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An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes

Andrew Mills and Ryan Wiser

Environmental Energy Technologies Division

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Abstract

As renewable technologies mature, recognizing and evaluating their economic value will become increasingly important for justifying their expanded use. This report reviews a recent sample of U.S. load-serving entity (LSE) planning studies and procurement processes to identify how current practices reflect the drivers of solar's economic value. In particular, we analyze the LSEs' treatment of the capacity value, energy value, and integration costs of solar energy; the LSEs' treatment of other factors including the risk reduction value of solar, impacts to the transmission and distribution system, and options that might mitigate solar variability and uncertainty; the methods LSEs use to design candidate portfolios of resources for evaluation within the studies; and the approaches LSEs use to evaluate the economic attractiveness of bids during procurement.

We found that many LSEs have a framework to capture and evaluate solar's value, but approaches varied widely: only a few studies appeared to complement the framework with detailed analysis of key factors such as capacity credits, integration costs, and tradeoffs between distributed and utility-scale photovoltaics. Full evaluation of the costs and benefits of solar requires that a variety of solar options are included in a diverse set of candidate portfolios. The design of candidate portfolios evaluated in the studies, particularly regarding the methods used to rank potential resource options, can be improved. We found that studies account for the capacity value of solar, though capacity credit estimates with increasing penetration can be improved. Furthermore, while most LSEs have the right approach and tools to evaluate the energy value of solar, improvements remain possible, particularly in estimating solar integration costs used to adjust energy value. Transmission and distribution benefits, or costs, related to solar are rarely included in studies. Similarly, few LSE planning studies can reflect the full range of potential benefits from adding thermal storage and/or natural gas augmentation to concentrating solar power plants. Finally, the level of detail provided in requests for proposals used in procurement is not always sufficient for bidders to identify the most valuable technology or configurations to the LSE.

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Acronyms and Abbreviations

APS	Arizona Public Service
AS	Ancillary service
CA IOU	California Investor-Owned Utility
CAISO	California Independent System Operator
CCGT	Combined cycle gas turbine
CPUC	California Public Utilities Commission
CSP	Concentrating solar power
CT	Combustion turbine
DG	Distributed generation
ELCC	Effective load-carrying capability
IID	Imperial Irrigation District
IRP	Integrated resource plan
LADWP	Los Angeles Department of Water and Power
LCBF	Least-cost, best-fit
LOLP	Loss of load probability
LSE	Load-serving entity
LTPP	Long-Term Procurement Plan
NGST	Natural gas steam turbine
NPCC	Northwest Power and Conservation Council
NQC	Net qualifying capacity
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
PG&E	Pacific Gas and Electric
PGE	Portland General Electric
PNM	Public Service of New Mexico
PPA	Power purchase agreement
PSCo	Public Service of Colorado
PV	Photovoltaics
PVRR	Present value of the revenue requirement
RA	Resource adequacy
REC	Renewable energy certificate
RETI	Renewable Energy Transmission Initiative
RFP	Request for proposals
RPS	Renewables portfolio standard
SCPPA	Southern California Public Power Authority
SEPA	Solar Electric Power Association
T&D	Transmission and distribution
TEP	Tucson Electric Power
TWh	Terawatt-hour
WECC	Western Electricity Coordinating Council
WREZ	Western Renewable Energy Zone Initiative

Executive Summary

Introduction

Recent declines in the cost of photovoltaic (PV) energy, increasing experience with the deployment of concentrating solar power (CSP), the availability of tax-based incentives for solar, and state renewables portfolio standards (RPS) (some with solar-specific requirements) have led to increased interest in solar power among U.S. load-serving entities (LSEs). This interest is reflected within LSE planning and procurement processes and in a growing body of literature on the economic value of solar energy within utility portfolios. This report identifies how current LSE planning and procurement practices reflect the drivers of solar's economic value identified in the broader literature. This comparison can help LSEs, regulators, and policy makers identify ways to improve LSE planning and procurement.

The report reviews 16 planning studies and nine documents describing procurement processes created during 2008–2012 by LSEs interested in solar power (Table ES1). We first summarize the typical approach used by LSEs in planning studies and procurement processes. We then analyze the LSEs' treatment of the capacity value, energy value, and integration costs of solar energy; the LSEs' treatment of other factors including the risk reduction value of solar, impacts to the transmission and distribution system, and options that might mitigate solar variability and uncertainty; the methods LSEs use to design candidate portfolios of resources for evaluation within the studies; and the approaches LSEs use to evaluate the economic attractiveness of bids during procurement. We offer several recommendations that could help LSEs improve planning studies and procurement processes.

Table ES1. Planning studies and procurement practices reviewed in this analysis

Load-serving entity or study author	Planning study (year)	Procurement practices (year)
Arizona Public Service	2012	2011
California IOU Process	2010	2011
Duke Energy Carolinas	2011	-
El Paso Electric	2012	2011
Idaho Power	2011	-
Imperial Irrigation District	2010	-
Los Angeles Department of Water and Power	2011	2012
Northwest Power and Conservation Council	2010	-
NV Energy	2012	2010
PacifiCorp	2011	2010
Portland General Electric	2009	2012
Public Service of Colorado	2011	2011
Public Service of New Mexico	2011	2011
Salt River Project	2010	-
Tri-State Generation and Transmission	2010	-
Tucson Electric Power	2012	-

Summary of steps used by LSEs in planning studies and procurement processes

Many of the LSEs followed a similar set of steps that began with an assessment of demand forecasts, generation options, fuel price forecasts, and regulatory requirements over a planning horizon. Based on this assessment, LSEs created candidate resource portfolios that satisfy these needs and regulatory requirements. These candidate portfolios were typically created using one of three methods:

- Manual creation based on engineering judgment or stakeholder requests
- Creation using capacity-expansion models based on deterministic future assumptions
- Creation using an intermediate approach in which resource options are ranked according to metrics defined by each LSE

The present value of the revenue requirement (PVRR) of candidate portfolios was then evaluated in detail. The PVRR of each portfolio was based primarily on the capital cost of each portfolio and the variable cost of dispatching each portfolio to maintain a balance between supply and demand over the planning period. The variable cost was commonly evaluated by simulating the dispatch of the portfolio using a production cost model. Many LSEs used scenario analysis or Monte-Carlo analysis (or some combination of both) to evaluate the exposure of each portfolio to changes in uncertain factors such as fossil-fuel prices, demand, or carbon dioxide prices. LSEs then chose a preferred portfolio based on the relative performance of the candidate portfolios. The preferred portfolio was often determined by balancing a desire for both low costs and low risks. During procurement, LSEs often solicited bids for resources that matched the characteristics of resources identified in the preferred portfolio.

Solar technologies considered in planning and procurement

Among our sample, many LSEs considered PV and CSP with or without thermal storage or natural gas augmentation.[1] The PV technologies considered by LSEs were not always described in detail. When they were described, LSEs typically considered fixed PV or single-axis tracking PV; some also distinguished between distributed and utility-scale PV. One LSE considered a PV plant coupled with a lead-acid battery. The CSP technology was usually based on a parabolic trough or a solar power tower configuration. One LSE considered a solar chimney, and another LSE considered a solar thermal gas hybrid (a natural gas power plant with solar concentrators that preheat water used in the plant's steam cycle).

Recognition of solar capacity value in planning studies

In regions where solar generation is well correlated with periods of high demand, one of the main contributors to solar's economic value is the capacity value. The capacity value of solar

[1] Natural gas augmentation is a modification to CSP plants in which the boiler used in the steam cycle can burn natural gas. This allows the CSP plant to operate when insolation is low. The low efficiency of using natural gas in a steam boiler compared with a combined cycle natural gas plant typically means that natural gas augmentation is only used during times when insolation is low and more efficient power plants are already fully deployed.

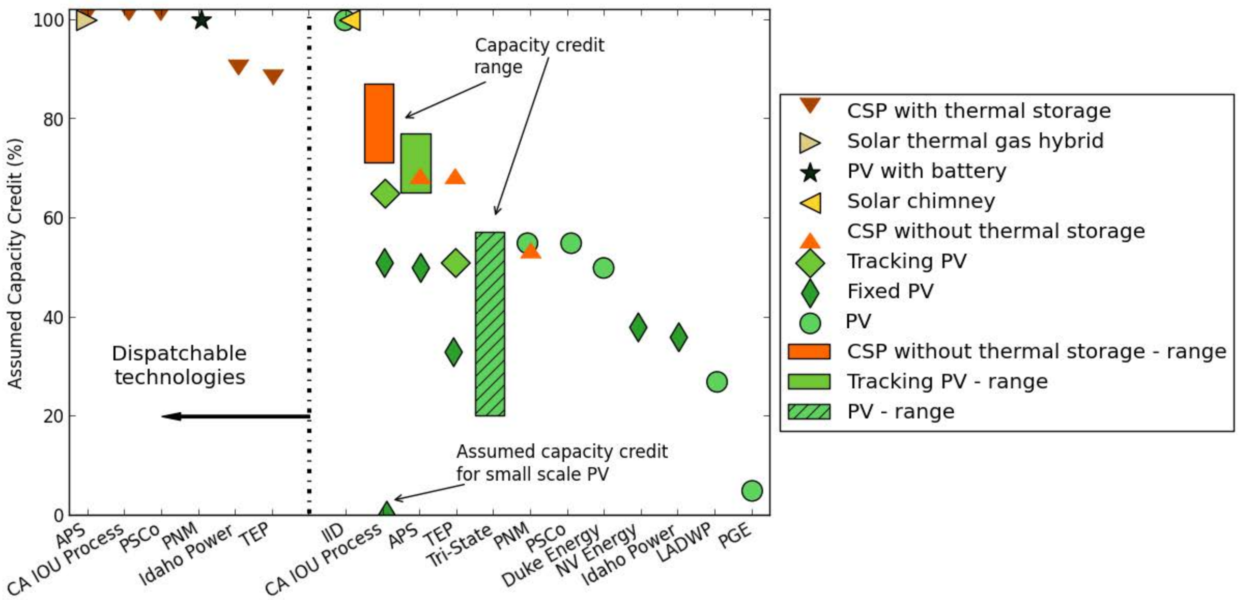
reflects the avoided costs from reducing the need to build other capacity resources, often combustion turbines (CTs), to meet peak demand reliably. LSEs usually added sufficient capacity to meet the peak load plus a planning reserve margin in each candidate portfolio. Portfolios that included solar need not include as much capacity from other resources, so solar offset some of the capital cost that would otherwise be included in the portfolio's PVRR. Thus, solar's capacity value was based in part on the capital cost of the avoided capacity resources and the timing of the need for new capacity.

The capacity value of solar was affected by the study methodology. In at least one case, the LSE assumed that the generating resources used for capacity were very "lumpy" (i.e., only available in blocks of 290 MW or greater). As a result, adding a small amount of solar to a portfolio could not change the timing or amount of other capacity resources required; thus, the same amount of CT capacity was needed with or without the inclusion of solar, even though the LSE recognized that some of the solar nameplate capacity could contribute to meeting peak loads. Including capacity resources that are available in smaller size increments—e.g., 50-MW CTs, which were modeled by other LSEs—or modeling the value of selling excess capacity to neighboring LSEs better recognizes solar's capacity value.

Estimates of solar capacity credit in planning studies and broader literature

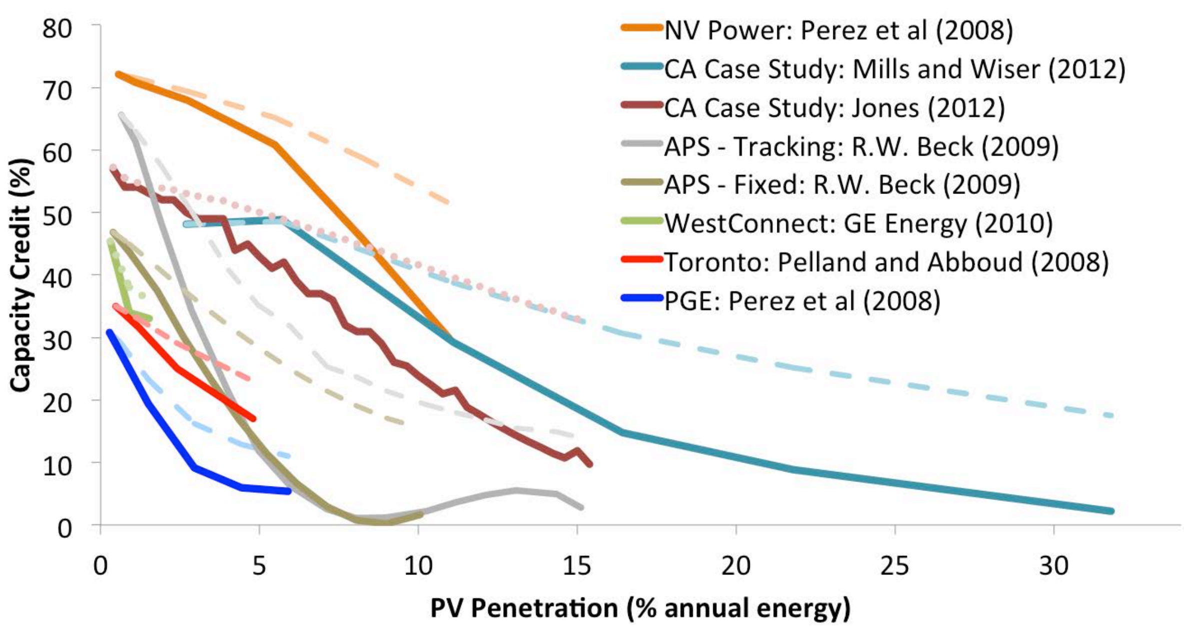
The primary driver of solar's capacity value is the capacity credit: the percentage of the solar nameplate capacity that can be counted toward meeting the peak load and planning reserve margin. The capacity credit assigned to solar technologies by the LSE determines how much capacity from an alternative resource can be avoided by including solar in a portfolio. For example, a capacity credit of 50% for PV indicates that a 100-MW PV plant can contribute roughly the same toward meeting peak load and the planning reserve margin as a 50-MW CT. Analysis in the literature shows that the capacity credit of solar largely depends on the correlation of solar production with LSE demand, meaning the capacity credit varies by solar technology (e.g., PV vs. CSP with thermal storage), configuration (e.g., single-axis tracking PV vs. fixed PV), and LSE (e.g., summer afternoon peaking vs. winter night peaking). As expected, the capacity credit assigned by LSEs to solar in planning studies varied by technology, configuration, and LSE (Figure ES1). However, few studies appeared to use detailed loss of load probability (LOLP) studies to determine the capacity credit of solar. Instead, most LSEs relied on analysis of the solar production during peak-load periods or assumptions based on rules of thumb. The reliance on assumptions or simple approximation methods to assign a capacity credit to solar may also contribute to much of the variation in capacity credit across studies.

Only one LSE, Arizona Public Service, appeared to account for changes in the capacity credit of solar with increasing penetration. Analysis in the broader literature finds that solar capacity credit decreases with increasing solar penetration, particularly for PV and CSP without thermal storage or natural gas augmentation (Figure ES2). One of the main factors in the literature that distinguishes the economic value of CSP with thermal storage from the economic value of PV and CSP without thermal storage or natural gas augmentation is the ability of CSP with thermal storage to maintain a high capacity credit with increasing penetration. If LSE planning studies do not reflect this difference in capacity credit with increasing penetration, then the difference in economic value among different solar technologies will not be reflected in their planning studies.



Note: Imperial Irrigation District (IID) appears to assume a 100% capacity credit for PV and a solar chimney. Capacity credit for APS represent capacity credit applied at low penetration level; capacity credit is reduced with higher PV penetration. Range of capacity credits for APS and CA IOU process are based on different plant locations.

Figure ES1. Capacity credits applied by LSEs in planning studies



See main text for additional notes

Figure ES2. PV capacity credit estimates with increasing penetration levels (dashed line is average capacity credit, solid line is incremental capacity credit)

Given the importance of solar's capacity credit for determining economic value and ensuring reliability, LSEs should consider conducting detailed estimates of solar capacity credit. LSEs considering portfolios with large amounts of solar may also need to account for expected changes in the solar capacity credit with increasing penetration.

Evaluation of the energy value of solar using production cost models

In addition to capacity value, another primary driver of solar's economic value is the energy value. The energy value reflects the reduction in the PVRR from avoiding variable fuel and operational costs from conventional power plants in portfolios with solar. When LSEs evaluate candidate portfolios, they often use production cost models that account for the temporal variation in solar generation, demand, and other resource profiles. Many of the production cost models used by LSEs in planning studies have hourly temporal resolution (either over a one-week period each month or over the full year), and some production cost models account for the various operational constraints of conventional generation. These models appear to account for any benefit from solar generation being correlated with times when plants with high variable costs would otherwise be needed.

The LSEs in our sample that included CSP with thermal storage in candidate portfolios did not describe the approach they used to account for the dispatchability of CSP with thermal storage in the production cost models. In previous analyses, CSP with thermal storage was assumed to operate with a fixed generation profile in which the thermal storage generates as much power as possible in specific, static periods. While this simplified approach may capture some of the benefits of thermal storage, the full benefits to a particular LSE can be better captured by modeling the dispatchability of CSP directly in the production cost model. Compared to thermal storage, natural gas augmentation is relatively easier to model in a production cost model. One LSE described its approach to incorporating natural gas augmentation into its model.

The production cost models used by most LSEs also can account for changes in the energy value as the penetration of solar increases. One key factor in this regard is how LSEs consider the broader wholesale market and the assumptions they make about solar penetration in neighboring markets. If the LSE assumes other regions do not add solar, then selling power to the broader market during times of high insolation and low load may mitigate reductions in the energy value as the penetration of solar increases in the candidate portfolio. Such opportunities may not be available to the same degree, however, if many LSEs in a region simultaneously add solar. LSEs can improve their planning studies by better describing the assumptions and approaches used to account for broader wholesale markets when using production cost models to evaluate candidate portfolios.

Adjusting the energy value to account for integration costs

Many LSEs adjust production cost model assumptions or results to account for solar integration costs. Adjustments make sense when there are factors that cannot be represented in the production cost model owing to data or computational limitations. In that case, the adjustments could be tailored to account for the shortcomings of a specific LSE's modeling approach or production cost model. Two studies accounted for solar integration costs by increasing the operating reserve requirement in the hourly production cost model to account for sub-hourly variability and uncertainty that otherwise would be ignored. The increase in operating reserves was based on a separate detailed analysis of sub-hourly variability and uncertainty of solar, wind, and load. Alternatively, other LSEs directly added an estimated integration cost to the production cost model results depending on the amount of solar included in the candidate portfolio. The integration costs for solar added to the production cost model results ranged from $2.5/MWh to $10/MWh. Of the LSEs that used this approach, only one conducted a detailed study of solar integration costs (based on day-ahead forecast errors). The remaining LSEs relied on assumptions, results from studies in other regions, or integration cost estimates for wind. Based on the scarcity of detailed analysis of solar integration costs and the wide range of integration cost estimates used in the planning studies, more LSEs should consider carefully analyzing solar integration costs for their system (estimating what is not already captured by their modeling approach) to better justify their assumptions.

Additional factors included or excluded from planning studies

Aside from the capacity and energy values, other attributes of solar are often also included in planning studies. The potential risk-reduction benefit of solar, for example, can be accounted for in studies that evaluate the performance of candidate portfolios with and without solar under different assumptions about the future. Transmission and distribution benefits, or costs, related to solar are not often accounted for in LSE studies. In one clear exception, avoided distribution costs were directly accounted for by one LSE in portfolios with distributed PV. In a few other cases, candidate portfolios with solar required less transmission than candidate portfolios with other generation options. The difference in avoided costs between utility-scale solar and distributed PV are not well known, but as more studies provide insight into these differences, LSEs should consider incorporating that information into their planning studies.

A number of LSE planning studies included options that may increase the economic value of solar. Some LSEs included thermal storage or natural gas augmentation with CSP plants, one study considered PV coupled with a lead-acid battery, and another added grid-scale batteries to candidate portfolios with wind and solar (in both cases the additional capital cost of the batteries was too high to reduce the overall PVRR relative to the cases without batteries). Other studies considered a wide range of grid-level storage options without explicitly tying these storage resources to the candidate portfolios with wind or solar. None of the studies appeared to directly consider the role of demand response in increasing the value of solar or directly identify synergies in the capacity credit or integration costs for combinations of wind and solar. Any such synergy in energy value, on the other hand, may have been indirectly accounted for in production cost modeling of candidate portfolios with combinations of wind and solar.

Designing candidate portfolios to use in planning studies

While the overall framework used by many of the LSEs for evaluating candidate portfolios appears to capture many (but not all) solar benefits, one important area for improvement is creating candidate portfolios in the first place. The complex interactions between various resource options and existing generation make it difficult to identify which resource options will be most economically attractive. To manage this complexity, a number of LSEs relied on capacity-expansion models to design candidate portfolios, most of which were based on deterministic assumptions about future costs and needs. The LSEs that did not use capacity-expansion models either manually created candidate portfolios based on engineering judgment or stakeholder input or created candidate portfolios by ranking resource options using simplified criteria.

