
<td>Geothermal</td>
<td>IPP</td>
<td>20</td>
</tr>
<tr>
<td>Hydro – Pumped Storage</td>
<td>IOU</td>
<td>40</td>
</tr>
<tr>
<td>Hydro – Large</td>
<td>IOU</td>
<td>40</td>
</tr>
<tr>
<td>Hydro – Small</td>
<td>IPP</td>
<td>20</td>
</tr>
<tr>
<td>Nuclear</td>
<td>IOU</td>
<td>40</td>
</tr>
<tr>
<td>Solar Thermal</td>
<td>IPP</td>
<td>20</td>
</tr>
<tr>
<td>Reciprocating Engine</td>
<td>IPP</td>
<td>20</td>
</tr>
<tr>
<td>Solar PV</td>
<td>IPP</td>
<td>20</td>
</tr>
<tr>
<td>Wind</td>
<td>IPP</td>
<td>20</td>
</tr>
</tbody>
</table>

**5.3.2 PROPERTY TAX AND INSURANCE**

Property taxes and insurance are an additional important consideration in the cost of new generation; however, these expenses are not treated in a uniform manner among the sources surveyed. Many sources that estimate costs of
renewable technologies include these costs in fixed O&M; in contrast, many estimates of fixed O&M for thermal plants exclude this expense. For consistency, E3 has attempted to develop recommendations for fixed O&M costs that represent only the actual cost of operating and maintaining a plant so that property tax and insurance can be evaluated independently for each technology.

The specific nuances of state and local tax codes which affect the property tax that a plant sited in a particular location are beyond the scope of this analysis. Rather, E3 has chosen a reasonably representative property tax assessment framework whereby property taxes are assessed annually at a rate of 1% per year based on the remaining value of the plant. For simplicity, this is calculated assuming straight-line asset depreciation.

Similarly, E3 uses a relatively simple assumption to derive an estimate of the insurance cost for a plant. Annual insurance is calculated as 0.5% of the initial capital cost and escalates at 2% per year.

5.3.3 FEDERAL TAX POLICY

The federal tax code currently provides three major incentives for new generation:

+ **Accelerated Depreciation:** Eligible renewable technologies are permitted to claim tax benefits associated with depreciation of capital on an accelerated basis through the Modified Accelerated Cost Recovery System (MACRS). Concentrating these tax benefits during the early years of a project’s financing life reduces its levelized costs. The appropriate MACRS schedule by which these benefits accrue varies by
technology. This benefit has no sunset date and hence is assumed to continue indefinitely.

+ **Production Tax Credit (PTC):** Eligible renewable technologies can claim a tax credit based on the amount of generation produced during the first ten years of the project’s life. The credit varies by technology and expired at the end of 2013. Projects online before these sunsets can claim the PTC for the full ten-year horizon.

+ **Investment Tax Credit (ITC):** Eligible technologies can claim a tax credit equal to 30% of applicable capital costs. This credit is currently scheduled to expire at the end of 2016, at which point it would revert to a credit of 10% that is part of the tax code and has no sunset date.

The eligibility of each technology for these tax credits/benefits according to the current tax code is summarized in Table 38.
Table 38. Federal tax credits and benefits available to resources installed in 2013.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Production Tax Credita [$/MWh]</th>
<th>Investment Tax Credit [%]</th>
<th>MACRS [yrs]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Battery</td>
<td></td>
<td></td>
<td>15</td>
</tr>
<tr>
<td>Biogas</td>
<td>$11</td>
<td></td>
<td>10</td>
</tr>
<tr>
<td>Biomass</td>
<td>$23</td>
<td></td>
<td>10</td>
</tr>
<tr>
<td>Coal – PC</td>
<td></td>
<td></td>
<td>20</td>
</tr>
<tr>
<td>Coal – IGCC</td>
<td></td>
<td></td>
<td>20</td>
</tr>
<tr>
<td>CHP</td>
<td></td>
<td></td>
<td>10</td>
</tr>
<tr>
<td>Gas – CCGT</td>
<td></td>
<td></td>
<td>20</td>
</tr>
<tr>
<td>Gas – CT</td>
<td></td>
<td></td>
<td>20</td>
</tr>
<tr>
<td>Geothermal</td>
<td>$23</td>
<td>10%</td>
<td>5</td>
</tr>
<tr>
<td>Hydro – Pumped Storage</td>
<td></td>
<td></td>
<td>30</td>
</tr>
<tr>
<td>Hydro – Large</td>
<td>$11</td>
<td></td>
<td>20</td>
</tr>
<tr>
<td>Hydro – Small</td>
<td>$11</td>
<td></td>
<td>20</td>
</tr>
<tr>
<td>Nuclear</td>
<td></td>
<td></td>
<td>20</td>
</tr>
<tr>
<td>Reciprocating Engine</td>
<td></td>
<td></td>
<td>20</td>
</tr>
<tr>
<td>Solar Thermal</td>
<td></td>
<td>30%</td>
<td>5</td>
</tr>
<tr>
<td>Solar PV</td>
<td></td>
<td>30%</td>
<td>5</td>
</tr>
<tr>
<td>Wind</td>
<td>$23</td>
<td></td>
<td>5</td>
</tr>
</tbody>
</table>