A logical way to rank resources is to estimate the change in the PVRR of a portfolio from including a particular resource in the portfolio and displacing other resources. This change in PVRR is called the "net cost" of a resource since it represents the difference between the cost of adding the resource and the avoided cost from displacing other resources that are no longer needed to ensure the portfolio can meet reliability and regulatory constraints. Since the goal of many planning studies is to minimize the expected PVRR, the resources with the lowest net cost should be added to the portfolio. LSEs in California used a similar approach to identify renewable resource options that were included in their candidate portfolios.

In contrast, a number of LSEs used the levelized cost of energy of resource options along with various adjustments (often based on capacity and integration cost adjustments) to rank resource options. The adjustments, particularly the capacity adjustments, were often not clearly justified and did not always link back to the broader objective of minimizing the expected PVRR. Based on these findings, we recommend that, where possible, LSEs use capacity-expansion models to build candidate portfolios. Improvements in capacity expansion models to account for factors like risk, uncertainty, dispatchability of CSP plants with thermal storage, and operational constraints for conventional generation may be appropriate for some LSEs. If using a capacity-expansion model to build candidate portfolios is not possible, then an approach like the net cost ranking should be considered instead.

Economic evaluation of bids in procurement processes

Finally, we found that LSE procurement often evaluated the economic attractiveness of bids based on the estimated net cost, but often it was unclear exactly how this net cost was evaluated. The lack of clarity in many procurement documents makes it difficult for a bidder to estimate how various choices it makes in terms of solar technology or configuration will impact the net cost of its bid. The bidder will know how these choices affect the cost side of the bid but often must guess or try to replicate the LSE's planning process to determine how different choices will affect the LSE's avoided costs. LSEs likely could elicit more economically attractive bids by providing as much detail as possible on how the net cost of each bid will be evaluated and the differences in the LSE's avoided costs for different technologies and configurations.

Although this review focused on the valuation of solar in planning and procurement, many of the LSEs are considering other renewable technologies, particularly wind. The lessons learned from this analysis and many of the recommendations apply to the evaluation of other renewable energy options beyond solar.

1. Introduction

With increased worldwide deployment of solar energy technologies, the cost of generating power from photovoltaics (PV) and concentrating solar power (CSP) has decreased and is expected to decrease further (Barbose et al. 2012, Arvizu et al. 2011, EASAC 2011, Chu and Majumdar 2012). As the cost of solar generation falls, load-serving entities (LSEs), regulators, and policy makers increasingly consider solar generation as one of the many viable options for supplying electricity. For an LSE, solar power provides energy and can satisfy some peak electricity demand in place of conventional generation resources (Hoff 1988, Perez et al. 2008, Pelland and Abboud 2008, Madaeni et al. 2012a, Olson and Jones 2012, Mills and Wiser 2012), helps meet state renewables portfolio standard (RPS) targets (Wiser and Barbose 2008; Wiser et al. 2011), reduces exposure to uncertain fossil fuel and carbon dioxide prices (Bokenkamp et al. 2005, Bolinger and Wiser 2009, Denholm et al. 2009, Perez et al. 2011), and provides ancillary services in the case of CSP with thermal storage and/or natural gas augmentation (EASAC 2011, Madaeni et al. 2012b).

Generally, the primary resource-procurement considerations of an LSE include its needs for capacity and energy, regulatory requirements (state and federal), the relative impact of resources on the LSE's revenue requirement, and the impact of the resource options on the LSE's exposure to future cost uncertainty. Regarding the impact on the revenue requirement, the cost of contracting or building a new plant is in part offset by the costs that the new resource allows the LSE to avoid. These avoided costs are sometimes called the "economic value" of a new generation resource.

Detailed estimates of the economic value of solar in previous analyses show that solar can have high economic value at low penetration levels where there is high coincidence of solar generation and periods of high demand (Borenstein 2008, Lamont 2008, R.W. Beck 2009, Sioshansi and Denholm 2010). At least at low penetration, the economic impact of imperfect forecastability and the need for increased ancillary services with solar appear to be secondary to the higher capacity and energy value (EnerNex 2009, Mills and Wiser 2010, Navigant Consulting et al. 2011, Mills and Wiser 2012). In addition, various studies highlight synergistic effects between combinations of renewable generating technologies such as solar and wind (Denholm and Hand 2011, Nagl et al. 2011, Fripp 2012), PV and CSP with thermal storage (Denholm and Mehos 2011), and PV with storage or demand response (Denholm and Margolis 2007).

Detailed studies also show that the economic value of PV and CSP without thermal storage (or natural gas augmentation) decreases with increasing penetration (Olson and Jones 2012, Mills and Wiser 2012). Increased solar penetration reduces the net load during the day, so eventually the period of peak load net of solar generation shifts into the early evening, even where there is high coincidence of load and insolation. Further, on days with relatively lower load, solar will start to displace generation resources with lower variable costs, such as coal (Denholm et al. 2009, Olson and Jones 2012, Mills and Wiser 2012). At low penetration, the addition of 2–4 hours of thermal storage to CSP appears more valuable than CSP without thermal storage

(Madaeni et al. 2012b),[2] although in a separate analysis, CSP plants with 6 hours of thermal storage do not appear to have a significantly greater value (in $/MWh terms) than other solar technologies (Mills and Wiser 2012). On the other hand, the benefit of thermal storage is clear at high penetrations (above about 10% penetration on an annual energy basis) because it helps avoid the otherwise significant decline in value of solar with increasing solar penetration (Mills and Wiser 2012).

This report investigates whether the understanding of solar's economic value from the research literature is reflected in the treatment of solar options in LSE planning studies and procurement processes.[3] We compare methods used by different LSEs, primarily located in the Western and Southern United States. Where possible, we also highlight potential improvements that LSEs (or regulators that oversee them) could make to current planning and procurement methodologies to better reflect the economic value of solar.[4] In particular, we focus on the methods for representing the capacity value,[5] energy value, costs associated with day-ahead forecast errors and ancillary services, and various other factors including transmission and distribution system impacts, measures that might mitigate solar variability and uncertainty and portfolio risk reduction. Although these attributes are not necessarily uniquely identified for solar in LSE planning studies, organizing the discussion around these attributes helps illuminate the many drivers that ultimately affect the attractiveness of resource portfolios that include solar. We also look for indications that LSEs are considering attributes that might increase the value of solar, such as PV tracking, CSP with thermal storage and natural gas augmentation, or synergistic interactions between multiple technologies like PV and CSP or solar and wind. In addition, we review LSE procurement processes to determine how publicly available documents communicate what configurations and technologies are most economically attractive to LSEs and how the processes allow solar developers and equipment manufacturers to communicate to the LSE their technologies' capabilities (e.g., PV tracking, natural gas firing in CSP plant boilers, and integrated storage). This review evaluates the impression that LSE planning and procurement

[2] Madaeni et al. (2012b) only present changes in the value of CSP with thermal storage and the solar multiplier in $/kW terms, not $/MWh terms. Based on simple calculations using their figures it appears that adding 4 hours of thermal storage and increasing the solar multiple from 1.5 to 2.0 increases the value of CSP by about $10/MWh in Nevada and by about $20/MWh in Death Valley (about half of that increase in the value with thermal storage comes from the sale of ancillary services based on the CAISO ancillary service prices between 2001 and 2005).

[3] Austin Energy is beginning to offer a solar tariff to PV customers that compensates PV generation at a rate set to the current year's estimated value of solar to the LSE (Rábago et al. 2012). We do not include this tariff in our analysis because it focuses primarily on designing a fair compensation scheme rather than planning a portfolio of resources. Many concepts used in the design of the Austin Energy tariff are similar to the concepts reviewed in this report.

[4] Of course, solar is but one of many considerations in LSE planning studies; the desire for better representation of solar should be balanced with practical constraints due to limitations in available tools, methods, and time.

[5] "Capacity value" here refers to the economic value related to the savings associated with solar displacing the need to procure other sources of capacity (with units of $/MWh). "Load-carrying capability" represents the amount of additional load that can be reliably met when solar is added to a portfolio (with units of MW). "Capacity credit" refers to the LSE's assumed/estimated load-carrying capability of solar per unit of solar nameplate capacity (represented as a % of nameplate capacity). We maintain these definitions consistently through this document but note that many LSEs and researchers use these terms differently. Most notably, the term we refer to here as "capacity credit" is synonymous with what others sometimes call "capacity value." When we use "capacity value" we mean the economic savings from avoiding other capacity resources, similar to how we use "energy value" to describe the economic savings from reducing production costs.

practices focus too much on levelized cost comparisons that ignore considerations of the economic value of solar (e.g., Joskow 2011[6]). Although this report focuses on solar, a sizeable number of its insights apply to the evaluation of other renewable energy options, such as wind.

This report builds on previous analysis of the treatment of renewable energy (Wiser and Bolinger 2006) and carbon regulatory risk (Barbose et al. 2008) in utility resource plans in the western United States, and a survey of the treatment of solar in utility procurement processes (SEPA 2009, Text Box 1). Research into incorporating renewables, other non-conventional technologies, and uncertainty into utility planning has a long history and remains active. Hirst and Goldman (1991), for example, review best practices for integrated resource planning and distinguish it from traditional utility planning. Doherty et al. (2006) examine the impact of wind in generation portfolios, with particular attention to the benefit of increasing the diversity of generation resources, using mean-value portfolio theory, one of the approaches to understanding optimal generation portfolios reviewed in Bazilian and Roques (2008). Jin et al. (2011) and Vithayasrichareon and MacGill (2012) propose refined methods to solve large-scale generation-expansion problems while accounting for uncertainty. For improving capacity-expansion modeling, Shortt et al. (2012) compare the production costs estimated using a simple dispatch-only model with those using a detailed unit-commitment and economic dispatch model with increasing wind penetration in Texas, Ireland, and Finland. They find that the difference in production costs increases with wind penetration due to conventional generation flexibility issues that are only captured in the unit-commitment model.

Note that this study focuses on the planning and procurement ***methodologies*** used by LSEs. Except for assumptions unique to solar, we do not focus on the particular ***assumptions*** made by LSEs, such as fossil fuel price forecasts, carbon cost estimates, or capital cost estimates for conventional plants. However, such assumptions do impact the value of solar and are likely to have just as much impact on LSE planning decisions as the methodological approach. This review also does not focus on the methods used by LSEs to estimate the costs of building or procuring new solar plants. Other studies illuminate current cost trends, drivers, and uncertainties (e.g., IEA 2011, Barbose et al. 2012, EASAC 2011, Goodrich et al. 2012). Although we do not discuss the solar cost assumptions used by LSEs, all LSEs account for the capital costs of the solar technologies considered in their planning studies and procurement processes.

Section 2 of this report describes the LSE planning and procurement documents we reviewed. Section 3 summarizes the steps LSEs use in planning studies and procurement processes. Section 4 analyzes solar's role in planning and procurement, including discussions of solar capacity values and credits, energy value, integration costs, and other factors as well as the design of candidate portfolios for planning studies and the economic evaluation of bids in procurement processes. Section 5 offers conclusions and recommendations. Following the main text, we provide additional details on the planning and procurement documents we reviewed, LSE

[6] Joskow (2011) states, for example, "The most widely used metric for comparing the 'competitiveness' of different generating technologies is the estimated 'levelized cost' per megawatt-hour (MWh) supplied.…competitive procurement programs run by utilities to meet renewable electricity purchase mandates often use auction mechanisms that effectively choose the supply offers with the lowest levelized cost per MWh regardless of when it is supplied."

planning and procurement practices, and a derivation of net cost based on the objective of minimizing the expected present value of the revenue requirement for a portfolio of resources.

Text Box 1. SEPA survey of LSE perceptions of the value of solar in procurement

Instead of reviewing publicly available planning and procurement documents, as we do in this report, the Solar Electric Power Association (SEPA 2009) directly surveyed LSEs. In response to survey questions about their assessment of solar attributes in procurement, LSEs attached the following qualitative values to solar:

Highest value:

- No emissions of carbon or pollutants
- Carbon offset value

Moderate value:

- Correlation between solar generation and peak hours of utility
- Dispatchability (CSP with storage)
- Elimination of fuel price uncertainty
- Fuel diversification

Lowest value:

- Potential for location close to load
- Minimal water use
- Delay of transmission or distribution investment
- Power factor correction and local voltage support

2. LSE planning and procurement documents reviewed in this report

In order to understand the current practices used by LSEs to estimate the economic value of solar, we reviewed a sample of 16 integrated resource plans (IRPs) or similar planning documents and nine documents outlining evaluation procedures for procurement (Table 1). These documents were created between 2008 and 2012 and are primarily from LSEs in the western United States that are considering solar power, among other options. Details of the planning and procurement approaches used by each LSE is further documented in Appendix A.

Table 1. Planning studies and procurement practices reviewed in this analysis

Load serving entity or study author	Planning study (year)	Procurement practices (year)
Arizona Public Service	2012	2011
California IOU Process	2010	2011
Duke Energy Carolinas	2011	-
El Paso Electric	2012	2011
Idaho Power	2011	-
Imperial Irrigation District	2010	-
Los Angeles Department of Water and Power	2011	2012
Northwest Power and Conservation Council	2010	-
NV Energy[7]	2012	2010
PacifiCorp	2011	2010
Portland General Electric	2009	2012
Public Service of Colorado	2011	2011
Public Service of New Mexico	2011	2011
Salt River Project	2010	-
Tri-State Generation and Transmission	2010	-
Tucson Electric Power	2012	-

3. Summary of steps used by LSEs in planning studies and procurement processes

The general planning process adopted by many LSEs followed a similar pattern: the LSE conducted the planning study, identified a preferred plan from the study, and then issued a request for proposals (RFP) for project developers to provide power from resources identified in the preferred portfolio.[8] In this section we briefly describe the structure of the approach used by LSEs in these planning studies and procurement practices. Figure 1 simplifies the varied plans reviewed for this report. Not all LSEs exactly followed these steps: depending on the plan, some steps were not included, multiple steps were bundled into one step, or the order of steps did not follow this same pattern. For details, see the list of planning and procurement documents reviewed at the end of this report.

The most important steps for considering solar are the creation of feasible candidate portfolios (Step 2) and the evaluation of candidate portfolio costs and impacts (Step 3), so our later review emphasizes these steps.[9] In the meantime, the following subsections describe each step and then provide a simple illustration of how the costs and benefits of solar can be evaluated in planning studies.

[7] We only reviewed the southern Nevada plan for NV Energy in this report.
[8] Developers may construct a plant that will then be owned by the LSE, construct a plant whose output will be sold under long-term contract to the LSE, or contract to sell power to the LSE from an existing facility on a short-term (a few years or less) or long-term (more than 10 years) basis. In some cases the LSE may build the plant itself if the options from project developers are not more attractive.
[9] Candidate portfolios are groups of demand-side and supply-side resource options, including solar, that are evaluated in the planning studies and used to justify the LSEs preferred portfolio or strategy going forward.

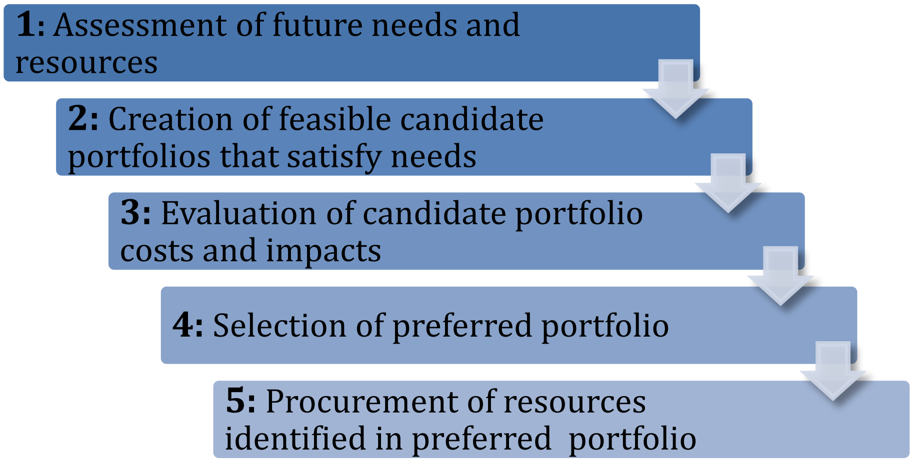


Figure 1. General steps followed by LSEs in planning and procurement

3.1 Step 1: Assessment of future needs and resources

In the initial stage of their planning studies, the LSEs evaluated expectations and uncertainties for elements that may impact their operations and options in the future. They considered demand forecasts, cost and availability of demand-side management measures, existing generation and contracts, expectations for generator retirement, regulatory and policy constraints, and new generation options, characteristics, and costs. Often a key result of this step was the identification of the gap between existing and planned generating resources in each year and the forecast of peak demand plus a planning reserve margin (Figure 2). This gap describes a constraint that the combination of resources in each candidate portfolio must be able to meet, but it does not describe a decision in terms of what resources can be part of candidate portfolios that satisfy this constraint. In other words, not all resources must contribute equally to meeting this constraint as long as the combination of resources meets the constraint.

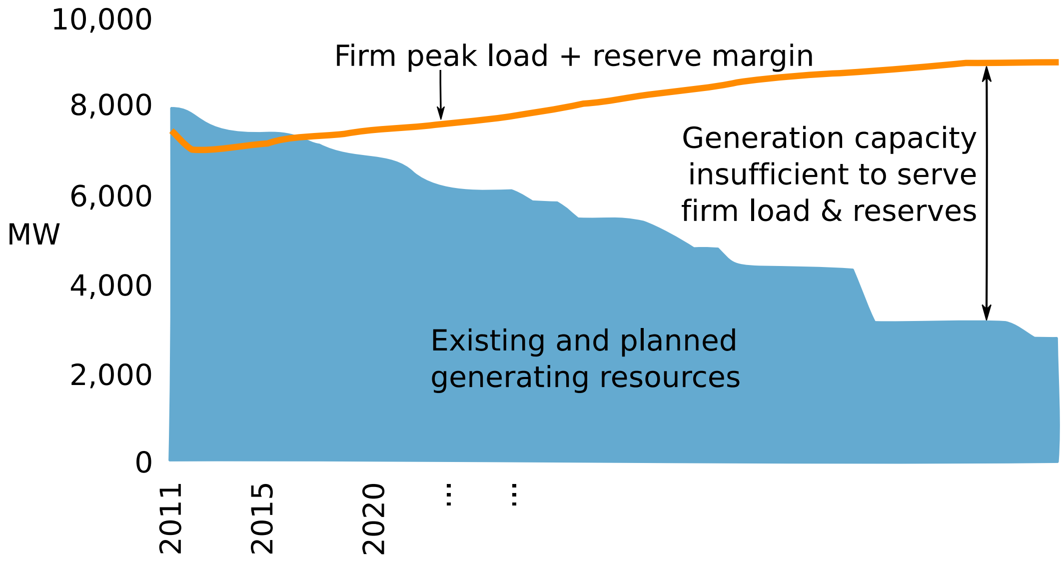


Figure 2. Example of expected future peak loads and existing resources (adapted from PSCo)

Expected future demand levels impacted the degree to which an LSE may need additional capacity and what time of day and year demand was expected to be highest. Understanding future demand included forecasting load growth, understanding trends in energy efficiency, identifying options available for demand-side management (both in terms of LSE-led energy efficiency programs and demand-response programs), and adhering to regulatory requirements for implementing demand-side measures. The level of detail and sophistication used to assess demand-side resources in the planning studies varied across the LSEs.

The supply side included both existing and new resources. These supply-side resource options determined in part the costs that could be avoided by including solar in a portfolio instead of other supply options. Costs for existing generation included assessments of future operations and maintenance (O&M) costs, the need for major equipment upgrades or replacements, and future fuel and pollution (including potential carbon dioxide) costs. The LSEs also considered the impact of increasingly stringent Environmental Protection Agency regulations on the costs and operation of existing assets.