a The production tax credit applies to all generation during the first ten years of a project’s operation.
5.4 Resource Cost Vintages

The expiration of federal tax credits is one among several factors that will cause the cost of renewable development to change in the future. E3 has identified five major factors that would contribute to such differences:

- **Sunset of federal tax credits.** As currently legislated, the federal investment and production tax credits will expire in the coming years: projects that did not begin construction before the close of 2013 will not be able to claim the PTC, and beginning in 2017 the ITC for technologies will revert to 10% of capital costs.

- **Expiration of bonus MACRS.** Plants installed before the close of 2013 were eligible to claim bonus depreciation, allowing the developers to depreciate half of the plant’s full value in the first year for the purposes of a tax deduction. This incentive is no longer available.

- **Expiration of local incentives.** Many states and localities currently offer specific incentives for renewable development that will eventually expire. One notable example is the property tax exemption for solar technologies in California: plants installed before 2017 are exempt from property tax. The expiration of such incentives will put upward pressure on the costs of renewables.

- **Increased cost of capital.** In part, the low costs at which renewable development has occurred can be attributed to the low interest rate environment, which has enabled developers’ access to low cost debt and equity. Provided interest rates eventually return to long-run levels, this favorable financing is unlikely to be available to developers and utilities indefinitely.

- **Reductions in capital cost.** As nascent technologies continue to evolve, improvements in technology may yield cost reductions that would
translate to lower costs for the ratepayer. This factor could offset a portion of the cost increases that will result from the other changes.

To illustrate the potential impacts of such changes, E3 has reevaluated the benchmark wind and solar PV PPA prices presented earlier using assumptions that those resources are built in 2024 instead of 2013; the results are shown in Figure 18 and Figure 19.
Figure 18. Changes in the solar PV benchmark PPA price resulting in changes to tax credits, cost of capital, and capital costs between 2013 and 2024.

<table>
<thead>
<tr>
<th>Event</th>
<th>2013 Price</th>
<th>2024 Price</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expiration of Bonus MACRS (2013)</td>
<td>$88</td>
<td>$124</td>
<td>+$36</td>
</tr>
<tr>
<td>Increased Cost of Capital</td>
<td>+$4</td>
<td>+$12</td>
<td>+$8</td>
</tr>
<tr>
<td>Sunset of 30% ITC (2017)</td>
<td>+$39</td>
<td>+$81</td>
<td>+$42</td>
</tr>
</tbody>
</table>

Figure 19. Changes in the wind benchmark PPA price resulting in changes to tax credits, cost of capital, and capital costs between 2013 and 2024.

<table>
<thead>
<tr>
<th>Event</th>
<th>2013 Price</th>
<th>2024 Price</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expiration of Bonus MACRS (2013)</td>
<td>$34</td>
<td>$62</td>
<td>+$28</td>
</tr>
<tr>
<td>Increased Cost of Capital</td>
<td>+$2</td>
<td>+$4</td>
<td>+$2</td>
</tr>
<tr>
<td>Sunset of PTC (2017)</td>
<td>-$25</td>
<td>-$3</td>
<td>-$22</td>
</tr>
</tbody>
</table>

Levelized Cost of Energy (2014 $/MWh)
Because of the evolving nature of some resources’ capital costs and the transitory nature of the federal tax credits, the cost to ratepayers to construct a new plant will depend upon the timing of the plant’s construction. Since neither of WECC’s studies evaluates the detailed year-by-year investment cycles that will occur between the present day and the snapshot years studied, E3 recommends developing cost inputs for the 10- and 20-year transmission plans based on a single representative vintage.

E3 anticipates that a large share of the renewable development that occurs over the time horizon considered in the 10-year study will take place during the early half of the decade, expedited by the prospect that the ITC and PTC may not be renewed. Therefore, when considering investment decisions over the course of this time horizon, it is appropriate to use a cost corresponding to a vintage not far in the future; 2019 is a reasonable choice for this.

**Figure 20. Recommended installation cost vintage for Reference Case 10-year study.**

**Recommendation:**

+ In the 10-year study cycle, evaluate 2024 resource costs based on capital costs of a plant installed in 2019.

In the context of the 20-year study, there is considerably more uncertainty as to the timing of renewable resource additions; with such uncertainty, E3 recommends using a vintage corresponding to the midpoint of the second decade of analysis (2029). This vintage would be used for projects developed between 2024 and 2034; for projects with online dates in 2024 or before, E3 recommends continuing to use the 2019 capital costs.
Figure 21. Recommended installation cost vintage for Reference Case 20-year study.

**Recommendation:**

+ In the 20-year study cycle, evaluate 2034 resource costs based on capital costs of a plant installed in 2029.
6 Summary of Capital Cost Recommendations

This section provides a summary of E3’s current capital cost recommendations for WECC’s 10- and 20- year studies. The recommendations for the 10-year study, shown in Table 39 on the subsequent page, represent the expected capital costs for plants installed in 2019. The recommendations for the 20-year study (Table 40) capture the expected capital costs for a plant installed in 2029, midway through the second decade of the 20-year horizon. Capital costs in both tables are expressed in 2014 dollars and relative to the plant’s AC nameplate capacity.
### 6.1 10-year Study

Table 39. Recommended capital cost inputs to the 10-year study.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Subtypes</th>
<th>Present-Day [$/kW-ac]</th>
<th>10-Year Recommendation* [$/kW-ac]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Battery</td>
<td></td>
<td>$4,500</td>
<td>$4,500</td>
</tr>
<tr>
<td>Biogas</td>
<td>Landfill</td>
<td>$2,800</td>
<td>$2,800</td>
</tr>
<tr>
<td></td>
<td>Other</td>
<td>$5,600</td>
<td>$5,600</td>
</tr>
<tr>
<td>Biomass</td>
<td></td>
<td>$4,300</td>
<td>$4,300</td>
</tr>
<tr>
<td>Coal</td>
<td>PC</td>
<td>$3,700</td>
<td>$3,700</td>
</tr>
<tr>
<td></td>
<td>IGCC w/ CCS</td>
<td>$8,200</td>
<td>$8,200</td>
</tr>
<tr>
<td>Combined Heat &amp; Power</td>
<td>Small (&lt;5 MW)</td>
<td>$3,800</td>
<td>$3,800</td>
</tr>
<tr>
<td></td>
<td>Large (&gt;5 MW)</td>
<td>$1,650</td>
<td>$1,650</td>
</tr>
<tr>
<td>Gas CCGT</td>
<td>Basic, Wet Cooled</td>
<td>$1,125</td>
<td>$1,125</td>
</tr>
<tr>
<td></td>
<td>Advanced, Wet Cooled</td>
<td>$1,225</td>
<td>$1,225</td>
</tr>
<tr>
<td></td>
<td>Basic, Dry Cooled</td>
<td>$1,200</td>
<td>$1,200</td>
</tr>
<tr>
<td></td>
<td>Advanced, Dry Cooled</td>
<td>$1,300</td>
<td>$1,300</td>
</tr>
<tr>
<td>Gas CT</td>
<td>Aeroderivative</td>
<td>$1,200</td>
<td>$1,200</td>
</tr>
<tr>
<td></td>
<td>Frame</td>
<td>$825</td>
<td>$825</td>
</tr>
<tr>
<td>Geothermal</td>
<td>Binary/Flash</td>
<td>$5,900</td>
<td>$5,900</td>
</tr>
<tr>
<td></td>
<td>Enhanced (EGS)</td>
<td>$10,000</td>
<td>$10,000</td>
</tr>
<tr>
<td>Hydro</td>
<td>Small</td>
<td>$4,000</td>
<td>$4,000</td>
</tr>
<tr>
<td></td>
<td>Large</td>
<td>$3,200</td>
<td>$3,200</td>
</tr>
<tr>
<td></td>
<td>Pumped Storage</td>
<td>$2,400</td>
<td>$2,400</td>
</tr>
<tr>
<td>Nuclear</td>
<td></td>
<td>$8,000</td>
<td>$8,000</td>
</tr>
<tr>
<td>Reciprocating Engine</td>
<td></td>
<td>$1,300</td>
<td>$1,300</td>
</tr>
<tr>
<td>Solar PV</td>
<td>Residential Rooftop</td>
<td>$5,280</td>
<td>$4,357</td>
</tr>
<tr>
<td></td>
<td>Commercial Rooftop</td>
<td>$4,560</td>
<td>$3,786</td>
</tr>
<tr>
<td></td>
<td>Fixed Tilt (1-20 MW)</td>
<td>$3,640</td>
<td>$3,265</td>
</tr>
<tr>
<td></td>
<td>Tracking (1-20 MW)</td>
<td>$3,900</td>
<td>$3,479</td>
</tr>
<tr>
<td></td>
<td>Fixed Tilt (&gt; 20 MW)</td>
<td>$3,080</td>
<td>$2,783</td>
</tr>
<tr>
<td></td>
<td>Tracking (&gt; 20 MW)</td>
<td>$3,380</td>
<td>$3,031</td>
</tr>
<tr>
<td>Solar Thermal</td>
<td>No Storage</td>
<td>$5,500</td>
<td>$4,620</td>
</tr>
<tr>
<td></td>
<td>Six Hour Storage</td>
<td>$8,000</td>
<td>$6,730</td>
</tr>
<tr>
<td>Wind</td>
<td>Onshore</td>
<td>$2,100</td>
<td>$2,000</td>
</tr>
<tr>
<td></td>
<td>Offshore</td>
<td>$6,300</td>
<td>$6,010</td>
</tr>
</tbody>
</table>
### 6.2 20-year Study