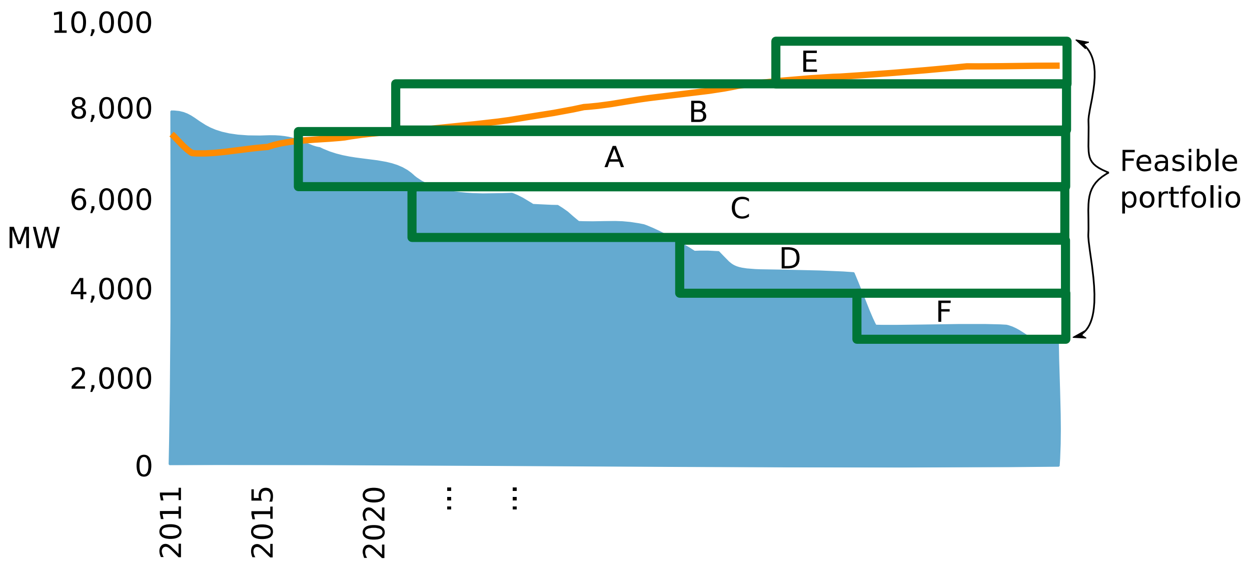
The assessment of new generation resources considered future fuel costs and environmental regulations. Fuel price forecasts were handled in different ways across studies; frequently NYMEX futures and proprietary fundamental energy market models managed by third parties were used in the planning studies. Additional detail on various fuel price forecasts and the treatment of uncertainty in planning models for LSEs in the western U.S. is provided by Larsen and Wilkerson (2012). In addition, LSEs estimated the capital cost of conventional and renewable generating options. Some also evaluated the availability and cost of procuring energy from wholesale power markets in future years.

For renewables, LSEs considered RPS requirements and the dependence of RPS requirements on future demand. In some cases RPSs specify a carve-out for solar generation or distributed generation (DG) that the LSEs also considered in designing feasible candidate portfolios. In Arizona, for example, Arizona Public Service (APS) and Tucson Electric Power (TEP) expected a significant portion of the DG requirement in the state's RPS to be met with distributed PV. Many included an assessment of future availability and timing of tax-based incentives for renewables and the resulting cost implications. Finally, many LSEs considered the ability to purchase unbundled renewable energy certificates (RECs) in lieu of RECs that are bundled with power that is delivered to the LSE. When there was no RPS requirement, some LSEs considered potential future prices for RECs from their renewable generation that they could sell to other markets.

A number of LSEs included an evaluation of existing and/or new transmission in their assessment of needs. In some cases, the need for transmission expansion was linked to particular generation options or import limitations that required reliance on broader wholesale markets to meet future needs. In other cases, transmission was driven by factors not linked to specific generation choices. Overall, LSEs did not appear to emphasize how transmission costs would vary across resource choices as much as other factors like resource capital and fuel costs. As noted by Schwartz (2012), availability of existing transmission is often the primary consideration for determining potential resources, rather than the cost of building new transmission, for LSEs in the western United States.

3.2 Step 2: Creation of candidate portfolios that satisfy these needs and constraints

The LSEs often needed to reduce a wide range of future options into a set of ***multiple*** feasible resource portfolios that could then be analyzed with available tools and methods. Generally, "feasible" meant that the candidate portfolios met all state and federal regulatory requirements. In almost all cases this also meant that the generating resources in each candidate portfolio could meet peak load (plus planning reserve margins) and annual energy demand (Figure 3).[10,11] A key element in this step was estimating the load-carrying capability of solar, i.e., the amount of additional load that can be met without decreasing the reliability of the system. LSEs used different approaches to estimating solar load-carrying capability. We refer to the LSE's estimate of load-carrying capability for each solar technology per unit of nameplate capacity as the "capacity credit" for that technology.



Note: The rectangles labeled A through F represent different resource options that illustrate one feasible portfolio (of many) to meet the peak load and planning reserve needs.

Figure 3. Example of the creation of a feasible candidate portfolio (adapted from PSCo)

We found that three basic methods were used in current LSE planning studies to create feasible candidate portfolios (although some LSEs did not describe the approach they used):

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[10] Generating resources did not necessarily need to be under long-term contract to the LSE to count toward satisfying its peak demand needs, but studies usually identified the total capacity that needed to be at least under short-term contract.

[11] One exception was the Northwest Power and Conservation Council (NPCC), which is primarily concerned with adequate energy rather than adequate capacity. The Pacific Northwest has significant amounts of energy-limited hydropower that can provide large amounts of power but not for an extended period. The "feasible" portfolios, therefore, are not required to satisfy particular capacity needs; instead, portfolios with too little generation result in large exposure to market purchases that may be uneconomic owing to the assumed high volatility of market prices.

- Manual/engineering judgment
- Commercial capacity-expansion models
- Ranking of wide range of resources

With the manual approach, no clear formula or objective was used to create feasible portfolios. Instead, logical arguments based on the trends observed in the assessment of needs and resources (engineering judgment) or stakeholder inputs were used to create feasible portfolios. Often a number of “bookend” portfolios were created to demonstrate the extent to which different portfolios lead to different revenue requirements or different levels of exposure to risk.

Commercial capacity-expansion models used mathematical search algorithms (typically based on linear, mixed-integer, or dynamic programming) to evaluate hundreds or thousands of potential resource combinations under a specific set of assumptions. The models selected the portfolio that minimized the present value of the revenue requirement (PVRR, including capital and dispatch costs). In some cases LSEs created multiple candidate portfolios by varying the assumptions input to the capacity-expansion model and selecting the optimal portfolio for each particular set of assumptions.

A few studies applied a ranking, often based on economic criteria, to the variety of resource options available to the LSE. In one case, non-economic factors (shortest time to bring renewables online and lowest environmental impact) were used to determine the composition of renewable resources included in candidate portfolios. Only the highest-ranked resources were then chosen for further evaluation in candidate portfolios.

3.3 Step 3: Evaluation of candidate portfolio cost and impacts

The costs and impacts of candidate portfolios were then quantitatively evaluated. Fixed capital, variable fuel, and O&M costs were estimated to calculate the PVRR of each portfolio. The PVRR is based primarily on the capital cost of each portfolio and the variable cost of dispatching each portfolio to maintain a balance between supply and demand over the planning period. The exposure of the portfolio to changes in costs based on uncertainties about the future was often evaluated to identify the relative risk of each option (Figure 4).

In this step, including solar in a portfolio resulted in changes in the dispatch of other generation resources, along with reductions in overall portfolio exposure to changes in future fuel and carbon prices. The dispatch of the candidate portfolio was typically simulated using a production cost model. The capital and fixed costs were commonly evaluated using a financial analysis model that transformed streams of future expenditures into a present value.

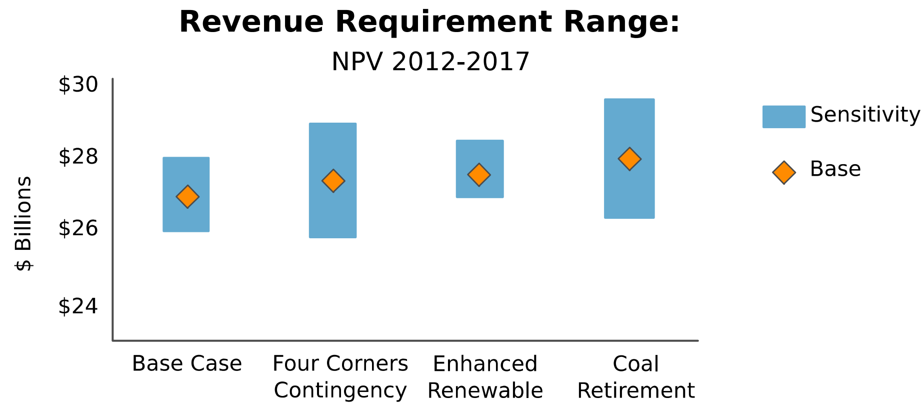

Figure 4. Example evaluation of the sensitivity of revenue requirement to different assumptions about the future for various portfolios (adapted from APS)

Portfolios were evaluated across LSE planning studies in three primary ways:

- **Deterministic evaluation:** A small number of LSEs simply estimated the PVRR for each candidate portfolio using one set of assumptions regarding future costs and needs. This approach is used in the illustration summarized later (Table 2).

- **Deterministic evaluation with specific sensitivity cases:** Many LSEs first estimated the PVRR of each portfolio based on a reference set of assumptions about future costs and needs and then examined the sensitivity of the PVRR to changes in those assumptions using specific sensitivity cases. The sensitivity cases not only showed how the PVRR of each portfolio was exposed to changes in assumptions, but also how the relative ranking of portfolios on a PVRR basis would change under different assumptions, including natural gas and carbon dioxide prices, load growth or energy efficiency program effectiveness, and retirement decisions for existing plants (often older coal plants). The uncertainties included in the sensitivity cases were often justified by the analysts' assessments of future resource options and costs in Step 1. Typically the sensitivity cases changed one variable at a time, with a high and low case for each variable. In other cases multiple variables were changed simultaneously (e.g., high gas price and high carbon dioxide price vs. low gas price and low carbon dioxide price) to examine "best case" or "worst case" scenarios. The high and low variable estimates were often based on values that showed the upper or lower range of what was considered reasonably possible.[12]

[12] A number of LSEs indicated their preference for the use of sensitivity cases using bookend scenarios over more complex Monte-Carlo simulations. Their reason was the transparency and clarity that single-variable sensitivity cases provided: the analysts could understand the degree to which the PVRR would change under the given sensitivity conditions. For example PGE stated:

> While we believe that both stochastic and deterministic scenario analyses provide important insights for assessing the performance and reliability of a portfolio over time, we have found that the most substantial risks in connection with making future resource choices are those associated with large fundamental or structural shifts – the types of risk best described through scenario analysis. As a result, we believe that scenario analysis

- **Risk analysis using Monte-Carlo simulation:** A number of studies used Monte-Carlo simulation methods that allow many variables to change simultaneously within a distribution of potential future values. Monte-Carlo analysis required analysts to specify distributions of future values for each variable as well as the correlation between different variables. The PVRR of a portfolio was then estimated for hundreds of random draws from these distributions. As a result, the PVRR of each portfolio would also be a random variable with its own distribution of potential outcomes. Often the LSEs summarized the distribution of the PVRR for each portfolio with the average over all draws (the expected PVRR) and some metric that described the upper tails of the distribution (the risk of the portfolio).[13] Variables used in the Monte-Carlo simulation often included natural gas prices, load variations, and carbon dioxide prices. Again, the choice of these variables was often justified by the analysts' assessments of future resource options and costs in Step 1. In some cases, hydropower availability, generating plant forced outages, and wholesale electricity prices (among other variables) were included in the Monte-Carlo analysis. Although Monte-Carlo methods can account for correlation between uncertain variables, LSEs often assumed that all variables were uncorrelated.

3.4 Step 4: Selection of preferred portfolio

After the analysis in step 3, four main methods were used to identify the preferred portfolio among the multiple candidate portfolios:

- **Lowest PVRR:** In a number of cases, the LSE's preferred portfolio was the portfolio with the lowest PVRR. Some LSEs did not assess the risk or degree to which the PVRR of different portfolio options would change if assumptions about the future changed.
- **Qualitative tradeoff between low PVRR and low risk:** Where scenario analysis was used to evaluate how the PVRR might change with different assumptions about the future, LSEs would sometimes use those results to adjust their preferred portfolio in an ad-hoc fashion to be a portfolio that was relatively low cost but also less risky. In some cases, for instance, the portfolio with the lowest expected cost might rely on purchases from the wholesale market instead of the LSE building or contracting for a new asset. The PVRR of this portfolio could increase greatly if wholesale prices varied within the plausible range posited by the LSE. In that case the LSE would choose a portfolio that had the next lowest cost but less exposure to the risk of high wholesale power prices.

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should be given the primary emphasis in our overall portfolio risk evaluation. However, we do also continue to consider the instructive value from the stochastic analysis.

Ultimately no degree of modeling and analysis can account for all possible future uncertainties. Modeling by its nature only provides an estimate or range of estimates of future results. Nevertheless, we believe that a well-reasoned and complementary application of both scenario and stochastic analysis can provide useful insights about how a candidate portfolio is likely to perform in the future.

[13] Common risk measures included the value at risk (VaR), which is the PVRR at some particular high percentile of Monte-Carlo draws (e.g., the PVRR for the 90^{th} percentile), and the conditional value at risk (CVaR), which is the average PVRR for the most costly fraction of all draws (e.g., the average of the PVRR for the most costly 10% of draws).

- **Detailed weighting between expected cost and value at risk:** Some LSEs weighted the portfolio's expected PVRR against a quantitative measure of the portfolio's risk, such as the value at risk (e.g., the PVRR of the portfolio at the 90th percentile in the Monte-Carlo analysis). To estimate the expected PVRR and the PVRR at risk, the LSE had to perform a Monte-Carlo analysis with several hundreds of different potential futures.
- **Detailed weighting among many factors:** In some cases, additional factors were used to evaluate the attractiveness of each portfolio, e.g., by scoring based on cost, risk, reliability, resource diversity, or other factors.[14] This approach expands on the cost vs. risk tradeoff by adding other factors that may be important but are not clearly covered in the quantitative portfolio evaluation.

3.5 Step 5: Resource procurement

Often LSEs created IRPs using publicly available information and generic representations of generating options. When procuring resources, the LSEs solicited bids to meet the needs identified in the preferred strategy. These bids could differ from the assumptions in the planning study in terms of cost, resource type, resource location, and generating profile. LSEs that also owned generation assets (like many western U.S. utilities) could also propose to build new generation that would satisfy the needs identified in the planning study (i.e., the "build" option rather than the "buy" option). Some LSEs used an independent evaluator to compare bids in order to mitigate potential conflict of interest. In most cases, the LSE's RFP described how the economic attractiveness of each bid would be estimated along with the information required by the LSE or the independent evaluator to evaluate each bid. LSEs often included non-economic factors such as bidder experience as part of the bid evaluation.

3.6 Bringing it all together: A simple illustration of a resource planning study with PV

To illustrate the basic mechanics of many of the planning studies that included solar, we present a simple conceptual example of how different resource portfolio options can be created and compared. We then use this simple example to illustrate the economic value of solar and the key drivers of this value.

3.6.1 Illustrative feasible candidate portfolios

In this simple example, we consider a hypothetical LSE with an expected peak load and planning reserve margin of 10,000 MW and electricity demand of 28.3 TWh in a future year (Figure 5).

[14] PGE, for example, developed a very detailed method for identifying its preferred portfolio from the many that were evaluated. Both scenario analysis based on several key uncertainties (future fuel prices, carbon prices and carbon price timing, availability of renewable tax incentives, and wholesale market prices) and Monte-Carlo analysis were used to evaluate 15 portfolios created by PGE. PGE then applied a scoring to each portfolio based on its ranking in terms of cost, risk, reliability, and resource diversity. The preferred portfolio was the one with the highest score by weighting each of the different categories as follows: 20% based on reliability and diversity metrics, 30% based on portfolio risk metrics, and 50% based on expected cost.

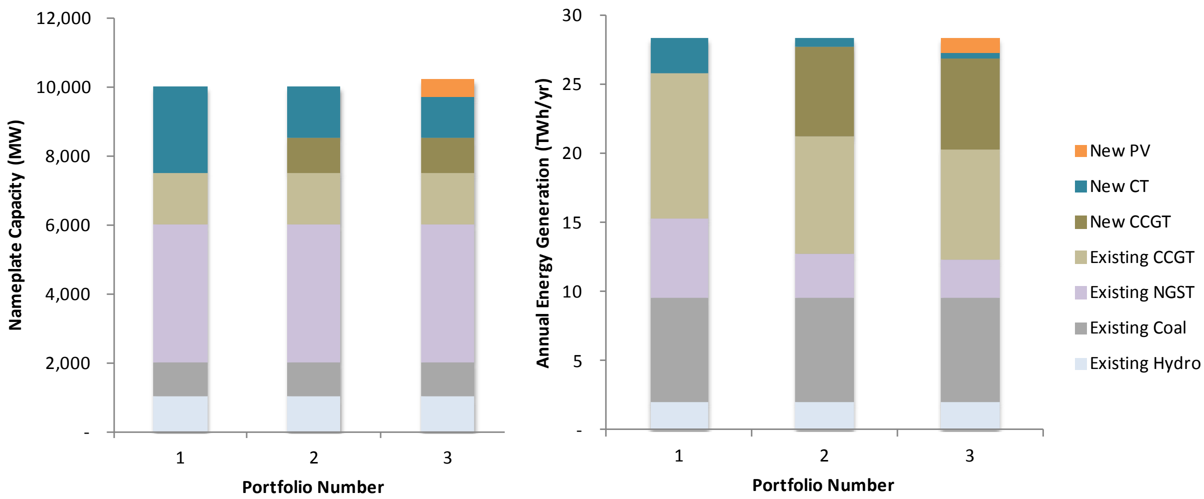

Figure 5. Portfolio composition and hypothetical dispatch

To satisfy this future demand, we create the three feasible candidate portfolios shown in Figure 5. Each portfolio maintains all of the existing generation capacity; the portfolios differ only by the generation capacity added to satisfy future needs. Portfolio 1 adds only new combustion turbine (CT) capacity, Portfolio 2 adds CT and combined cycle gas turbine (CCGT) capacity, and Portfolio 3 adds CT, CCGT, and PV (500 MW) capacity. In each case the total capacity of all resources is sufficient to maintain the same level of reliability across all portfolios.

Assuming in this example that PV has a *capacity credit* of 50% of its nameplate capacity for this particular LSE and portfolio, then only 250 MW of the 500 MW of PV count toward the peak load and planning reserve target (the actual estimates of the capacity credit used by LSEs and the methods used to estimate the capacity credit are described in the next section). The addition of 500 MW of PV to Portfolio 3 therefore allows 250 MW of capacity (CT in this case) to be removed relative to a similar portfolio without PV (e.g., Portfolio 2). Since adding 500 MW of PV only removes 250 MW of CT, the overall nameplate capacity of Portfolio 3 is 250 MW greater than the overall nameplate capacity of Portfolio 1 or 2. The annualized fixed cost of each portfolio (excluding the capital cost of PV) is shown in Row “d” in Table 2.

Table 2. Evaluation and comparison of three hypothetical portfolios

		Units	Portfolio 1: Only Capacity	Portfolio 2: Capacity and Energy	Portfolio 3: Capacity, Energy, and PV	Notes and assumptions:
	Peak Load + Reserve Margin	(MW)	10,000	10,000	10,000	
	Existing NGST	(MW)	4,000	4,000	4,000	$30/kW-yr fixed cost
	Existing Coal	(MW)	1,000	1,000	1,000	$50/kW-yr fixed cost
	Existing CCGT	(MW)	1,500	1,500	1,500	$30/kW-yr fixed cost
	Existing Hydro	(MW)	1,000	1,000	1,000	$50/kW-yr fixed cost
	New CT	(MW)	2,500	1,500	1,250	$150/kW-yr fixed cost
	New CCGT	(MW)	-	1,000	1,000	$200/kW-yr fixed cost
	New PV	(MW)	-	-	500	$250/kW-yr fixed cost after ITC, 50% capacity credit
	Total Nameplate Capacity	(MW)	10,000	10,000	10,250	
	Annual Demand	(TWh/yr)	28.3	28.3	28.3	
	Existing NGST	(TWh/yr)	5.8	3.2	2.8	$60/MWh variable cost
	Existing Coal	(TWh/yr)	7.5	7.5	7.5	$25/MWh variable cost
	Existing CCGT	(TWh/yr)	10.5	8.5	8.0	$50/MWh variable cost
	Existing Hydro	(TWh/yr)	2.0	2.0	2.0	$5/MWh variable cost
	New CT	(TWh/yr)	2.50	0.60	0.42	$80/MWh variable cost
	New CCGT	(TWh/yr)	-	6.5	6.5	$40/MWh variable cost
a	New PV	(TWh/yr)	-	-	1.10	25% capacity factor
	Total Annual Generation	(TWh/yr)	28.3	28.3	28.3	
b	Existing Fixed Cost	($M/yr)	$ 265	$ 265	$ 265	
c	New Fixed Cost (Excluding PV)	($M/yr)	$ 375	$ 425	$ 388	
d = b + c	Total Fixed Cost (Excluding PV)	($M/yr)	$ 640	$ 690	$ 653	
	Variable Cost (with no PV integration cost)	($M/yr)	$ 1,261	$ 1,113	$ 1,048	
e	Variable Cost (Including PV integration cost)	($M/yr)	$ 1,261	$ 1,113	$ 1,053	Assumed $5/MWh integration cost for PV
f = d + e	Fixed + Variable Cost (w/o PV capital cost)	($M/yr)	$ 1,901	$ 1,803	$ 1,706	
g	PV Fixed Cost	($M/yr)			$ 125	
h = f + g	Total Cost (incl. PV Cost)	($M/yr)	$ 1,901	**$ 1,803**	$ 1,831	
i = f2 - f3	Avoided Cost of PV	($M/yr)			$ 97	
j = g - i = h3 - h2	Net Cost of PV	($M/yr)			$ 28	
k = g / a	PV Cost	($/MWh)			$ 114	
l = i / a	**Avoided Cost of PV**	**($/MWh)**			**$ 88**	
m = j / a = k - l	Net Cost of PV	($/MWh)			$ 26	

3.6.2 Evaluation of candidate resource portfolios

The dispatch of the existing and new generation, typically estimated using a production cost model, is assumed in this example to differ based on the resources available in each of the portfolios, as shown in Figure 5. Portfolio 1 requires significantly more of its energy to be generated by CTs and existing natural gas steam turbines (NGSTs) compared to Portfolio 2 and 3, which both have more CCGTs and PV. In particular, the addition of PV in Portfolio 3 displaces energy from new CTs, existing NGSTs, and existing CCGTs. We assume hydropower is dispatched differently in each portfolio, although the annual energy production remains the same. Owing to the relatively low variable cost of coal, the addition of PV to the portfolio does not affect the dispatch of the existing coal. In addition, PV is assumed to contribute an additional $5/MWh *integration cost* due to factors not represented in the other variable cost estimates such as the cost of day-ahead forecast errors and/or additional ancillary services (the actual integration costs used by LSEs and the methods used to estimate them are described in the next section). Including this integration cost, the annualized variable cost of each portfolio based on the assumed dispatch is shown in Row "e" in Table 2. The total annualized cost of each portfolio (both fixed and variable and including the capital cost of PV) is shown in Row "h."