**Table 40. Recommended capital cost inputs to the 20-year study.**

<table>
<thead>
<tr>
<th>Technology</th>
<th>Subtypes</th>
<th>Present-Day [$/kW-ac]</th>
<th>20-Year Recommendation [$/kW-ac]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Battery</td>
<td></td>
<td>$4,500</td>
<td>$4,500</td>
</tr>
<tr>
<td>Biogas</td>
<td>Landfill</td>
<td>$2,800</td>
<td>$2,800</td>
</tr>
<tr>
<td></td>
<td>Other</td>
<td>$5,600</td>
<td>$5,600</td>
</tr>
<tr>
<td>Biomass</td>
<td></td>
<td>$4,300</td>
<td>$4,300</td>
</tr>
<tr>
<td>Coal</td>
<td>PC</td>
<td>$3,700</td>
<td>$3,700</td>
</tr>
<tr>
<td></td>
<td>IGCC w/ CCS</td>
<td>$8,200</td>
<td>$8,200</td>
</tr>
<tr>
<td>Combined Heat &amp; Power</td>
<td>Small (&lt;5 MW)</td>
<td>$3,800</td>
<td>$3,800</td>
</tr>
<tr>
<td></td>
<td>Large (&gt;5MW)</td>
<td>$1,650</td>
<td>$1,650</td>
</tr>
<tr>
<td>Gas CCGT</td>
<td>Basic, Wet Cooled</td>
<td>$1,125</td>
<td>$1,125</td>
</tr>
<tr>
<td></td>
<td>Advanced, Wet Cooled</td>
<td>$1,225</td>
<td>$1,225</td>
</tr>
<tr>
<td></td>
<td>Basic, Dry Cooled</td>
<td>$1,200</td>
<td>$1,200</td>
</tr>
<tr>
<td></td>
<td>Advanced, Dry Cooled</td>
<td>$1,300</td>
<td>$1,300</td>
</tr>
<tr>
<td>Gas CT</td>
<td>Aeroderivative</td>
<td>$1,200</td>
<td>$1,200</td>
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<tr>
<td></td>
<td>Frame</td>
<td>$825</td>
<td>$825</td>
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<tr>
<td>Geothermal</td>
<td>Binary/Flash</td>
<td>$5,900</td>
<td>$5,900</td>
</tr>
<tr>
<td></td>
<td>Enhanced (EGS)</td>
<td>$10,000</td>
<td>$10,000</td>
</tr>
<tr>
<td>Hydro</td>
<td>Small</td>
<td>$4,000</td>
<td>$4,000</td>
</tr>
<tr>
<td></td>
<td>Large</td>
<td>$3,200</td>
<td>$3,200</td>
</tr>
<tr>
<td></td>
<td>Pumped Storage</td>
<td>$2,400</td>
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</tr>
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<td>Nuclear</td>
<td></td>
<td>$8,000</td>
<td>$8,000</td>
</tr>
<tr>
<td>Reciprocating Engine</td>
<td></td>
<td>$1,300</td>
<td>$1,300</td>
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<td>Solar PV</td>
<td>Residential Rooftop</td>
<td>$5,280</td>
<td>$3,684</td>
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<td>Commercial Rooftop</td>
<td>$4,560</td>
<td>$3,200</td>
</tr>
<tr>
<td></td>
<td>Fixed Tilt (1-20 MW)</td>
<td>$3,640</td>
<td>$2,874</td>
</tr>
<tr>
<td></td>
<td>Tracking (1-20 MW)</td>
<td>$3,900</td>
<td>$3,071</td>
</tr>
<tr>
<td></td>
<td>Fixed Tilt (&gt; 20 MW)</td>
<td>$3,080</td>
<td>$2,440</td>
</tr>
<tr>
<td></td>
<td>Tracking (&gt; 20 MW)</td>
<td>$3,380</td>
<td>$2,668</td>
</tr>
<tr>
<td>Solar Thermal</td>
<td>No Storage</td>
<td>$5,500</td>
<td>$4,110</td>
</tr>
<tr>
<td></td>
<td>Six Hour Storage</td>
<td>$8,000</td>
<td>$5,980</td>
</tr>
<tr>
<td>Wind</td>
<td>Onshore</td>
<td>$2,100</td>
<td>$1,920</td>
</tr>
<tr>
<td></td>
<td>Offshore</td>
<td>$6,300</td>
<td>$5,760</td>
</tr>
</tbody>
</table>
7 Sources