3.6.3 Comparison of portfolios and selection of preferred portfolio

In this simple example, Portfolio 2 is the least-cost portfolio, as shown by Row "h" in Table 2, with an annualized cost of $1,803 million/yr. This portfolio can serve as a reference point to understand two key concepts regarding the relative economic value of PV: the *avoided cost* of PV and the *net cost* of PV.

The avoided cost of PV shows how much would be saved if the energy from the 500-MW PV plant could be added to Portfolio 3 without any capital cost associated with the PV installations. The cost of Portfolio 3 with no PV cost would be $1,706 million/yr (Row "f"). The avoided cost of the energy from PV relative to the preferred portfolio, Portfolio 2, would be $97 million/yr (Row "i") or $88/MWh (Row "l").

The capital cost of PV is not free, however, and in this case has an annualized cost of $125 million/yr for 500 MW after reducing the cost by the current Investment Tax Credit (or a levelized cost of $114/MWh[15]). Factoring this cost into Portfolio 3 pushes its cost above the cost of Portfolio 2. The net cost of PV is the capital cost of PV ($125 million/yr) less the avoided cost of PV ($97 million/yr). In this case the net cost of PV is $28 million/yr (Row "j") or $26/MWh (Row "m"). Based on how this cost was derived, the net cost of PV ($28 million/yr) can be added to the total cost of the least-cost portfolio (Portfolio 2: $1,803 million/yr) to come up with the total cost of Portfolio 3 including the cost of PV ($1,831 million/yr). In other words, the net cost of PV in this case represents the total cost above the cost of the least-cost portfolio due to the addition of PV to Portfolio 3. Further, if the avoided cost of PV were to increase by $26/MWh (due to increased prices for fossil fuel or carbon dioxide for instance) or the capital cost of PV were to decrease by $26/MWh, then the net cost of PV would be $0/MWh. In this case the total cost of Portfolio 3 would be equivalent to the total cost of the current least-cost portfolio.

3.6.4 Overall economic assessment of PV

This simple example highlights a few important points about this approach:

- **The composition of each portfolio impacts the apparent avoided costs of PV.** We could have just as easily added PV only to the much more expensive Portfolio 1. The apparent avoided costs of PV would have dropped tremendously in this case owing to the high operating cost of the CTs in the first place. To gauge the true avoided cost of PV, and hence the relative cost of any portfolio that includes PV, the portfolios must be well

[15] The levelized fixed cost could be replaced with the amount the LSE would pay to independent PV owners if the LSE procured the PV power through long-term PPAs instead of building and owning the PV.

designed to minimize costs. Another way to ensure this would be to create and evaluate many combinations of portfolios so the “right” combination that accurately assesses the value of PV is included in the set of examined portfolios. Commercial capacity-expansion models, used by a number of the LSEs to identify feasible candidate portfolios, generally evaluate hundreds of combinations of different generation resources while searching for portfolios that minimize the PVRR. While that process was not replicated in this simple example, these tools can help identify good combinations of resources for candidate portfolios. For instance, a capacity-expansion model could identify a reference portfolio that is used to evaluate marginal changes in costs and benefits with marginal changes in the composition of that portfolio.

- **It is important to create a new portfolio with PV rather than simply adding PV to the original least-cost portfolio.** In the example, Portfolio 3 has 250 MW less CT capacity than Portfolio 2 owing to the 50% capacity credit of PV. Had we simply added PV to Portfolio 2 without accounting for the capacity credit of PV, the avoided cost would drop from $88/MWh to $54/MWh. The difference in avoided cost with and without consideration of the capacity credit of PV can be considered the *capacity value of PV*, which in this case is responsible for $34/MWh of the total avoided cost of PV. This shows that it is not appropriate simply to add PV to other portfolios already designed to satisfy capacity needs. The addition of new resources to a portfolio should be accompanied by a removal of resources that are no longer needed to maintain the same level of reliability across portfolios.

- **The dispatch of generation in each portfolio also contributes to the avoided costs**. In addition to the capacity credit of PV, the remaining contributor to the avoided cost is the avoided variable costs of the conventional power plants less the integration costs. The *energy value of PV*, or the avoided cost prior to accounting for the integration cost, in this case would be $59/MWh. Factors that impact overall production costs but are not accounted for in the dispatch models used to estimate the energy value (like day-ahead forecast errors or ancillary service [AS] costs) may require adjusting the estimate of the energy value. With an assumed $5/MWh integration cost for PV, for instance, the total avoided variable cost of PV would equal $54/MWh. This energy value will depend on the dispatch of all of the generation including the contribution of PV and thus highlights the importance of considering dispatch.

In summary, this simple example illustrates the creation of feasible portfolios, evaluation of the cost of each portfolio, and identification of the least-cost portfolio. It also introduces the concepts of *avoided cost of PV* (the difference in cost between the least-cost portfolio and the portfolio with PV assuming PV is free), *net cost* (the fixed cost of PV less the avoided cost), *capacity value* (the portion of the avoided cost due to the load-carrying capability of PV as represented by the capacity credit estimated by the LSE), *energy value* (the portion of the avoided cost from reducing the dispatch of conventional plants), and *integration cost* (an adjustment to the energy value due to factors like day-ahead forecast errors or AS requirements that are not captured in the portfolio evaluation). Throughout the remainder of this report we refer to these concepts to compare the methods used in practice by LSEs.

4. Analysis of LSE treatment of solar in planning and procurement

In this section we compare the treatment of solar across the various approaches used by the LSEs as each loosely followed the steps described in the previous section. Where appropriate, we also compare assumptions or approaches used in the LSE studies to the broader literature on solar valuation. We summarize key components included in the LSEs' evaluation such as the types of solar technologies considered; the treatment of the capacity value (with particular on the assumed capacity credit of the various solar technologies), energy value, and integration costs of solar energy; the LSEs' treatment of other factors including the risk reduction value of solar, impacts to the transmission and distribution system, and options that might mitigate solar variability and uncertainty; the methods LSEs use to design candidate portfolios of resources for evaluation within the studies; and the approaches LSEs use to evaluate the economic attractiveness of bids during procurement.

4.1 Solar technologies considered in planning and procurement

The potential solar technologies assessed by LSEs varied across planning studies. A list of solar technologies included in at least one of the studies is presented in Table 3.

Table 3. Solar technologies included in assessment of potential future resources

Solar technology category	Variation	Integrated thermal storage	Natural gas firing in boiler
Photovoltaic	Fixed	N/A	N/A
	Single-axis tracking	N/A	N/A
	With lead acid battery	N/A	N/A
Concentrating solar power	Parabolic trough	None	No
	Parabolic trough	None	Yes
	Parabolic trough	3 hours	No
	Parabolic trough	6-8 hours	No
	Solar power tower	7 hours	No
	Solar chimney (or solar updraft tower)	None	No
Solar thermal gas hybrid plants (or integrated solar combined cycle, ISCC)		N/A	N/A

A large range of solar technologies has been demonstrated commercially (Arvizu et al. 2011). LSEs might want to consider, at least at a screening level, this large range in their planning studies. Flat-panel PV technologies (both fixed and tracking) are suitable for much of the United States, whereas parabolic-trough and power-tower CSP with or without thermal storage or natural gas augmentation are suited for regions with ample direct normal insolation.[16] These

[16] Recent analysis of high renewable scenarios in the United States can help identify regions suitable for CSP. The DOE *SunShot Vision Study* included CSP in California, Arizona, Nevada, Utah, Colorado, New Mexico, and Texas in a 2050 scenario (DOE 2012). The NREL *Renewable Electricity Futures Study* identified a similar geographic distribution of CSP plants in a 2050 scenario where 80% of U.S. electricity is provided by renewable resources (NREL 2012). The same studies included PV in every state in the scenarios.

technologies are all considered mature enough for commercial application (EASAC 2011). In addition, several solar thermal gas hybrid plants, each with more than 20 MW from solar, are now in operation or under construction around the world (Arvizu et al. 2011). Other technologies, such as solar chimneys, are still in the pilot or early demonstration stage; the lack of detailed cost and performance data for these technologies makes them more difficult to assess than PV or CSP.

4.2 Recognition of solar capacity value in planning studies

4.2.1 Creation of feasible candidate portfolios implicitly provides capacity value

The capacity value of solar is based on the reduced need for new conventional capacity to maintain reliability. As shown in Section 3.6, adding solar to a portfolio can displace new CT or CCGT capacity in that portfolio. In almost all LSE planning studies reviewed here, the amount of resources added to each portfolio (including solar) was sufficient to meet the LSE's forecasted peak load and planning reserve margin over the planning horizon. These portfolios accounted for the lower load-carrying capability of wind and some solar technologies (see Section 4.3). Similarly, we rarely found cases in which the portfolio capacity exceeded the peak load and planning reserve margin.[17] As a result, adding solar reduced the need for some other capacity resource to meet the peak load and planning reserve margin (or maintain constant reliability across portfolios). In a few cases, the LSE's modeling approach reduced wholesale power market exposure during peak-load periods by adding solar; the LSE assumed the price of power during peak-load periods would include the long-run cost of building a new CT. The displacement of capital and/or variable cost of those capacity resources therefore affected the estimate of the PVRR of the portfolios with solar. The capacity value of the solar technologies was then embedded within the estimate of the PVRR as a combination of the capacity credit of solar and the avoided cost of the capacity resource displaced by the load-carrying capability of solar.

4.2.2 Magnitude of capacity value is driven partly by capacity cost and timing of capacity need

We found that the magnitude of capacity value was driven in part by the assumed cost of capacity and timing of capacity need. In many cases the capacity resource displaced by the load-carrying capability of solar appeared to be the full fixed cost of a CT (e.g., the capacity value of 100 MW of solar with a load-carrying capability of 50 MW would be based on the full fixed cost of 50 MW of new CTs). In those cases the LSE's assumed cost of CTs impacted the capacity value of solar. In a few cases the timing of capacity need also impacted the capacity value of solar: the capacity value could be lower if excess capacity was available in early years. For example, if an LSE did not need additional capacity to meet its peak-load and planning reserve margin for another 5 years, then adding solar now to meet an RPS requirement did not offset the need for other capacity for the first 5 years. The overall capacity value of that solar plant would therefore be lower than if the LSE currently had a need for new capacity.

[17] One exception was the NPCC model, used in a region with large amounts of energy-limited hydro, where a portfolio with low amounts of new generation capacity was found to expose the loads to high prices in the wholesale market. To avoid exposure to these high prices, the model consistently chose portfolios with generating capacity that exceeded minimum levels needed for reliability purposes (i.e., the capacity constraint was not binding).

4.2.3 Lumpiness of capacity options can affect the capacity value of solar

In at least one case (Tri-State), the alternative conventional generation options were very "lumpy" (the only individual conventional power plant options were 290 MW or larger), resulting in no change in conventional generation expansion when small amounts of solar were added. Tri-State did not appear to adjust for this lumpiness, e.g., they did not allow for off-system sales of excess capacity. This lumpiness of conventional capacity options may therefore result in no apparent capacity value of solar even though solar contributes to resource adequacy requirements. Including smaller investment options such as 50-MW or smaller CTs could minimize this issue. These smaller CTs were often included in other LSE studies. Alternatively, LSEs could avoid this problem by always including the option to sell excess capacity or purchase any deficit in capacity in any year at the price of the fixed cost of a peaker plant. More realistic representation of the lumpiness of capacity could be included by restricting those purchases and sales of capacity to increments similar to the size of a peaker plant (e.g., a 50-MW CT).

4.3 Estimates of solar capacity credit in planning studies and broader literature

The amount of other generation capacity that could be displaced by solar while still meeting the peak load and planning reserve requirement depended on the load-carrying capability of the solar technologies assumed by LSE planners. The capacity value of solar (in economic terms) was therefore greatly impacted by the capacity credit the LSE assigned to solar, which was affected in part by the method the LSE chose for estimating the solar capacity credit. Across all LSEs, the solar capacity credit was always positive (with one exception for small PV in California[18]), even though many solar technologies cannot generate at night, and the daytime output varies with cloud cover.

The methods used in estimating the capacity credit of solar varied widely across LSEs, from detailed loss of load probability (LOLP) studies (e.g., APS, Public Service of Colorado [PSCo]) to estimates of solar generation during peak-load periods (e.g., Public Service of New Mexico [PNM], TEP, the California Investor-Owned Utility [CA IOU] process,[19] NV Energy, Idaho Power, Tri-State) to rules of thumb based on engineering judgment (e.g., Portland General Electric [PGE]). A number of utilities did not specify the method used to estimate the capacity credit of solar, e.g., Los Angeles Department of Water and Power (LADWP), Imperial Irrigation District (IID), and SRP.

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[18] A 0% capacity credit was assigned to small PV in the CA IOU process, which assumed that small PV sited on the distribution system could not be counted toward meeting the peak load and planning reserve margin since the resources can connect to the distribution system through a process that does not include a deliverability study required under the California Resource Adequacy program (CPUC 2011a). It is expected that the CAISO will conduct deliverability studies in the near future, however, and even small PV will become eligible for a positive capacity credit.

[19] The capacity credits reported for the CA IOUs in this section were extracted from the *33% RPS Calculator* used in the 2010 Long-Term Procurement Planning process. Once solar (and wind) facilities are operating, the capacity credit applied to the resource for the purposes of the California Resource Adequacy process will be based on the actual operating history of the plant during peak-load periods (CPUC 2011b).

4.3.1 Factors impacting solar capacity credit at low solar penetration

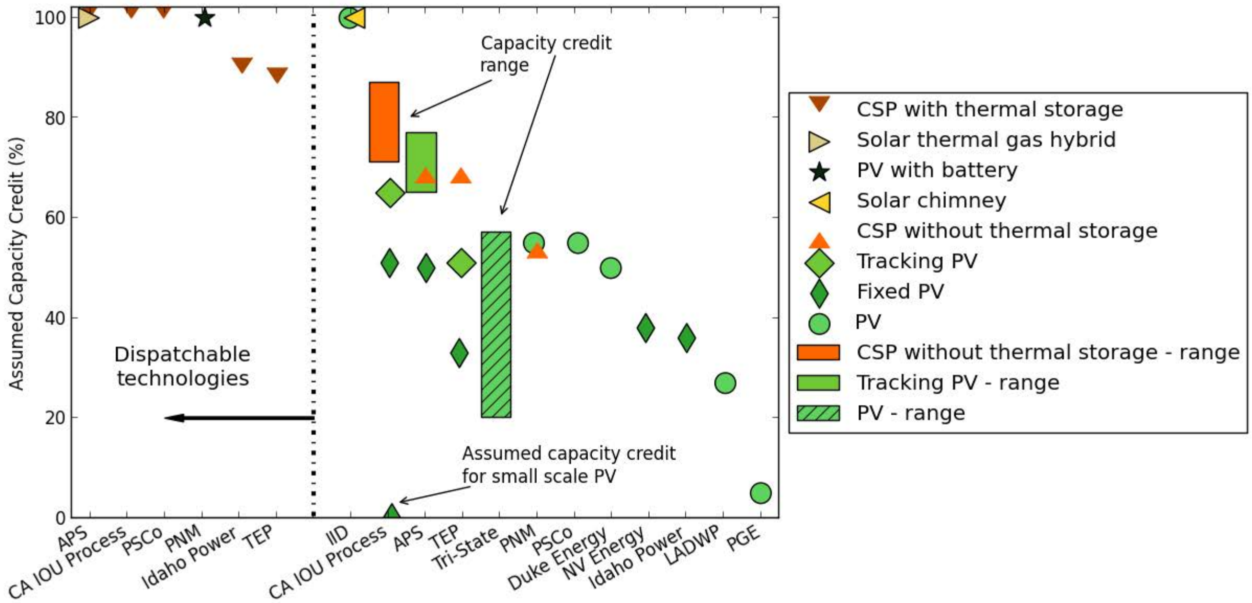
Aside from the approach used to estimate the capacity credit, the correlation of load and solar generation and the solar technology impacted the capacity credit of solar (Table 4, Figure 6). As expected, the capacity credit assigned to solar in regions with good coincidence of insolation and load (e.g., summer afternoon peaking loads) used a higher capacity credit than regions where the coincidence is lower (e.g., winter night peaking loads). Even in regions with summer afternoon peaking load, however, the capacity credit of PV or CSP without thermal storage is not expected to be 100% since peak solar production often occurs earlier in the day (1 pm or earlier) than peak loads (often after 2 pm). The resulting capacity credit applied to PV in the creation of portfolios ranged from 27% to 77% in regions with relatively good coincidence of PV generation and peak loads to 5% for an LSE in the Pacific Northwest where peak loads occur during winter nights (e.g., PGE[20]). In some cases separate capacity credits were estimated for single-axis tracking and fixed PV; the capacity credit for tracking PV appeared to be higher. This higher capacity credit for tracking PV is supported by a detailed comparison of the capacity credit for various PV configurations by Madaeni et al. (2012c). They found that the capacity credit of PV in the Western Electricity Coordinating Council (WECC; assuming zero PV penetration and no transmission constraints across WECC) was 56%–75% for fixed PV, 70%–87% for single-axis tracking PV, and 71%–93% for double-axis tracking PV, depending on location (Figure 7).

Table 4. Capacity credits applied by LSEs in planning studies

Technology	Sub-category	Capacity credit range	LSEs within range
PV	Excluding Pacific Northwest	27% –77%	APS, CA IOU process, Duke Energy, LADWP, NV Energy, PNM, PSCo, TEP
	In Pacific Northwest	5% –36%	Idaho Power, PGE
	With lead-acid battery	100%	PNM
CSP	Without thermal storage or natural gas augmentation	55%–87%	APS, CA IOU process, PNM, TEP
	With thermal storage or natural gas augmentation	87%–100%	APS, CA IOU process, Idaho Power, PSCo, TEP

Note: Imperial Irrigation District (IID) appears to have assumed a 100% capacity credit for PV and a solar chimney. This assumption is excluded from the table because it is not supported by detailed analysis from IID or elsewhere. The California IOU process assumed small-scale PV would have a 0% capacity credit in its net cost ranking; this was also excluded from the table. Tri-State indicated that it estimated the capacity credit of PV to range from 20% to 57%, but it does not specify what value was used in its study. This range is also excluded from the table. All of these excluded values are shown in the corresponding figure.

[20] Although PGE applied the 5% capacity credit to PV in its planning studies, it did not use a quantitative evaluation method to support this value. Instead the value was based on PGE’s judgment that, due to the winter peaking nature of PGE’s demand, the capacity credit for PV was expected to be similar to the capacity credit for wind (which was previously estimated to be 5% in this region).



Note: Imperial Irrigation District (IID) appears to have assumed a 100% capacity credit for PV and a solar chimney.

Figure 6. Capacity credits applied by LSEs in planning studies

The capacity credits used by LSEs for CSP with multiple hours of thermal storage or natural gas augmentation (87%–100% of nameplate capacity) are higher than the capacity credits for CSP without thermal storage or natural gas augmentation[21] (55%–87% of nameplate capacity).

[21] It is not clear if the capacity credit of CSP without thermal storage or natural gas augmentation should be higher than the capacity credit for tracking PV. Comparison of the capacity credit of single-axis tracking PV (70%-87% in Madaeni et al. 2012c) to the capacity credit of CSP with a solar multiplier of 1.5 (53%-75% in Madaeni et al. 2012a) for various solar sites in WECC suggests the opposite: Madaeni et al. show higher capacity credits for single-axis PV than for CSP without thermal storage. Reasons that could justify a higher capacity credit for CSP without thermal storage relative to single-axis PV in the same region include:

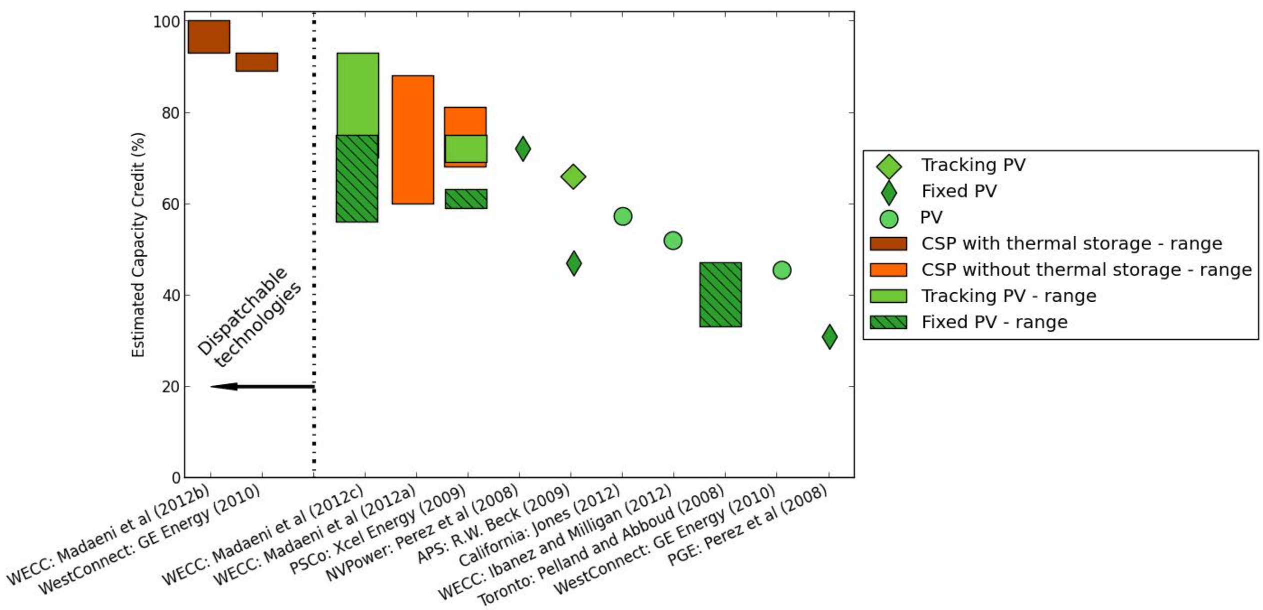
- A CSP plant with a solar multiple (the ratio of the thermal energy from the solar field under standard conditions to the thermal energy required to operate the powerblock at its rated capacity) of greater than 1.0 would have more generation in the evening: Madaeni et al. (2012a) find that for CSP sites in the Southwest increasing the solar multiple from 1.0 to 1.5 can increase the capacity credit from around 60% to around 80%. Increasing the solar multiple of a CSP plant leads to unused solar heat during high insolation periods but increased production in the early evening and morning relative to a CSP plant with a lower solar multiple. The generation profile of single-axis tracking PV is likely to match the generation profile of CSP with a solar multiple closer to 1.0.
- The thermal inertia of a CSP plant would allow it to continue to produce energy for roughly 15 minutes with passing clouds, whereas PV plant output would drop off much more quickly.

On the other hand, single-axis PV could have a higher capacity credit than CSP without thermal storage for the following reasons:

- CSP only uses direct-normal insolation, whereas PV uses direct and diffuse, allowing PV to generate power even from scattered light.

Madaeni et al. (2012b) suggest that multiple hours of thermal storage are needed to obtain a capacity credit over 95%. The studies with CSP with thermal storage that describe the number of hours of storage capacity all have 3 hours of storage or more. The one LSE that considered a lead-acid battery coupled to a PV system, PNM, assumed a capacity credit of 100% for the combined resource. It is not clear how many hours of storage PNM assumed (its current demonstration PV/battery plant has 2 hours of storage capacity), but it is likely that multiple hours of storage would be required to justify such a high capacity credit.

The range of capacity credits used by LSEs in planning studies largely fall within the range reported in the broader literature for low-penetration PV and CSP (Figure 7) and the range reported using various time-based approximation methods within the United States (Rogers and Porter 2012). That said, the wide variation across the LSE studies, even for similar solar technologies in similar locations (e.g., the capacity credit for fixed PV used by APS, TEP, and NV Energy substantially differ even though all the LSEs are in the Southwest) suggests that variations in methods and tools used to estimate the capacity credit are responsible for a portion of the variation.



Note: Original PV capacity credit from GE Energy (2010) was reported based on DC nameplate capacity; here it is converted to AC nameplate capacity.

Figure 7. Estimated capacity credits at low penetration from studies that use LOLP-based methods

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- CSP plants have a minimum generation level at which insufficient thermal input requires the CSP plant to stop producing power. This could lead to a CSP plant producing zero power and a single-axis tracking plant producing some power just before sunset.

Given these conflicting trends in estimates of capacity credits, any distinct difference between the capacity credit of tracking PV and the capacity credit of CSP without thermal storage or natural gas augmentation used by LSEs in planning studies should be confirmed and justified with further detailed studies.

4.3.2 Reduction in capacity credit with increasing solar penetration levels

Only APS appeared to account for the potential change in the capacity credit of solar technologies with increasing penetration (see Appendix A for details on the APS PV capacity credit). LSEs considering large amounts of solar would ideally account for the potential change in the capacity credit of solar with increasing penetration. A number of LSEs are aware of this issue, but in some cases regulatory processes are used to establish the methods or assumptions used for estimating the capacity credit of different technologies. In those cases stakeholders and regulators should consider evaluating changes to existing practices if they do not account for changes in capacity credits with increasing penetration.

In contrast to assuming an unchanging solar capacity credit with penetration, detailed studies of the value of solar indicate that the marginal capacity credit of fixed PV, tracking PV, and CSP without thermal storage (or without natural gas augmentation) can even decline at relatively low penetration levels (Figure 8). While there is a wide range of capacity credits for PV at low penetration levels, the marginal capacity credit declines to 30% or lower at PV penetration levels above 10% on an annual energy basis across all of the examples in the literature. Analysis of many studies in the United States and Europe also shows that the capacity credit of wind generally decreases with increasing wind penetration (Gross et al. 2007, Holttinen et al. 2011).

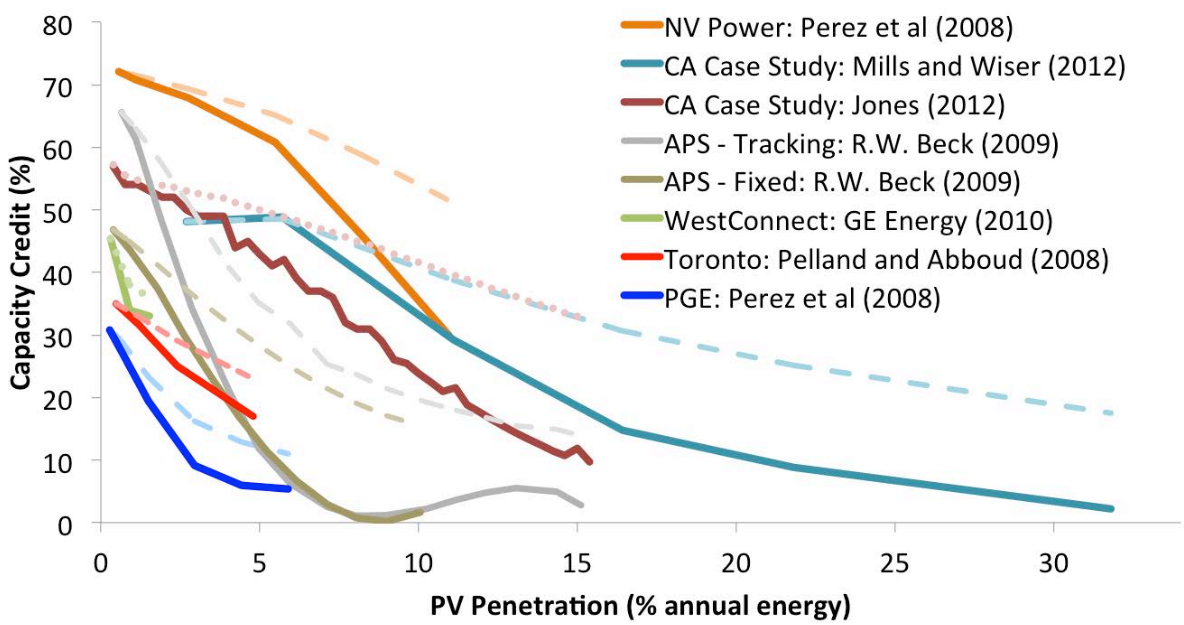
The merits of CSP with thermal storage or natural gas augmentation increase relative to solar technologies without these features partly because they are able to maintain a higher capacity credit with increasing penetration. For example, Mills and Wiser (2012) found the marginal economic value of additional CSP with 6 hours of thermal storage to be about $35/MWh greater than that of single-axis tracking PV when either technology was at 10% penetration on an energy basis. If LSE planning studies do not account for changes in solar capacity credit with increasing penetration, they will not recognize this difference in value between various solar technologies.

The discrepancy between the capacity credit used in planning studies and the potentially lower actual capacity credit at high penetration may not be an important oversight in most current planning studies that only include low solar penetration cases. The studies by the CA IOUs, however, have scenarios that approach high penetration levels at which changes in the capacity credit could be important. APS also has scenarios in which PV penetration exceeds 5% on an energy basis, but the PV capacity credit used by APS accounted for effects of PV penetration across all scenarios. As the penetration of solar grows or as more LSEs consider portfolios with large shares of solar, it is important that changes in the capacity credit with increasing penetration be carefully considered.

It may also be possible to maintain a high capacity credit for PV with increasing penetration in one LSE's region by selling the output of PV during peak periods to neighboring LSEs that have lower PV penetration.[22] This possibility, however, was not considered in the studies. Part of the challenge for realizing this value in planning studies is the need for coordination between various LSEs. Even without increased amounts of solar (and wind), LSEs would benefit from

[22] On the other hand, if both have high PV penetrations, the incremental capacity credit for more PV will be lower for either LSE, lessening any potential benefits from trade.

coordinated evaluation of reliability with other LSEs in the same region. For example, Ibanez and Milligan (2012) find that the load that could be served reliably with aggregation at the sub-region level would be 14% greater than the load that could be served if each LSE considers only its own loads and resources in WECC. The fact that most LSEs consider only their own load and resources, even with the potential value from coordination, suggests that it may be challenging to change this existing practice as more solar is added. To help overcome the coordination challenge, with or without increasing amounts of solar or wind, regional reliability entities such as WECC could act as a repository for LSEs' planning assumptions and conduct regional adequacy evaluation studies.



Notes:
- Mills and Wiser (2012) assume single-axis tracking with latitude tilt.
- GE Energy (2010) and Jones (2012) use PV profiles from a mixture of fixed and tracking PV.
- The scenarios in GE Energy (2010) with PV also have increasing penetrations of CSP with thermal storage and wind.
- In Perez et al. (2008), fixed PV with 30-degree tilt is assumed. Capacity credit is based on their estimate of the effective load-carrying capability (ELCC) of PV. Capacity penetration is converted to energy penetration assuming: NV Power load factor is 42% (based on NV Energy 2012 IRP), NV Power PV capacity factor is 23% (estimated from NREL Solar Advisor Model), PGE load factor is 58% (based on PGE 2009 IRP), and PGE PV capacity factor is 17% (based on PGE 2009 IRP).
- In Pelland and Abboud (2008), capacity penetration is converted to energy penetration assuming that Toronto's load factor is 55%. Fixed PV with 30 degree-tilt is assumed. We show only the results from a south-facing orientation.
- Capacity penetration used in R.W. Beck (2009) is converted to energy penetration assuming: APS load factor is 48% (based on APS 2012 IRP), APS tracking capacity factor is 30%, and APS fixed capacity factor is 23% (based on NREL Solar Advisor Model).

Figure 8. PV capacity credit estimates with increasing penetration levels (dashed line is average capacity credit, solid line is incremental capacity credit)

4.3.3 Planning studies should consider improving estimates of solar capacity credit

Although the range of capacity credits applied to PV technologies and CSP plants with thermal storage or natural gas augmentation is broadly consistent with the range identified in detailed studies at low solar penetration levels, relatively few LSEs used detailed studies to estimate the capacity credit. It appears that only PSCo and APS used LOLP-based reliability analysis of PV among the LSEs considered here. Most other capacity credit estimates were based on rules of thumb, evaluation of solar generation during peak-load periods, or assumptions. The numeric values appear plausible, but, owing to the importance of reliability in planning studies and the importance of the capacity credit for solar's economic value, detailed LSE-specific reliability assessments of capacity credit would be appropriate. In the Pacific Northwest, an area dominated by energy-constrained hydropower resources, these assessments should seek to account for energy limits in the reliability assessments. The importance of estimating solar load-carrying capability will grow as solar's costs decline and it becomes more competitive with other resource options.

4.4 Evaluation of the energy value of solar using production cost models

4.4.1 Production cost models account for solar's ability to offset high cost fuels

Across all planning studies the variable costs associated with dispatching power plants to meet varying demand in future years was simulated using some form of production cost model. For candidate portfolios with solar, adding solar reduced fuel consumption and production costs associated with the dispatch of other power plants. The reduced production costs therefore reduced the variable cost component of the PVRR. These avoided production costs associated with the inclusion of solar in candidate portfolios are referred to as the energy value of solar.

Although the temporal resolution of the production cost models used in the planning studies varied (Table 5), most of the models should have high enough resolution to reflect correlations between solar generation and times when the fuel costs of conventional power plants are high. The planning studies should therefore reflect the relatively high energy value for solar found in the literature. Some planning studies used models with hourly time resolution over a full year. Other studies reduced the amount of computational processing by only selecting an hourly time series of data from one week each month. This approach maintained the hour-to-hour structure of the data within each month, while reducing the number of hours to process by about 75%. However, this approach introduces the possibility that the weeks chosen for analysis are missing periods with extreme events (e.g., potential solar curtailment on spring weekends with high solar and low load). APS further reduced the sampling to one day per month using hourly data. The lowest temporal resolution observed in evaluating portfolios was the use of average on-peak and off-peak values for each quarter of the year. This last approach was used in the Northwest Power and Conservation Council (NPCC) analysis, in which thousands of portfolios were evaluated over 750 different futures, necessitating a reduction in processing complexity. The system evaluated by the NPCC is hydro dominated, and energy deficits are a larger concern than transient events owing to the large nameplate capacity of the system and relatively low amount of energy storage. NPCC's focus on balancing energy over longer periods rather than balancing hour-to-hour supply and demand potentially justifies the use of lower temporal resolution. Such low temporal resolution, however, may not be as appropriate for regions dominated by thermal generation that are constrained primarily by capacity rather than by energy.

Table 5. Temporal resolution of production cost models used in LSE planning studies

Temporal resolution of production cost model	Planning Studies	Production cost model (Company)
Hourly for a full year	CA IOU process	PLEXOS (Energy Exemplar)
	Idaho Power	AURORAxmp (EPIS)
	LADWP	PROSYM (Ventyx)
	NV Energy	PROMOD IV (Ventyx)
	PGE	AURORAxmp (EPIS)
	Tri-State	PROSYM (Ventyx)
Hourly for one week each month	PacifiCorp	PROSYM (Ventyx)
	PNM	PROVIEW (Ventyx)
	PSCo	PROVIEW (Ventyx)
Hourly for one day per month	APS	PROMOD IV (Ventyx)
On-peak and off-peak for each quarter	NPCC	N/A

4.4.2 Production cost models account for changing energy value with increasing penetration

The production cost models used in planning studies account for the reduction in marginal fuel savings as solar penetration grows and the net load becomes lower (i.e., the depth of the dispatch stack). The methods used by most LSEs in the sample therefore account for how adding more solar displaces production from resources with lower and lower variable costs. Consequently, the methods currently used in most LSE planning studies capture changes in the energy value of solar with increasing penetration. However, the studies that use low temporal resolution and lack operational constraints may miss important impacts due to the addition of solar at high penetration levels. Previous detailed analysis shows that it may be important to include high temporal resolution and operational constraints in production cost models to capture the energy value of solar at higher penetration levels (e.g., Mills and Wiser 2012).

The degree to which production cost models included operational constraints on conventional generation (e.g., ramp-rates, minimum generation, start-up time, and start-up cost) differed by study. The CA IOU process, APS, Tri-State, and PGE, for example, used hourly time resolution with a detailed production cost model that included unit-by-unit commitment, ramp-rate limits, start-up time, and minimum generation limits (PLEXOS, PROMOD IV, PROSYM, and AURORAxmp, respectively). The PROVIEW model, on the other hand, uses probabilistic techniques for estimating production costs of different portfolios that will not capture unit-by-unit commitment and constraints. Additional details regarding the capability and limitations of some of these models are described by KEMA Consulting (2003).

Where it is not possible to improve models used in planning studies to capture effects associated with extreme events or operational constraints on conventional generation (for computational or cost reasons), an alternative may be to conduct a side analysis using more detailed models to identify "correction factors" that adjust production costs based on portfolio composition.

Integration cost studies, for example, often identify costs or impacts associated with increased penetration of variable generation that are not captured in the less detailed models used in planning studies. These integration costs are then used to adjust results from the less detailed models such that the costs associated with complex unit-commitment or AS issues are partially reflected in the evaluation of candidate portfolios. This approach can cover many factors not otherwise addressed in the models used in planning studies (see Section 4.5).

Another important consideration for LSEs, particularly as solar penetration increases, is the degree to which the broader wholesale market becomes a market for selling excess power and how much neighboring LSEs procure solar. The degree to which LSEs considered the wholesale power market outside of their own resources or long-term contracts to meet energy needs or as a buyer of power from the LSE's resources varied across studies. PGE clearly included the wholesale power market in the West in its analysis, using the long-term capacity-expansion model AURORAxmp (EPIS) to create a long-term capacity-expansion plan and dispatch for the Western Interconnection.[23] PGE then used this simulated Western wholesale market as an alternative source of energy or buyer of energy from its resources. With such an approach it would be possible to capture the benefit of selling power from solar generation to other markets during times when solar penetration is high for a particular LSE. It would also be possible to evaluate the impact of other LSEs simultaneously increasing solar penetration, which could restrict opportunities to sell excess power to neighboring regions. The CA IOU process and Idaho Power also included the broader wholesale power market by dispatching resources across the entire WECC footprint in their production cost models (although they did not use a long-term capacity-expansion model to create the portfolios for other LSEs outside of their respective regions).

Another method, used by PNM for example, of modeling the wholesale market outside of the LSE region was to use Monte-Carlo based sampling from a historical wholesale price distribution. This approach ensures that events that have historically caused extreme changes in wholesale prices—such as generator failures, exercise of market power, or unexpected weather patterns (factors challenging to capture in production cost models)—are reflected in the distribution of wholesale prices used to evaluate portfolios. However, this approach does not capture potential changes in wholesale price distributions and regional price differences based on evolving factors, such as the increasing role of variable generation in other LSEs' portfolios.

LSE planning studies can be improved by clearly stating whether the broader market is being included in the analysis and, if it is not included, stating why the LSE assumes the broader market is not available to buy and sell power. In cases with increasing amounts of solar generation, LSEs might consider how much solar might be used in other parts of the market too.

[23] The wholesale prices generated by the model, however, are not sufficient to cover the fixed cost of all new investments. PGE states: "Given these assumptions, the AURORAxmp forecasted electricity price is generally not adequate to achieve a positive return of and return on invested capital for new resources. Therefore, it is assumed that costs, particularly for capacity, would need to be recovered through regulation or a separate capacity market."

4.4.3 Planning studies provide little detail on how thermal energy storage dispatchability is captured in production cost models

The planning studies do not appear to include detailed analysis of the potential for CSP with thermal storage to shift solar production to times of most value for a particular scenario. Similarly, few appear to account for the ability of CSP with thermal storage (or natural gas augmentation) to provide ancillary services or reduce the impact of operational constraints from conventional generation.

It is relatively straightforward to treat CSP with thermal storage as having a fixed dispatch profile in a production cost model, assuming that the thermal storage is always dispatched according to typical utility load patterns (e.g., GE Energy 2010). This simple approach ignores the additional flexibility benefits of CSP with thermal storage, including the potential provision of ancillary services. In scenarios with high renewable penetration, the most valuable dispatch pattern of CSP with storage may change. Fully incorporating CSP dispatch into the production cost model can identify the most valuable dispatch patterns for CSP with storage. There are challenges with implementing this in practice since thermal storage is an energy-limited resource—the thermal storage can be "charged" only by the solar field, compared with pumped hydro, which can be "charged" at any time from the grid—and CSP plants must operate above a minimum generation threshold (Sioshansi and Denholm 2010, Brinkman et al. 2012). None of the LSE planning studies describe how the dispatch of CSP with storage is incorporated into the production cost models.