7.1 References


7.2 Survey Sources & Cost Adjustments

This section presents a summary of the studies that provided technology cost estimates that were included in E3’s review, as well as the cost adjustments made to each study to allow for side-by-side comparison of the studies. Table 41 provides a comprehensive listing of the studies under the same abbreviated study names that are used in the capital cost tables. Each study’s reported results were converted to 2014 dollars from the cost basis year reported in the table below using the inflation adjustments in Table 43. For sources that provided only overnight capital costs, E3 multiplied these estimates by assumed interest-during-construction (IDC) adjustments calculated based on the assumed WACC and construction schedules, most of which were based on the CEC’s Cost of Generation model. These assumed capital cost adjustments are shown in Table 42.

---

2 E3’s IDC adjustments correspond closely to the CEC’s allowance for funds used during construction (AFUDC) multipliers with one exception: for coal technologies, the CEC’s construction schedule is a single year; E3 has used
Table 41. Studies included in the survey of generation capital costs & applicability of inflation/IDC adjustments to each.

<table>
<thead>
<tr>
<th>Study</th>
<th>Author</th>
<th>Cost Basis Year</th>
<th>Cost Basis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alta Rock</td>
<td>AltaRock Energy (2010)</td>
<td>2010</td>
<td>All-in</td>
</tr>
<tr>
<td>APS IRP</td>
<td>APS (2012)</td>
<td>2011</td>
<td>Overnight</td>
</tr>
<tr>
<td>Arizona Goes Solar</td>
<td>Arizona Goes Solar (APS)</td>
<td>2013</td>
<td>All-in</td>
</tr>
<tr>
<td>(APS)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Avista IRP</td>
<td>Avista (2013)</td>
<td>2014</td>
<td>All-in</td>
</tr>
<tr>
<td>B&amp;V/NREL</td>
<td>B&amp;V (2012)</td>
<td>2009</td>
<td>Overnight</td>
</tr>
<tr>
<td>California Solar</td>
<td>California Solar Statistics</td>
<td>2013</td>
<td>All-in</td>
</tr>
<tr>
<td>Initiative</td>
<td>(2014)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CEC 2013</td>
<td>CEC (2013)</td>
<td>2013</td>
<td>All-in</td>
</tr>
<tr>
<td>CEC 2009</td>
<td>Klein, J. (2009)</td>
<td>2009</td>
<td>All-in</td>
</tr>
<tr>
<td>CPUC (LTPP)</td>
<td>CPUC (2010)</td>
<td>2010</td>
<td>All-in</td>
</tr>
<tr>
<td>CPUC</td>
<td>CPUC (2012)</td>
<td>2010</td>
<td>All-in</td>
</tr>
<tr>
<td>CSIRO</td>
<td>Hinkley, J., et al. (2011)</td>
<td>2010</td>
<td>Overnight</td>
</tr>
<tr>
<td>DOE Sunshot</td>
<td>DOE (2012)</td>
<td>2010</td>
<td>All-in</td>
</tr>
<tr>
<td>Eagle Mountain</td>
<td>Eagle Crest (2014)</td>
<td>2014</td>
<td>All-in</td>
</tr>
<tr>
<td>EIA</td>
<td>EIA (2013)</td>
<td>2012</td>
<td>Overnight</td>
</tr>
<tr>
<td>EPRI 2010</td>
<td>EPRI (2010)</td>
<td>2008</td>
<td>All-in</td>
</tr>
<tr>
<td>EPRI 2013A</td>