It is easier to incorporate CSP with natural gas augmentation into production cost models. The production of the CSP plant is limited to the available solar profile and the capacity of the power block when natural gas augmentation is not used. When needed, natural gas can be burned in the steam boiler with a very high heat rate. PacifiCorp, for example, uses a heat rate of 11,750 BTU/kWh in its model of CSP with natural gas augmentation. The high heat rate (indicating the relatively low efficiency of burning natural gas to raise steam) suggests that the role of natural gas augmentation is only to increase the capacity value of a CSP plant, not to substantially increase the annual energy output of the plant. Depending on the number of hours per year that are critical for maintaining system reliability, the amount of natural gas burned in a CSP plant with natural gas augmentation can be low while still increasing the capacity credit of the plant.

The relative importance of dispatching CSP with thermal storage is not well known, but initial research indicates there is a benefit (Sioshansi and Denholm 2010, GE Energy 2010, Madaeni et al. 2012b, Mills and Wiser 2012). To capture the full benefits, representation of the dispatchability of CSP with thermal storage may need to be improved in production cost models. Alternatively, LSEs can conduct side analyses that identify the magnitude of the potential benefits from flexibly dispatching CSP with storage relative to a static dispatch profile. These benefits could then be used to adjust the production cost estimates for portfolios with CSP with storage when only a static dispatch profile is used in the planning study (this adjustment would essentially be the opposite of an integration cost that is commonly applied to variable generation resources).

4.5 Adjusting the energy value to account for integration costs

When evaluating portfolios with variable generation, a number of LSEs factored in an integration cost related to resources with increased variability and uncertainty. In some cases, this integration cost was an adjustment to the production cost model results based on an assessment of factors that could not be addressed in the model runs. The reasons the factors could not be addressed directly included limited temporal resolution of the production cost model and/or missing constraints from the model (e.g., day-ahead commitment based on imperfect forecasts or changes in operating reserve requirements for portfolios with more solar). In some cases the justification for integration costs was not stated. Milligan et al. (2011) suggest that, owing to the challenges and common misunderstandings associated with integration costs, such calculations should be conducted carefully, if at all.

4.5.1 Increasing ancillary service requirements in production cost models to account for short-term variability and uncertainty

One approach to accounting for integration costs was to include the need for increased AS requirements directly in the production cost modeling of portfolios with solar.[24] To do this, LSEs used estimates of AS requirements from more detailed studies (or other analysis within the LSE's broader planning study) and then modified the AS requirements in the production cost model for portfolios with solar (a similar process would be used for portfolios with wind). NV Energy, for instance, increased the operating reserve requirement in its production cost model for a portfolio that included solar. The increase in AS requirements was based on a separate detailed study that focused on integrating large amounts of PV into the LSE's system (Navigant Consulting et al. 2011). As part of the CA IOU process, the California Independent System Operator (CAISO), in conjunction with the IOUs and many other stakeholders, estimated the AS requirements and need for additional capacity to meet the increased AS and ramping requirements across different portfolios with renewable energy to meet a 33% RPS by 2020. The increased AS requirements in the production cost modeling implicitly lead to an integration cost embedded in the overall production cost and therefore in the PVRR estimate for each portfolio.

4.5.2 Adding integration cost estimates to production cost results

In other studies, an integration cost for solar was simply added to the production costs for portfolios with solar (as in the Section 3.6 example). The integration costs added to production costs in portfolios with solar ranged from \$2.5 to \$10.9/MWh (Table 6).[25] These integration

[24] Although some LSEs directly increased AS requirements in their production cost model evaluation of different portfolios, none directly evaluated the cost of day-ahead or multiple hour-ahead forecast errors in the production cost model runs. Numerous integration studies that have focused on the technical feasibility of high renewable penetration levels or on estimating integration cost adjustments (as described in Section 4.5.2) have included both AS requirements and the impact of day-ahead forecast errors on production costs.

[25] One LSE planning study, the CA IOU process, also allowed for the increase in operating reserves and variability due to solar (and wind) to potentially increase the need for additional CTs. The degree to which additional CTs were needed due to integration-related needs versus a declining capacity contribution of solar with increasing penetration is still being resolved at the time of the study publication. Additional analysis in the next planning cycle is expected to resolve these ambiguities.

costs were often specified for particular solar technologies but were not evaluated down to the granularity of individual solar projects. Generally, integration costs were assumed higher for PV than for CSP with or without thermal storage, although Tri-State appears to assume the integration costs for CSP with 3 hours of thermal storage are the same as for PV (and wind).

Table 6. Assumed integration costs used by LSEs to adjust production costs for portfolios with solar

Planning Studies	Integration Cost Added to Production Costs ($/MWh)			Notes
	PV	CSP without thermal storage	CSP with thermal storage	
PSCo	$5.15	N/A	$0	
APS	$2.5	$0	$0	
TEP	$4	$2	$0	
Tri-State	$5–$10	N/A	$5–$10	Most scenarios used low end of costs; scenarios with more renewables used higher costs
PGE	$6.35	N/A	N/A	
NPCC	$8.85–$10.9	N/A	$0	Integration costs assumed to escalate up to 2024

Detailed estimates of solar integration costs tailored to address gaps in an individual LSE's production cost model were rare. Rather than conducting studies of solar integration costs, a number of LSEs pointed to other solar integration studies for cost estimates, or used wind integration cost estimates.

PSCo used a solar-specific integration cost study based on its system to estimate integration costs used in its planning study. The integration cost for solar in that study was based on the difference between the production costs over a year with and without day-ahead solar forecast errors. In the case with day-ahead forecast errors, the commitment of non-quick-start generation was based on the previous day's solar generation profile. The actual production costs were then based on dispatching the system with the actual solar generation profile for that day. No other adjustments were made to account for shorter-term variability or AS requirements in the PSCo integration cost study.

4.5.3 Integration cost estimates would ideally be tailored to cover specific limitations in production cost models

Many LSEs could improve their estimates of the integration costs for solar. An LSE's definition of integration cost should ideally match with elements of the production cost model that are left out in order to avoid double counting or missing important components. In fact, the production cost model component of the LSE's planning study could be detailed enough to not need a separate integration cost estimate. With a sufficiently detailed production cost model and study methodology, the LSE could include all elements of variability and uncertainty in the production cost model runs while evaluating portfolios. The approach used by NV Energy and the CA IOU process is a good example: side analyses of AS requirements based on 1-minute load and solar profiles (and wind in California) were used to estimate the additional AS needs for portfolios with increased variable generation. These AS requirements were then directly included in the production cost model used to evaluate the performance of each portfolio.

This detail in analyzing each portfolio under each potential future, however, is still computationally challenging and may not yet be practical for many LSEs. In that case, the integration cost estimate used in the planning can be tailored to the limitations of the production cost models used by the LSE and the characteristics of the LSE's system (in terms of generation and demand-side flexibility, integration with other markets, and deployment of solar).

Given the current variation in LSE systems, tools, and methodologies used in planning studies, different approaches could generate different solar integration cost estimates. The importance of tailoring integration cost studies to fill gaps in the tools used by LSEs means no single integration cost estimate or methodology will necessarily be appropriate for all LSEs.

4.6 Additional factors included or excluded from planning studies

4.6.1 Accounting for the risk-reduction benefits of solar in planning studies

The risk-reduction benefits of solar can be included in LSE planning assessments by accounting for uncertainty in future parameters—such as load growth, fossil fuel prices, and carbon policy—when evaluating candidate portfolios. Many of the planning studies accounted for the exposure of an LSE to changes in assumptions about the future when evaluating candidate portfolios, including portfolios with solar. The risk-reduction benefit of solar could be quantified as the reduced PVRR range for portfolios that include solar, as illustrated by the reduced sensitivity to uncertainties in the "Enhanced Renewable" portfolio in Figure 4. Although this risk-reduction benefit of solar was embedded in the results that LSEs used to identify preferred portfolios, none of the studies specifically isolated the degree to which solar alone reduces a portfolio's overall exposure to uncertainties.[26]

4.6.2 Unique costs or benefits of distributed PV in planning studies

Most LSEs did not distinguish between distributed PV and utility-scale PV or their respective benefits and costs. A few LSEs, however, either explicitly adjusted the PVRR to account for the presumed benefits of distributed PV or implicitly accounted for a portion of the benefits by distinguishing between solar sited near load centers and other forms of generation. Additionally, a few LSEs simply adjusted their peak load and energy forecasts based on estimates of future customer-sited PV. The CA IOU process explicitly included a distribution system cost-reduction benefit for portfolios with large amounts of distributed PV. The estimate of the distribution

[26] It makes sense that LSEs did not attempt to isolate the contribution of particular resources to reducing the overall risk of candidate portfolios since risk is primarily defined in terms of overall portfolios. It would be possible to estimate the risk-reduction benefit of a particular technology, however, by comparing the risk of a portfolio with and without the technology. Estimates of the risk-reduction benefit of particular technologies could then be used to identify which resources to include in portfolios (Step 2) and/or to compare resources during procurement (Step 5).

benefit applied to distributed PV varied by location but was most often around $5/MWh (with a range of $4.3 to $26.2/MWh). An earlier analysis of the benefits of distributed PV conducted for APS (R.W. Beck 2009) found avoided distribution costs from distributed PV of $0 to $3.1/MWh, although these benefits were not explicitly mentioned in the APS planning study. In some studies, transmission expansion was required for portfolios with new distant resources, while less was required for portfolios with solar sited closer to load.

Distributed PV can also reduce transmission line losses. Production cost models with transmission network representation can account for reduced transmission losses when solar is located near major load centers (e.g., Lin 2012). The portfolios that included PV in major load zones would therefore reduce line losses in the production cost models, which would then reduce the PVRR for that portfolio, if the LSEs evaluated transmission line losses when evaluating portfolios. It is challenging to model line losses in production cost models, however, particularly when looking out many years to when the transmission network configuration may not be known. Furthermore, production cost models generally do not account for changes in losses in distribution systems, which means the impact of distributed PV on distribution line losses would be ignored in the studies that did not explicitly quantify these impacts. Although it is possible to estimate the impact on line losses of distributed PV (or the increase in losses from additional generation sited far from load centers), most planning studies did not appear to account for changes in line losses for different portfolios. If line losses are not accounted for directly in the production cost models, then approximation methods that account for the non-linear relationship between line loading and losses can be used to estimate the line-loss reduction benefit of distributed PV (e.g., Borenstein 2008, R.W. Beck 2009).

The transmission and distribution (T&D) impacts of distributed PV are complex and sensitive not only to penetration levels but also to a wide variety of localized factors (e.g., Shugar and Hoff 1993, Cossent et al. 2011, Katiraei and Aguero 2011). The cost impacts can be positive or negative. More LSE planning studies would ideally account for the costs and benefits of distributed PV on the T&D system as PV deployment increases and as tools to estimate these impacts improve.

4.6.3 Options to mitigate output variability and uncertainty of solar in planning studies

None of the planning studies in the sample explicitly identified synergistic benefits between PV and CSP or between solar and wind in portfolios.[27] Such benefits may have been implicitly recognized in production cost modeling where portfolios had combinations of renewable resources, but nothing was mentioned with respect to adjustments to integration costs or the capacity credit of technologies. The capacity credits for wind, CSP with thermal storage, and PV estimated in the Western Wind and Solar Integration Study showed a slight synergistic effect: the

[27] The methodology used by the California Public Utilities Commission to calculate the qualifying capacity for solar and wind projects contracted or owned by the IOUs (the resource adequacy or RA program) does include a diversity benefit. This approach is used in accounting for the qualifying capacity of projects once built; it does not appear to be used in the planning study. In the RA program, the diversity benefit is defined as the difference between the qualifying capacity estimated for all wind and solar resources combined less the sum of the qualifying capacity estimated for each wind or solar project individually. This diversity benefit is allocated to each wind and solar project on a per-energy-unit basis (CPUC 2011b).

capacity credit for all three resources combined was 0.3 to 0.7 percentage points greater than the sum of the capacity credit of each resource alone (GE 2010). On the other hand, analysis of the capacity credit of wind and solar combinations in the Western Interconnection by Ibanez and Milligan (2012) appears to indicate a slight reduction (2.5 percentage points) in the capacity credit from the combination of 29 GW of wind and 14 GW of solar, enough to meet 8% and 3% of the annual WECC energy demand, respectively, relative to the capacity credit of each technology in isolation.

A number of LSE planning studies included several technologies that might be more attractive in scenarios with high solar penetration. Aside from including natural gas augmentation and thermal storage in CSP plants, for example, some LSEs included batteries with PV. PNM included a 1-MW PV system coupled with a lead-acid battery. PSCo added batteries to manually created renewable portfolios with PV. In contrast to a coupled battery and PV system, the operation of the battery in the PSCo portfolio was not coupled to the operation of the renewables; both the battery and renewables could be dispatched in a manner than minimized system costs. In the PNM and PSCo cases, any additional value from including the battery was not found to be sufficient to make up for its high cost. Other LSE studies included compressed air energy storage and pumped hydro as potential resource options. Though many studies identified demand response as a potential resource in portfolios, none of the studies appeared to directly consider the role of demand response in increasing the value of solar.

4.7 Designing candidate portfolios for planning studies

Although the overall framework used by many LSEs in planning studies can capture many drivers of the economic value of solar, ultimately only portfolios created and evaluated within this framework can be selected as a preferred portfolio. A number of LSEs used detailed methods to *evaluate and select* the preferred portfolio from the various candidates, but they did not always use such sophisticated methods to *create* candidate portfolios in the first place. Creating candidate portfolios for further study, Step 2 described earlier in Section 3.2, is critical to determining if a portfolio with solar (and/or other resources) is the least-cost or most attractive portfolio. A similar point was made by Wiser and Bolinger (2006). As such, to the extent that LSEs decide to include solar as a key potential future resource option, they should ensure varied amounts are included in a diversity of candidate portfolios, with different solar configurations and different technologies. Only by including a wide diversity of well-constructed candidate portfolios with solar can the costs and benefits of solar be properly evaluated.

In particular, studies that manually create relatively few portfolios (often less than 10) for further analysis may be ignoring potentially promising portfolios with lower PVRR or risk. The earlier simple example presented in Section 3.6 illustrates the importance of using well-designed portfolios to identify the potential contributions of solar. If portfolios are manually created, it is better to create a wide range of portfolios with various combinations of resources rather than evaluating few portfolios. Roughly half of the planning studies reviewed did not use a capacity expansion model at any point in the study to assist in the creation of candidate portfolios. One of these planning studies, as further illustration of the point, only evaluated high solar penetration in a portfolio that already included other low-carbon (but potentially high-cost) resources. A portfolio with a mix of solar and fossil fuel resources might have been more attractive than this low-carbon portfolio and perhaps even lower cost than the preferred portfolio. Without first creating and then evaluating such a portfolio, however, it is impossible to make the comparison. To address this, LSEs can use capacity-expansion models to create candidate portfolios or guide the creation of candidate portfolios instead of doing it manually.

4.7.1 Commercially available capacity-expansion models used in planning studies

A number of LSEs used commercially available capacity-expansion models to create feasible portfolios (Table 7). These models appear to be useful for automatically screening hundreds or even thousands of combinations of resource options to identify the least-cost option for a given set of deterministic assumptions about the future (i.e., assuming future parameters are known with perfect foresight).

In addition, "bookend" portfolios were then sometimes created using capacity-expansion models by identifying least-cost portfolios for extreme assumptions about the future. For example, rather than manually creating a low-carbon portfolio, a capacity-expansion model was used to identify a least-cost portfolio out of the large number of potential resource combinations under an assumption of very high carbon prices. In some cases, several different least-cost portfolios were created by the LSE by rerunning the model with different future assumptions, and then these candidate portfolios were evaluated in greater detail (Step 3, Section 3.3) and compared (Step 4, Section 3.4).

Table 7. Capacity-expansion models used by LSEs considering solar

LSE/planning entity	Capacity-expansion model
Duke Energy	System Optimizer, Ventyx
El Paso	Strategist, Ventyx
NPCC	Regional Portfolio Model[28]
PacifiCorp	System Optimizer, Ventyx
PNM	Strategist, Ventyx
PSCo	Strategist, Ventyx
TEP	Capacity Expansion,[29] Ventyx
Tri-State	System Optimizer, Ventyx

Though the use of capacity-expansion models to create candidate portfolios is likely superior to manual creation of candidate portfolios, it is important that the capacity expansion models have the capability to recognize the costs and benefits of various resource options. Some commercial capacity-expansion models could be improved by increasing the temporal resolution and better accounting for operational constraints, which affects the energy value of resources and in turn impacts the degree to which the models will find the inclusion of a resource attractive in terms of minimizing PVRR. A previous review of commercial and non-commercial models available to identify the sizing and placement of storage, including thermal storage, made similar recommendations for improving currently available software (Hoffmann et al. 2010). Sioshansi et al. (2012) similarly noted limitations of capacity-expansion models in recognizing the full

[28] Regional Portfolio Model is an in-house, Excel-based capacity-expansion model.

[29] Capacity Expansion is a precursor to the System Optimizer model.

value of bulk power storage, particularly with respect to the dynamic benefits associated with the provision of AS and ramping over various time frames. Proper representation of the temporal generation profile of solar, the capacity contribution of solar (and changes in that contribution with penetration), and the integration costs of solar in capacity-expansion models are important to valuing solar correctly in these models. Similarly, accurate accounting of the capabilities of thermal storage and natural gas augmentation is important for CSP. A growing body of research examines methods for incorporating operational constraints and high temporal resolution into models that can be used for capacity expansion without greatly increasing the computational complexity (e.g., Müsgens and Neuhoff 2006, Neuhoff et al. 2008, Palmintier and Webster 2011, Staffell and Green 2012). Such improvements may not be in commercially available models used by many LSEs, and are areas for possible future improvement.

An alternative to modifying the capacity-expansion model software is to estimate adjustment factors for various technologies based on an evaluation in more detailed production cost models or other models that account for these factors. Differences in the value of a resource evaluated using a detailed production cost model compared to the value estimated with the simpler capacity-expansion model could be applied as adjustment factors to resources in the capacity-expansion model. PSCo, for example, developed estimates of coal cycling costs with increased wind penetration (amounting to an incremental cost of about $2.2/MWh when increasing wind from 2 to 3 GW) to include in the Strategist capacity-expansion model (Xcel Energy 2011). Without these adjustments, the cost of cycling coal plants would not have been included in the evaluation of wind resources in the capacity-expansion model. Done appropriately, these adjustment factors should always be tailored to address the gaps in an LSE's modeling approach or capacity-expansion model.

A further improvement to the commercial capacity-expansion models would be to account for risk (and uncertainty) directly in creating a portfolio with the lowest expected cost (as opposed to identifying a portfolio that is only least-cost under the particular set of assumed deterministic model inputs). The approach used by some LSEs already emulates this decision-making process through multiple steps. The NPCC approach, however, appeared to be unique in considering uncertainty in the creation of the optimal portfolio from a single capacity-expansion model. In contrast to other models that assume perfect foresight, the NPCC's in-house Regional Portfolio Model identified an expected least-cost portfolio assuming uncertainty in future parameters like fuel and carbon prices. The model was further used to identify the least-cost portfolio for a specified level of acceptable risk exposure. NPCC refers to this process as "risk-constrained, least cost planning." The NPCC model is similar to an advanced stochastic capacity-expansion planning approach described by Jin et al. (2011).

4.7.2 Ranking resource options based on net cost

For LSEs that cannot rely on commercial capacity-expansion models to create feasible portfolios, simple methods to identify which resources are most likely to minimize PVRR can be used to rank potential resources. We derive a method to calculate how including any resource in the least-cost portfolio affects the PVRR, based on finding the "reduced cost" of the resource capacity variable in the optimal solution to the planning problem (see Appendix B for details). The term "reduced cost" is used in linear optimization (Bertsimas and Tsitsiklis 1997), but in this document the resulting metric will be referred to as the "net cost" of a resource for consistency.

LSEs differ in what factors are important in the screening of resources based on net cost. For illustration, we focus on a simple form of this formula that only considers the capacity value and energy value assuming perfect foresight. Based on the same concept, the net cost formula can be expanded to include other factors in the avoided cost such as T&D costs, integration costs, or risk-reduction benefits. In the simplest form, this formula is as follows:

Net cost ($/MWh) = Resource Delivered Cost ($/MWh) – Avoided Costs ($/MWh)

Where:

- Net cost ($/MWh) is the change in the expected PVRR if a resource were required to be included in the preferred portfolio.
- Resource Delivered Cost ($/MWh) is the cost the LSE would pay to obtain the power from the resource, delivered to the LSE's loads.
- Avoided Costs ($/MWh) is the combination of the capacity value ($/MWh) and the energy value ($/MWh).
- Capacity value ($/MWh) is the avoided cost of capacity based on the capacity contribution of the resource toward a resource adequacy requirement:

$$Capacity\ Value\ (\$/MWh) = \frac{FC_{peak}}{8760\ h/yr}\frac{CC_s}{CF_s}$$

  - Where:
    - FC_{peak} is the annualized fixed investment cost of a peaker plant ($/MW-yr).
    - CC_S is the capacity credit of the solar plant (% of name plate).
    - CF_S is the capacity factor of the solar plant (%).
- Energy value ($/MWh) is the avoided production cost based on the coincidence of generation from the resource and wholesale power prices (or system lambdas):

$$Energy\ Value\ (\$/MWh) = \frac{\sum_t p^t E_s^t}{\sum_t E_s^t}$$

  - Where:
    - p^t is the hourly wholesale energy price or marginal production cost (a.k.a. the system lambda, $/MWh).
    - E_S^t is the hourly solar production (MWh).

This same concept can be applied to calculate the net cost of a conventional generation option. The primary difference between the calculation for a conventional resource and a solar plant is in the estimation of the energy value (as described in Appendix B).

Ranking resources using this net cost method has the advantage of being defined with respect to the objective of minimizing PVRR. In addition, this approach does not require defining "back-up" capacity adders or other adjustments that are not otherwise part of the broader LSE portfolio creation or evaluation process.

The formula used to estimate the net cost above is similar to the ranking cost formula used in practice by the CA IOU process and LADWP to create candidate portfolios (Figure 9). A similar ranking approach was used to highlight economically attractive resources in the California Renewable Energy Transmission Initiative (RETI) (Black & Veatch 2008) and the Western Renewable Energy Zone Initiative (WREZ) (Mills et al. 2011). The net cost ranking uses somewhat similar logic to the approach advocated by Joskow (2011). This approach to ranking resources based on the net cost closely parallels the process described in Section 3.6, where the net cost of a resource is the difference between its levelized cost and its avoided cost. This approach also mirrors the economic evaluation process that a number of LSEs appear to follow during the evaluation of bids in the resource procurement process (described in the next section). Based on this, the net cost ranking approach seems to be a defensible and understandable way to screen and rank resources during the creation of candidate portfolios, especially when more advanced capacity expansion models are not available to serve that purpose.

$$Energy\ Value\ (\$/MWh) = \sum[(Energy\ Value\ in\ Time\ Period) \times (Energy\ Output\ in\ Time\ Period)]\ / \ Total\ \ Energy\ Output$$

$$Capacity\ Value\ (\$/MWh) = (Dependable\ Capacity\ Factor) \times (Baseline\ Capacity\ Value)\ / \ (Project\ Capacity\ Factor\ \times\ 8760/1000)$$

Figure 9. Capacity value and energy value formulas used by LADWP to rank resources

4.7.3 Ranking resource options based on other approaches used in practice

In a few cases, LSEs compared resource options based on their levelized costs, along with a number of cost adders that can make certain resources appear less attractive (Figure 10). The adders include transmission costs, integration costs, and capacity-related adjustments. The transmission cost adder simply adds the estimated cost of delivering the resource to the LSE. Transmission cost adders are higher for distant resources with low line utilization relative to resources assumed to be close to the LSE (or with high line utilization).

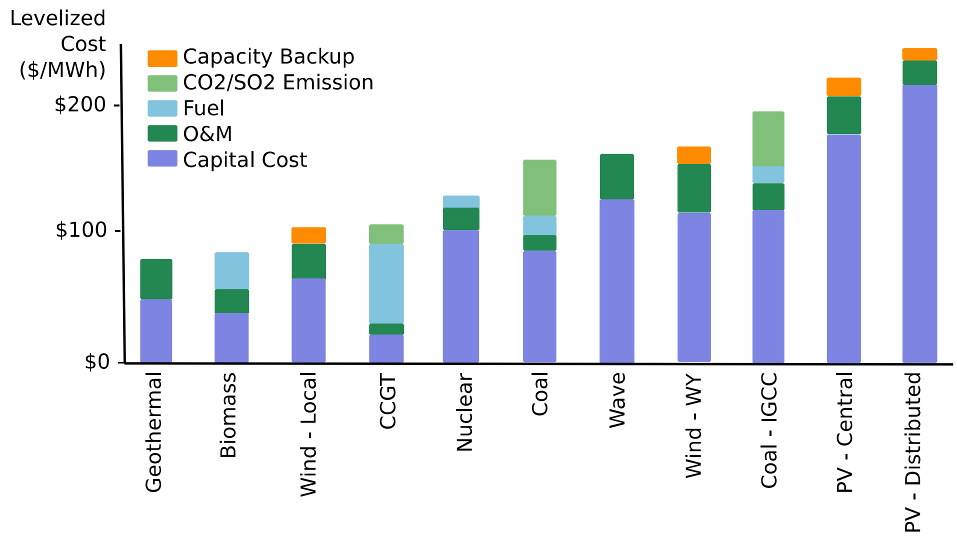


Figure 10. Example of ranking by levelized cost with capacity adder (adapted from PGE)

Integration cost adders are typically based on the uncertainty and variability of variable generation technologies. When included and explicitly stated, the integration cost adders used in resource ranking ranged from $2.5/MWh for APS to $8.25/MWh for NPCC (based on previous estimates of the integration costs for *wind* in that region). One outlier was SRP's very high integration cost adder of $45/MWh applied to the cost of PV. No clear justification was presented for this high integration cost, nor does this high cost appear to be supported by other analysis in the literature.

Text Box 2. Comparison of capacity cost adders used by LSEs to adjust levelized cost

The basis for the capacity-based adders used by LSEs to screen resources for possible inclusion in candidate portfolios was usually not well described in the planning documents, aside from reference to the lower capacity credit of solar relative to its nameplate capacity. One LSE that did justify its capacity adder to the levelized cost of PV in ranking the resource options was PGE. It adjusted the levelized cost of wind and PV to make the capacity comparable to an energy-equivalent comparator plant (CCGT). The resulting *energy-equivalent* capacity adder for PV with a 5% capacity credit was about $10/MWh. The capacity cost adjustment based on an energy-equivalent comparator plant has similarly been used in a detailed review of the wind integration literature (Gross et al. 2006) and applied to a comparison of wind and a thermal power plant (Söder 2005).

In other planning documents where the basis for the capacity adder was not as clearly justified, the adders ranged from $25/MWh for APS to $47/MWh for TEP, even though the capacity credits for solar in those cases were greater than the 5% capacity credit for PV assumed by PGE. In contrast to the energy-equivalent adder used by PGE, the high-cost examples from APS and TEP appear to be based on the cost of additional capacity resources required to bring solar from its normal capacity credit to a capacity credit of 100%. We refer to this as the *capacity-equivalent* capacity adder to highlight that it makes the contribution to resource adequacy the same as a conventional plant, but the energy generated by the resource is not equivalent to any other particular conventional plant.

To illustrate the differences between an energy-equivalent capacity adder and a capacity-equivalent capacity adder, we walk through a calculation of these adders using assumptions that appear similar to those used by LSEs in particular planning studies.

Energy-equivalent capacity adder:
PGE adjusted the levelized cost of each resource option to make the resource comparable to an energy-equivalent comparator plant (CCGT). It started with noting, for example, that a 100-MW CCGT operated at a 92% capacity factor would provide 800 GWh/yr of energy and contribute 100 MW toward the resource adequacy requirement. A 540-MW PV plant with a 17% capacity factor would also provide 800 GWh/yr of energy, but the PV plant would only provide 27 MW of capacity owing to PGE's assumed 5% capacity credit for PV. To have a PV plant that produces 800 GWh/yr of energy also contribute 100 MW toward resource adequacy, an additional 73 MW of CT capacity would need to be added to the portfolio. At a CT cost of $100/kW-yr, the cost of the additional 73 MW of capacity would add $9/MWh to the levelized cost of PV—similar to the capacity adder used by PGE.

Capacity-equivalent capacity adder:
In contrast, the capacity cost adder for PV used by TEP appears to be based on adding the cost of 67 MW of additional CTs for each 100 MW of PV with a 33% capacity credit. Assuming the cost of capacity is $100/kW-yr and that TEP would need to add 67 MW of capacity for each 100 MW of PV, the capacity adder would work out to be $45/MWh for PV—similar to the $47/MWh capacity cost adder actually used by TEP.

Although there is disagreement between the LSEs regarding the calculation of capacity adders, the capacity-equivalent capacity adders appear to be higher than can logically be justified since the values do not follow the type of behavior that would be expected based on other detailed analysis of the economic value of solar.

In a few cases, particularly as LSEs were justifying which resources to include in candidate portfolios, LSEs translated the lower capacity credit of solar relative to its nameplate capacity into a capacity cost adder. PGE based this capacity cost adder on the cost of CTs that would be required to make the capacity contribution of PV and CTs equivalent to the capacity contribution of an energy-equivalent comparator plant (Text Box 2). PSCo used somewhat similar logic in its adjustment of the levelized cost of all resources into an energy- and capacity-equivalent basis (Text Box 3). While the energy-equivalent adjustment approach has been described and employed previously in the broader literature with wind energy, it not as intuitive or as clearly linked to the objectives of the planning studies as the estimate of the net cost of a resource. In contrast, the net cost approach can be clearly linked to the objective of finding portfolios with the lowest PVRR.

In other studies, LSEs developed capacity cost adders that appear to be much higher than would be expected using an energy-equivalent comparator plant approach. These studies did not clearly specify how they developed the capacity cost adders, but this high cost is not reconcilable with literature on the capacity value of solar at low penetration levels (Text Box 2). These LSEs could develop more representative rankings of eligible resources by shifting to a net cost method (e.g., the current practice for the CA IOU process and LADWP) or at least an energy-equivalent method for comparing different resource options (e.g., the current practice for PGE and PSCo). For clarity and consistency with the objectives of the planning studies, we recommend the use of net cost for ranking resource options.

The risk-reduction benefits of solar were not included in any of the methods used to rank resources when LSEs created candidate portfolios for evaluation. In contrast, one LSE (SRP) applied a risk cost adder to solar and other technologies based on uncertainty about future solar capital costs. This cost adder appears to be unfounded given that capital costs will be relatively well known at the time contracts are signed to build or procure a solar resource. Costs such as natural gas prices or carbon prices in 10–15 years, on the other hand, are comparatively much more uncertain, and power plants must be procured before resolving uncertain future fuel and carbon prices.

Text Box 3. PSCo's energy- and capacity-equivalent levelized cost approach

PSCo used a commercial capacity-expansion model to create its baseline, least-cost portfolio for a given set of assumptions about the future. It then developed eight alternative renewable portfolios to compare to the least-cost portfolio. In deciding which resources to add to those alternative portfolios, PSCo ranked all potential resources based on adjusting the levelized cost of each resource. The adjustments attempted to account for differences between renewable technologies by putting each of the levelized cost estimates on an energy- and capacity-equivalent basis.

The adjustments to the levelized cost of each resource proceed as follows. First, the resources are made to each produce the same amount of equivalent energy over the year, equal to the annual output of an annual flat block of power with the same nameplate capacity as the resource, by adding "system energy" to the energy produced by the resource. The cost of the system energy is estimated as the energy from a CCGT with a 7,000 MMBTU/MWh heat rate and a specified natural gas price (which works out to be $50/MWh). Then the resources are made to produce the same amount of capacity by adding sufficient new CTs to give the resource a capacity credit equivalent to its nameplate capacity. The total cost of the resource plus the system energy and the additional CT capacity are then divided by the annual energy from the flat block to arrive at the adjusted levelized cost. Table 8 shows the results of this adjustment from the appendix of the PSCo planning study. In this case, the levelized cost of PV is far greater than the levelized cost of wind, but PV has a higher capacity credit per unit of energy than wind. The energy- and capacity-equivalent levelized cost is therefore about equal between wind and PV.[i]

Table 8. Energy- and capacity-equivalent levelized cost example (adapted from PSCo)

Resource	Capacity factor (%)	Capacity credit (%)	Levelized cost ($/MWh)	Energy- and capacity-equivalent levelized cost ($/MWh)	Ranking (lower is better)
CSP with thermal storage (10% ITC)	38	100	223	115	5
PV (30% ITC)	30	55	102	69	3
Wind (no PTC)	45	12.5	76	69	3
CCGT	45	100	81	64	2
CT	10	100	160	60	1

[i] One limitation with this approach is apparent from the comparison of a CT and a CCGT on an energy- and capacity-equivalent basis. In general, a CT has a lower fixed cost than a CCGT, but a CCGT is more efficient. If an LSE needs a new intermediate or baseload generator, the total costs will be lower if the LSE pays a higher fixed cost to buy the CCGT since it will then be able to produce lower-cost energy. On the other hand, if the new generator will only be needed in rare instances, the total costs will be lower if the LSE pays the lower fixed cost to buy a CT and only uses a small amount of fuel to run the CT infrequently. The PSCo energy- and capacity-equivalent levelized cost, however, assumes that the LSE can get unlimited "system power" with the efficiency of a CCGT and low-cost capacity from a CT. Since the capacity contribution of the CT and CCGT is the same but the fixed cost of the CT is lower (and the CT can rely on unlimited cheap system power), the CT will automatically appear to be a better choice than the CCGT based on this capacity- and energy-equivalent levelized cost approach. This may make sense if the LSE has excess, low-cost "system power," but it is not generally applicable to all areas.

ITC = investment tax credit; PTC = production tax credit

4.8 Economic evaluation of bids in procurement processes

After identifying candidate portfolios, evaluating those portfolios, and selecting a preferred portfolio, a number of LSEs issued RFPs for generation projects that would either be owned by the LSE or would operate under a long-term contract with the LSE (i.e., a power purchase agreement [PPA] or a tolling agreement). These RFPs almost always provided guidance to bidders regarding the approach the LSE would use to evaluate the attractiveness of each bid based on economic and non-economic (commercial readiness of technology, experience of development team, etc.) factors. This section only covers the methods used to evaluate bids based on economic criteria.

4.8.1 Most LSEs in the study sample appear to rank bids based on *net cost*

Almost all of the RFPs considered in the survey appeared to evaluate the economic attractiveness of bids by estimating the *net cost* of each bid. In some cases the net cost would be calculated directly using approaches similar to those used in the planning studies. Namely, the net cost would be the difference between the PVRR for the LSE's most recent IRP's preferred portfolio and the PVRR if the resource in question were included in the portfolio. Bids with the lowest net cost would be the most economically attractive (but not necessarily the most attractive overall since many RFPs included non-economic factors too).

In other cases, the LSE estimated the net cost as the respondent's bid cost plus any adders less the benefits of the power from that bid. The adders for solar often included an integration cost adder and in some cases a transmission cost adder. The transmission cost would include any transmission expenditure by the LSE to deliver the solar from its point of delivery to the LSE load area. Any transmission expense for the solar energy to be delivered from the point of grid interconnection to the point of delivery to the LSE was typically included by the RFP respondent in the bid cost. Similarly, the integration cost adder was used only for the cost of the LSE integrating the solar into its system, while any charges by other entities to schedule solar deliveries were included by the respondent in the bid cost. The range of integration cost adders reported in RFPs was within the same range used in portfolio creation and portfolio evaluation reported earlier.

The benefits of the power from the bid typically included an energy value and a capacity value. It was often not clear how the capacity value would be calculated in the evaluation process, although many LSEs described how the capacity credit would be estimated for each bid (or what capacity credit would be assigned to each bid). The energy value would often be estimated as the product of the bidder's generation profile and the wholesale power prices estimated from the LSE's most recent planning study. The temporal resolution of the bidder output profiles requested by the LSEs in the RFPs varied. A 24-hour average daily profile for each month (12 X 24) and a full 8,760-hour time series were commonly used.

For RFPs that sought only RECs or allowed unbundled RECs to compete with bidders that would also deliver power to the LSE, the integration and transmission cost adders of unbundled RECs would be zero, and the benefits would also be zero. The net cost of the unbundled RECs would therefore simply be the bid cost of the RECs, which could be directly compared to the net cost of respondents that provided both RECs and power.

None of the RFPs appeared to use a simplistic economic evaluation method of ranking bids from different resources based only on the lowest bid cost. However, some RFP documents did not specify in detail how the LSE would conduct an economic ranking. Southern California Public Power Authority (SCPPA)—an authority that assists LADWP and other public utilities recently subject to California's 33% RPS by 2020 with procuring renewable resources—only requires a bidder to provide a bid price, maximum and minimum monthly capacity factors, seasonal production shapes, and a description of the project's dispatchability to describe the generating characteristics of its proposed project. SCPPA then indicates that it reserves "the right to make an award to an offer with higher than lowest price offered, or the proposal evidencing the greatest technical ability or other measure, if SCPPA determines that to do so would result in the greatest value to SCPPA and its Member Agencies." No indication is provided by SCPPA as to how it would estimate the value of a bid, suggesting that its evaluation approach lacks detailed quantitative comparisons of the economic value of different bids.

In one case, PSCo, the LSE inputs the characteristics of all bids that pass an initial economic screening into a commercial capacity-expansion model (Strategist) and then uses the model to select the portfolio of bids that minimizes the PVRR. In this case, the merits of each bid are never estimated in isolation; rather the bids are only selected if they, in combination with other bid-in resources, minimize the PVRR. The capacity credit of solar resources used in the capacity-expansion model was based on PSCo's own capacity credit study. As mentioned in Section 4.7.1, this approach to using a capacity-expansion model to evaluate the economic attractiveness of individual bids could be designed, as much as is practical, to account for factors that are not evaluated in the capacity-expansion model (e.g., integration costs, dispatchability of thermal storage, etc.).

In contrast to the widespread consideration of risk in evaluating candidate portfolios in the planning studies, risk was not prevalent in the economic evaluation of bids for most LSE procurement practices. One exception was PSCo. Portfolios of resources bid in response to the PSCo RFP were evaluated under a range of sensitivities, including different natural gas fuel prices, carbon prices, and construction cost escalation rates. Other LSEs may wish to consider ways to embed risk evaluation in ranking of bids.

4.8.2 Lack of detail on economic evaluation can hinder respondents' determination of best technology/configurations

Most LSE procurement practices appear to evaluate the economic merits of individual bids based on the LSE's estimate of the net cost (bid cost less the benefits of the power generated by the resource). This overall framework for ranking bids appears to be a best practice.

That said, there is wide variation in the ways that LSEs appear to calculate the net cost (particularly regarding the estimate of benefits to the LSE of the power generated by a bidder) and little detail on the exact methods used by different LSEs. The lack of detail may be in part due to the additional challenges associated with estimating the avoided cost of variable generation like solar relative to conventional generation, a concern highlighted in a previous survey of utility procurement practices (SEPA 2009). The lack of detail may also be due to the practice of some LSEs working closely with promising bidders to identify the most attractive configuration after initially screening bids at a high level using the RFP process. With larger and more competitive solicitations, however, LSEs may not have the opportunity to work closely with all promising bidders to refine their projects after the initial screening. The lack of detail in the RFPs makes it more difficult for a respondent to determine the most attractive configuration for its project (on a net cost basis). Without detail on how the LSE's hourly marginal production cost is expected to vary throughout the year or which hours of the year drive the need for new capacity, it is difficult to know which PV orientations or tracking technologies are most attractive. The bidder can easily estimate the impact of the choice on its own bid cost but cannot as easily ascertain the impact on the overall net cost (bid cost less benefits to the LSE). In the same manner, it is difficult to know whether using multiple hours of thermal storage with CSP will increase or decrease the net cost of a bid.

Several options might help address these concerns:

(1) The LSE could evaluate the avoided cost of several different solar options and technologies in its planning studies relative to its preferred portfolio. The LSE would then make those estimates available to the market in the RFP or in the LSE's planning studies. RFP respondents could then use those estimates of avoided costs and its own estimates of the impact of different solar configurations and technologies on the bid cost to respond to the RFP with a bid minimizing the net cost.

(2) The LSE could publish information detailing how it will estimate the avoided cost of each bid along with the parameters the LSE will use in the bid evaluation so that a bidder can conduct its own estimate of the expected avoided cost for different solar configurations or technologies. This might include indicating the hourly marginal production costs over future years for the preferred portfolio that the LSE will then use to estimate the energy value component of the avoided cost for each bid. It might also include the estimated cost of capacity for the preferred portfolio and the periods of the year that drive the need for additional capacity.

(3) The LSE could publish only a detailed description of the technical approach that it will use in estimating the avoided cost of individual bids. Each bid respondent would be required to recreate the preferred portfolio of the LSE and estimate the avoided cost of its resource.

This last approach most closely resembles the current situation in many RFPs, although there are cases in which the LSE is ambiguous even regarding the technical details of evaluating the avoided cost of individual bids. An earlier review of utility procurement practices related to solar noted that in this approach the developer is often left to quantify and monetize the benefits of its bid to the utility and then highlight those benefits to the utility in its RFP response (SEPA 2009). Essentially, this situation puts the onus on project developers to understand all of the factors potentially affecting the LSE's valuation of a project over a multi-decade planning horizon and then translate this into an estimate of the avoided cost of potential solar technologies or project configurations that could be bid into the procurement process. Without any clear understanding of how the value would vary across options, developers would be more likely to simply minimize the levelized cost of their bid or submit many similar bids with slightly different configurations, which the LSE would then have to evaluate.