<td>EPRI (2013a)</td>
<td>2011</td>
<td>All-in</td>
</tr>
<tr>
<td>EPRI 2013B</td>
<td>EPRI (2013b)</td>
<td>2010</td>
<td>All-in</td>
</tr>
<tr>
<td>HDR</td>
<td>HDR Engineering (2011)</td>
<td>2012</td>
<td>All-in</td>
</tr>
<tr>
<td>ICF</td>
<td>Hedman et al. (2012)</td>
<td>2011</td>
<td>All-in</td>
</tr>
<tr>
<td>Idaho Power IRP</td>
<td>Idaho Power (2013)</td>
<td>2013</td>
<td>All-in</td>
</tr>
<tr>
<td>IRENA 2012A</td>
<td>IRENA (2012a)</td>
<td>2012</td>
<td>All-in</td>
</tr>
<tr>
<td>IRENA 2012B</td>
<td>IRENA (2012b)</td>
<td>2010</td>
<td>All-in</td>
</tr>
<tr>
<td>IRENA 2013</td>
<td>IRENA (2013)</td>
<td>2012</td>
<td>All-in</td>
</tr>
<tr>
<td>Lazard</td>
<td>Lazard (2013)</td>
<td>2013</td>
<td>All-in</td>
</tr>
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</table>

longer time horizons (five and six years for PC and IGCC w/ CCS, respectively) to calculate appropriate adjustments.
<table>
<thead>
<tr>
<th>Source</th>
<th>Methodology</th>
<th>Year</th>
<th>Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>LBNL (TTS)</td>
<td>Barbose et al. (2013)</td>
<td>2012</td>
<td>All-in</td>
</tr>
<tr>
<td>LBNL (WTMR)</td>
<td>Wiser and Bolinger (2013)</td>
<td>2012</td>
<td>All-in</td>
</tr>
<tr>
<td>NREL 2012</td>
<td>Goodrich, A., et al. (2012)</td>
<td>2010</td>
<td>All-in</td>
</tr>
<tr>
<td>NREL 2011</td>
<td>Augustine, C. (2011)</td>
<td>2008</td>
<td>All-in</td>
</tr>
<tr>
<td>NV Energy Rebate Program</td>
<td>NV Energy (2014)</td>
<td>2013</td>
<td>All-in</td>
</tr>
<tr>
<td>NW PCC</td>
<td>NW PCC (2010)</td>
<td>2006</td>
<td>Overnight</td>
</tr>
<tr>
<td>PacifiCorp IRP</td>
<td>PacifiCorp (2013)</td>
<td>2012</td>
<td>All-in</td>
</tr>
<tr>
<td>PGE IRP</td>
<td>PGE (2013)</td>
<td>2012</td>
<td>Overnight</td>
</tr>
<tr>
<td>PNM IRP</td>
<td>PNM (2011)</td>
<td>2011</td>
<td>All-in</td>
</tr>
<tr>
<td>Sandia 2013</td>
<td>Akhil, A., et al. (2013)</td>
<td>2011</td>
<td>All-in</td>
</tr>
<tr>
<td>Sandia 2011</td>
<td>Kolb, G., et al. (2011)</td>
<td>2010</td>
<td>All-in</td>
</tr>
<tr>
<td>SEIA/GTM</td>
<td>SEIA/GTM (2013)</td>
<td>2013</td>
<td>All-in</td>
</tr>
<tr>
<td>Southern Company</td>
<td>Southern Company (2014)</td>
<td>2013</td>
<td>All-in</td>
</tr>
<tr>
<td>SPV Market Research</td>
<td>SPV (2013)</td>
<td>2013</td>
<td>All-in</td>
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<tr>
<td>TEP IRP</td>
<td>TEP (2012)</td>
<td>2012</td>
<td>All-in</td>
</tr>
<tr>
<td>WEC/BNEF</td>
<td>WEC/BNEF (2013)</td>
<td>2013</td>
<td>All-in</td>
</tr>
<tr>
<td>WREZ 3.0 (B&amp;V)</td>
<td>B&amp;V (2013)</td>
<td>2013</td>
<td>All-in</td>
</tr>
<tr>
<td>Xcel IRP</td>
<td>Xcel Energy (2011)</td>
<td>2011</td>
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Table 42. Assumed IDC adjustments used to translate cost estimates from sources that provided overnight capital costs to all-in costs.

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<tr>
<th>Technology</th>
<th>Subtype</th>
<th>IDC Adjustment</th>
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<tr>
<td>Battery</td>
<td></td>
<td>100.0%</td>
</tr>
<tr>
<td>Biogas</td>
<td></td>
<td>105.9%</td>
</tr>
<tr>
<td>Biomass</td>
<td></td>
<td>105.9%</td>
</tr>
<tr>
<td>Coal</td>
<td>PC</td>
<td>121.0%</td>
</tr>
<tr>
<td></td>
<td>IGCC w/ CCS</td>
<td>125.8%</td>
</tr>
<tr>
<td>Combined Heat &amp; Power</td>
<td></td>
<td>103.5%</td>
</tr>
<tr>
<td>Gas CCGT</td>
<td></td>
<td>106.8%</td>
</tr>
<tr>
<td>Gas CT</td>
<td></td>
<td>103.5%</td>
</tr>
<tr>
<td>Geothermal</td>
<td></td>
<td>111.4%</td>
</tr>
<tr>
<td>Hydro</td>
<td>Pumped Storage</td>
<td>108.0%</td>
</tr>
<tr>
<td></td>
<td>Large</td>
<td>108.0%</td>
</tr>
<tr>
<td></td>
<td>Small</td>
<td>104.1%</td>
</tr>
<tr>
<td>Nuclear</td>
<td></td>
<td>151.5%</td>
</tr>
<tr>
<td>Reciprocating Engine</td>
<td></td>
<td>103.5%</td>
</tr>
<tr>
<td>Solar PV</td>
<td>Residential Rooftop</td>
<td>100.0%</td>
</tr>
<tr>
<td></td>
<td>Commercial Rooftop</td>
<td>100.0%</td>
</tr>
<tr>
<td></td>
<td>Distributed Utility (Fixed Tilt)</td>
<td>104.6%</td>
</tr>
<tr>
<td></td>
<td>Distributed Utility (Tracking)</td>
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</tr>
<tr>
<td></td>
<td>Large Utility (Fixed Tilt)</td>
<td>104.6%</td>
</tr>
<tr>
<td></td>
<td>Large Utility (Tracking)</td>
<td>104.6%</td>
</tr>
<tr>
<td>Solar Thermal</td>
<td>No Storage</td>
<td>104.6%</td>
</tr>
<tr>
<td></td>
<td>Six Hour Storage</td>
<td>104.6%</td>
</tr>
<tr>
<td>Wind</td>
<td></td>
<td>104.9%</td>
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Table 43. Consumer Price Index (CPI) factors used to translate capital cost estimates to 2010 dollars.

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<tr>
<td>2006</td>
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<tr>
<td>2007</td>
<td>207.3</td>
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<tr>
<td>2008</td>
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<td>2011</td>
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<td>2012</td>
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<tr>
<td>2013</td>
<td>233.5</td>
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<tr>
<td>2014</td>
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