The first two options better inform a bidder during its technology selection and configuration process, with the LSE playing a more direct role in informing the market of what type of generation product would be most valuable. The developer could focus on developing bids that maximize the value to the LSE (i.e., minimize the net cost) rather than focusing on recreating the LSE's estimate of economic value.

As an example of what the first option might look like in practice, the California Public Utilities Commission (CPUC) developed and made publicly available a spreadsheet tool that estimated the net cost of various renewable resource options as part of the CA IOU process (E3's 33% RPS Calculator). In this case, however, the tool was only used for developing portfolios of resources that were evaluated in the CA IOU process (the estimates of the benefits or avoided cost of each option in this spreadsheet tool were not used to evaluate bids during resource procurement). Ideally, an LSE estimate the avoided costs of different options, provide those estimates of avoided costs to bidders, and then use those same values in the economic evaluation of bids during the procurement process.

Finally, this first option (with the LSE providing avoided cost estimates for different resource types, configurations, and locations) may be easier to implement than the second option (with the LSE providing all the detailed parameters needed to calculate the avoided cost of any bid) because the second option may require the LSE to publicly release confidential or sensitive market information.

5. Conclusions and Recommendations

As renewable technologies mature, recognizing and evaluating their economic value will become increasingly important for justifying their expanded use. We found that many LSEs have a framework to capture and evaluate solar's value, but approaches varied widely: only a few studies appeared to complement the framework with detailed analysis of key factors such as capacity credits, integration costs, and tradeoffs between distributed and utility-scale PV. Factors like the dispatchability benefits of CSP plants with thermal storage appear to be quantified only in terms of a higher capacity credit versus other solar technologies. As the cost of building solar decreases, it will become increasingly important to refine estimates of these factors for all solar technologies, refine study methodologies, and communicate those methodologies to developers and generating equipment manufacturers. In summary we found the following:

- *LSEs should seek, over time, to ensure that solar is included in varied amounts, with different configurations, and for different technologies within a diverse mix of candidate portfolios to ensure a full evaluation of the costs and benefits of solar energy*. Only resources that are fully evaluated within the overall framework can be identified as preferred resources. While some down screening of resource options is warranted to reduce the complexity of the portfolio evaluation process, crude screening can prematurely exclude options that could be attractive with more detailed analysis.

- *Many LSEs can improve their design of candidate portfolios, particularly regarding the methods used to rank potential resource options.* Capacity-expansion models that can represent the costs and benefits of solar technologies should be considered for identifying candidate portfolios, if regulatory and budgetary constraints allow. If that option is not available to an LSE, then the net cost ranking method (as further supported in Appendix B) is a reasonable alternative. The net cost represents an estimate of the change in the PVRR from including a particular resource in the portfolio that would otherwise minimize the expected value of the PVRR. This logical connection to the objective of many planning studies and procurement practices makes the net cost approach attractive for ranking resource options or evaluating the economic merits of RFP bids. A similar net cost ranking approach is used by LADWP and the CA IOU process to select resources that make up candidate portfolios. The net cost method is clearly more defensible than ranking resources based only on levelized costs, and it is potentially easier to connect to the portfolio evaluation process than options that start with levelized costs but then make adjustments such as capacity cost adders. In addition, it appears there is disagreement among the methods used to estimate capacity cost adders: some LSEs are using capacity-equivalent capacity cost adders while others use energy-equivalent capacity cost adders.

- *Planning studies account for the capacity value of solar, but many LSEs can improve their estimates of the capacity credit of different solar technologies at varying penetration levels.* Planning studies accounted for the capacity value of solar by reducing the need to provide capacity through other means, often a CT peaker plant. Most studies accounted for the differential load-carrying capability of PV and CSP without thermal storage relative to CSP plants with thermal storage and/or natural gas augmentation. Only APS, however, appeared to account for changes in the capacity credit of solar with increasing penetration levels. Studies that assume a fixed capacity credit will not recognize one of the main benefits of adding thermal storage or natural gas augmentation to CSP plants—the ability to maintain a high capacity credit even with higher solar penetration levels. In general, few LSEs used detailed analysis of their systems or the broader region to support estimates of the capacity credit of solar. LSEs could improve their planning studies through more attention to capacity credit estimates for different solar technologies, configurations, and penetration levels.

- *Most LSEs have the right approach and tools to evaluate the energy value of solar, but improvements remain possible.* The studies accounted for the energy value of solar by analyzing the ability of solar to reduce variable costs with detailed production cost models. These models can account for both the correlation of high solar production with times of higher production cost in many regions and the potential for the incremental energy value of solar to decrease with increasing penetration. Evaluating portfolios under a wide range of forecasts regarding uncertain parameters like future fuel and carbon costs demonstrates the degree to which solar resources can reduce exposure to these risks. High temporal resolution (hourly) in the production cost model, inclusion of operating constraints on conventional generation resources (ramp rate limits, start-up costs, minimum generation limits, etc.), and attention to the broader wholesale market outside of the LSE's own resources are important for proper evaluation of the energy value of solar, particularly as the penetration of solar increases. These factors are all represented in more detail in production cost models than in capacity-expansion models. Capacity-expansion models can be improved by increasing the fidelity of the model to represent many of the factors accounted for in more detailed production cost models (while recognizing the need to maintain a reasonable computational complexity). In lieu of changing the capacity-expansion models, LSEs can use detailed analysis with production cost models to develop cost/value adjustment factors that improve the representation of different resource options in capacity-expansion models.

- *Most studies account for integration costs related to solar, but few LSEs have conducted detailed studies to estimate those costs.* Most planning studies accounted for the potential increase in operational integration costs with solar, and many can account for impacts related to hour-to-hour changes in solar production/operational constraints when evaluating portfolios with solar in production cost models. LSEs have conducted few actual studies of operational integration costs or impacts, however, resulting in many LSEs relying on rules of thumb, results from studies in other regions, or results from wind integration studies. LSEs could improve the representation of the benefits of solar in their portfolios by conducting refined integration studies specific to their systems or to systems in their region. Any integration cost estimates from these studies would be most useful if they fill gaps or address limitations in what is already included in the production cost models or capacity-expansion models used by the LSE.

- *Transmission and distribution benefits, or costs, related to solar are not often accounted for in LSE studies.* The difference in avoided costs between utility-scale solar and distributed PV are not well known, but as more studies provide insight into these differences, LSEs should consider incorporating that information into their planning studies.

- *Few LSE planning studies can reflect the full range of potential benefits from the addition of thermal storage and/or natural gas augmentation to CSP plants.* Few studies appeared to include detailed analysis of the potential for CSP with thermal storage to shift solar production to times of most value for a particular scenario, provide ancillary services, or reduce the impact of operational constraints from conventional generation. To capture the full benefits, representation of the dispatchability of CSP with thermal storage (and/or natural gas augmentation) could be improved in both capacity-expansion and production cost models. If it is not practical to model directly the dispatchability of these resources in the LSEs' planning models, then estimates of the benefits of dispatchability, based on separate side analyses, could adjust the costs/benefits of these resources in the planning models. Identifying the full range of benefits may be increasingly important at higher penetrations of variable renewable energy, particularly solar energy.

- *The level of detail provided in RFPs is not always sufficient for bidders to identify what technology or configurations will be most valuable to LSEs.* While solar developers and manufactures have some ability to tailor solar technologies or configurations to the needs of an individual LSE, the tradeoffs between higher bid cost and higher economic value are not clear in many LSE procurement documents. This lack of clearly defined metrics and weightings in RFPs may hamper efforts to ensure the most economically attractive options are bid into an RFP. It could also lead to respondents providing multiple bids with different technology variations that must be evaluated by the LSE. Increased clarity in the methods used by LSEs to evaluate the net cost of bids may increase the attractiveness of particular RFP responses.

Finally, although this review focused on the valuation of solar in planning and procurement, many of the LSEs are considering other renewable technologies, particularly wind. Many of the lessons learned from this analysis and the recommendations apply to the evaluation of other renewable energy options beyond solar.

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Appendix A. Summary of LSE planning and procurement practices

Northwest Power Conservation Council:

The Northwest Power Conservation Council (NPCC) develops a resource strategy to guide the planning decisions of the Bonneville Power Administration and utilities in the Northwest, a region characterized by significant amounts of energy-constrained hydro resources. The strategy outlines resource types and priorities rather than specifying a particular timing and quantity of power plants to procure. NPCC develops this resource strategy using a regional capacity-expansion model developed by the NPCC. The model develops thousands of portfolios (2,000–5,000 individual portfolios) that are then each subjected to 750 alternative futures (between 2010–2030) to determine the present value of the total revenue requirement in each of those futures. Each portfolio is characterized by its expected PVRR (the portfolio cost) and the average of the PVRR across the top 10% of most costly futures (the portfolio risk). NPCC then appears to identify the portfolio strategy that is the lowest cost subject to not having higher risk than any of the other portfolios, in what the NPCC calls the "risk-constrained, least-cost plan." This plan represents the least-cost portfolio strategy that can be taken today while limiting exposure to uncertainty in many of the important parameters that impact costs including fuel costs, carbon risk, demand growth, and hydro flows.

The capacity-expansion model does not appear to have peak-hour or annual energy constraints to ensure reliability. Instead, those portfolios that build too little new resources (including energy efficiency or new power plants) are exposed to high market prices in some futures, whereas portfolios that build too many new resources end up being too costly. In this way the overall risk-constrained, least-cost portfolio ends up having significant amounts of new capacity (or energy efficiency) to prevent exposure to bad outcomes relative to what would be built to just satisfy a minimum resource adequacy requirement.

Among other resource options, the NPCC characterizes utility-scale PV (20-MW plants) and CSP with 6–8 hours of thermal storage. Hourly generation profiles from select sites in the Northwest (Ely, NV for CSP) are developed from the NREL System Advisor Model (SAM). The dispatch portion of the capacity-expansion model only uses quarterly average values for both on-peak and off-peak periods to determine production costs for a given portfolio (i.e., the dispatch is characterized by 8 periods per year). The on-peak period is defined as non-Sundays between 7 am and 10 pm in each quarter. NPCC further adds an integration cost to utility-scale PV that is the same as the integration cost added for wind ($8.85/MWh rising to $10.9/MWh by 2024). Although it does not appear that firm capacity is used to develop feasible portfolios in the NPCC capacity-expansion model, the NPCC does indicate that CSP with thermal storage would "impart some firm capacity." Utility-scale PV would only be considered as an energy resource (like wind) due to the poor coincidence of PV and Pacific Northwest loads. No additional detailed modeling is used to evaluate the performance of any of the portfolios. In addition, the NPCC is not responsible for procuring resources identified in the preferred strategy.

Category	Value
Solar technologies considered	Utility-scale PV CSP with 6-8 hours thermal storage
Solar capacity credit	Not available
Solar integration cost for resource selection	$8.85/MWh rising to $10.24/MWh by 2024 for PV
Solar integration cost for portfolio evaluation	Same
Resolution of production cost model	Two periods per quarter

PacifiCorp:

Based on a review of the 2011 IRP and the 2010 Solar RFP, PacifiCorp has one of the more thorough but complex methods for estimating the value and cost of future portfolios of resources and ranking bids received during renewable procurement.

In evaluating future portfolios PacifiCorp begins by using a capacity-expansion model (System Optimizer, Ventyx) to create and select portfolios with the lowest PVRR for a set of assumptions about the future (between 2011–2030). The revenue requirement includes transmission cost, the variable cost of dispatching resources and making market purchases, the fixed cost of maintaining existing units, and the investment cost of any new resources. Each feasible portfolio must have sufficient capacity to meet a minimum planning reserve margin (including the contribution from renewables). The dispatch cost within the model is based on 12 months each represented by a single week. They select optimal portfolios for a given set of assumptions across many different scenarios (more than 60 scenarios). The solar resources included in the analysis include utility-scale PV systems (5-MW plants), distributed rooftop PV, and CSP with and without thermal storage. The CSP without thermal storage has natural gas augmentation with a high heat rate (11,750 Btu/kWh). It is not clear how the reliability contribution of solar is estimated, but the 'Z-method' approximation of the effective load-carrying capability (ELCC) is used for wind (Dragoon and Dvortsov 2006). This approximation does not appear to account for changes in capacity credit as a function of penetration. PacifiCorp also considers many grid-level storage options: batteries, pumped hydro storage, and compressed air energy storage.

These optimal portfolios for a given set of assumptions are then subjected to a Monte-Carlo analysis using a production cost model (PROSYM module within Planning and Risk, Ventyx) to estimate the cost if the portfolio were fixed but the future turned out to be different than assumed when developing the portfolio. The dispatch in the production cost model can account for operational constraints for conventional generation including minimum up and down times, start-up costs, ramp rates, etc. It appears that the data used in the production cost model are based on one week per month for each month of the year. The different portfolios are then compared across several metrics related to cost (average cost), risk (upper tail costs), and reliability (ability to meet demand). The two best-performing portfolios are then evaluated again in 10 different scenarios of carbon cost and natural gas cost (carbon and natural gas are seen as the two largest sources of uncertainty). The final portfolio is then selected from these two.

When PacifiCorp seeks to procure resources that match its preferred portfolio it also uses a thorough evaluation method that builds on its IRP. Bids are ranked based on a net present value metric that is the difference between the value of capacity and energy from the bid and the offsetting costs of the bid. The greater the net value, the higher the bid is ranked. The value of the resources is estimated by comparing the production cost with and without the bid resource included in the most recent IRP preferred portfolio. This production cost savings (the energy value) is then adjusted by any incremental capacity savings and any integration cost from the most recent IRP (no integration cost is specified for solar, but there is a cost for wind). It is not clear how the avoided capacity is estimated for the solar resource.

Category	Value
Solar technologies considered	Utility-scale PV Rooftop distributed PV CSP with natural gas fired boiler without thermal storage CSP with thermal storage
Solar capacity credit	Not available
Solar integration cost for resource selection	Not specified for solar, one is used for wind
Solar integration cost for portfolio evaluation	Same
Resolution of production cost model	Hourly for one week each month, includes operational constraints

Public Service New Mexico:

PNM similarly uses a thorough method to estimate the value and cost of future portfolios and to rank bids during renewable procurement.

PNM first uses a capacity-expansion model (Strategist, Ventyx) to create and select portfolios of resources with the lowest present value of the portfolio cost for a given set of assumptions about the future (between 2011–2030). The portfolio cost includes transmission cost, the variable cost of dispatching resources, the fixed cost of maintaining existing units, and the investment cost of any new resources. In contrast to PacifiCorp, the portfolios do not include any off-system sales or imports. Each feasible portfolio must have sufficient capacity to meet a minimum planning reserve margin (including the contribution from renewables). The dispatch cost within the model is based on 12 months each represented by a single week. PNM selects optimal portfolios for a given set of assumptions across many different scenarios (26 scenarios). The solar resources included in the analysis include utility-scale PV systems (40-MW plants), small distributed PV with a lead-acid battery (1-MW plant size), and CSP with three hours of thermal storage and without thermal storage. Forecasts of customer-sited PV are used to reduce the future peak load forecast. The capacity credit for PV and CSP without thermal storage is assumed to be 55% and does not change as a function of penetration. The capacity credit is estimated as the net dependable summer capacity coincident with PNM’s system peak load. The capacity credit of the distributed PV with a lead-acid battery is assumed to be 100%. This option was not included in further modeling after a test case conducted using Strategist found a micro-turbine DG plant to be more cost effective than PV with a lead-acid battery.

These optimal portfolios for a given set of assumptions are then subjected to a Monte-Carlo analysis using only the production cost component of the same Strategist model (PROVIEW) to estimate the cost if the portfolio were fixed but the future turned out to be different than assumed when developing the portfolio. The dispatch in this stage does allow for off-system sales or imports (based on wholesale electricity prices generated from sampling historical price distributions). The different portfolios are then compared based on average cost and risk (upper tail cost). PNM selected the least-cost portfolio as its preferred portfolio, noting that in many cases differences in expected costs across portfolio options were greater than differences in the risk across several important uncertainties.

When PNM seeks to procure resources that match its preferred portfolio it also uses an evaluation method that builds on its IRP. Bids are ranked based on a net PVRR metric that is the difference between the costs of the bid and the avoided production costs from the resource. The lower the net revenue requirement, the higher the bid is ranked. The avoided production cost of the resource is estimated by comparing the production cost with and without the resource included in the most recent IRP preferred portfolio. It is not clear whether avoided incremental capacity or integration costs (to account for factors that would not be accounted for in the production cost model) are considered in the ranking.

Category	Value
Solar technologies considered	Utility-scale PV Distributed PV with a lead-acid battery CSP without thermal storage CSP with 3 hours of thermal storage
Solar capacity credit	55% for utility-scale PV and CSP without thermal storage 100% for small PV with a lead-acid battery
Solar integration cost for resource selection	Not available
Solar integration cost for portfolio evaluation	Not available
Resolution of production cost model	Hourly for one week each month, includes operational constraints

Tri-State Generation & Transmission:

Similar to PNM, Tri-State uses a capacity-expansion model (System Optimizer, Ventyx) to create a portfolio of resources with the lowest present value of the portfolio cost for a given set of assumptions about the future (between 2010–2029). Similar to PNM, they select optimal portfolios for a given set of assumptions across many different scenarios (24 scenarios). Using the same scenario-specific assumptions used to create a portfolio, the variable cost of each portfolio is calculated using a production cost model (Planning and Risk, Ventyx) with a higher degree of detail than used in the capacity-expansion model. The production cost model uses hourly data over at least a full year. In some scenarios the production cost model does allow off-system sales or the purchases of power at wholesale electricity prices. The average wholesale electricity price was a scenario-specific assumption. The total PVRR of each portfolio is calculated using the capital cost and fixed O&M cost for existing and new resources from System Optimizer, variable costs from the production cost model, and scenario-specific transmission costs developed by Tri-State's transmission planning group. Tri-State seeks to maintain a 15% planning reserve margin.

The solar resources included in the analysis include PV systems (10-MW plants with no separate consideration of unique benefits of distributed PV) and CSP with three hours of thermal storage.

Tri-State indicates that they use a probabilistic LOLP study to determine the capacity credit of different technologies. For PV, however, they indicate that they rely on the expected capacity of PV during Tri-State's peak load hour. The resulting value is 20% to 57% of the PV nameplate capacity (they do not specify why there is a range of values), but Tri-State does not indicate what value within this range they use, if any, in the capacity-expansion model. They do not mention any assumption for the capacity credit of CSP with thermal storage nor do they mention any changes to the capacity credit of solar with penetration. Furthermore, comparison of a scenario with new CCGTs and wind to a scenario with new CCGTs and a combination of wind and CSP with 3 hours of thermal storage indicates that inclusion of solar in the portfolio did not displace the need for capacity from the CCGTs. In both cases nearly 1,200 MW of CCGT capacity is added even though the case with 150 MW of CSP with thermal storage should require less conventional capacity to meet the planning reserve margin. The cause may be the lumpiness of gas-fired plants considered by the capacity-expansion model: the minimum size of gas plants was 290 MW for a 1X1 CCGT. The capital cost of the 290 MW CCGT was 35% more expensive than a larger 588 MW 2X1 CCGT option. The lumpiness potentially prevents the capacity-expansion model from recognizing the capacity contribution of 150 MW of CSP with 3 hours of thermal storage.

Tri-State applies an integration cost to all intermittent resources: the same integration cost is assumed for wind, PV, and CSP with thermal storage in the capacity-expansion model and the production cost model results. In most scenarios the assumed integration cost is $5/MWh. In scenarios with higher proportions of renewables (due to assumed greater RPS levels or carbon policy) the integration cost increases to $7.5/MWh, $8/MWh, or $10/MWh.

Tri-State does not evaluate the sensitivity of the PVRR of each portfolio to changes in assumptions about the future. Tri-State did not select a specific preferred portfolio; instead they used the results of the scenarios to inform the resource procurement plan.

Category	**Value**
Solar technologies considered	Utility-scale PV CSP with 3 hours of thermal storage
Solar capacity credit	Indicate a range of 20%-57% for PV but do not specify the value used
Solar integration cost for resource selection	$5-$10/MWh for PV and CSP with 3 hours of thermal storage depending on the scenario-specific assumptions
Solar integration cost for portfolio evaluation	Same
Resolution of production cost model	Hourly, includes operational constraints

Duke Energy Carolinas:

Duke Energy Carolinas includes PV as a potential resource in its IRP (utility-scale PV; it does not appear to separately consider any unique benefits of distributed PV). Duke first applies a basic screening on technology options to determine which should be characterized for inclusion in a commercial capacity-expansion model. The basic screening is done using screening curves (similar to the manner described by Stoft 2002). This approach is useful for dispatchable resources like CTs, CCGTs, coal, nuclear, and biomass renewable resources. Duke Energy, however, also applies the same approach to wind and solar, though it limits the screening curve to the range of plausible capacity factors for each technology. Implicitly, the use of screening curves assumes the resources will be perfectly dispatchable within the available capacity factor of wind and solar. If the screening curve shows the wind and solar is less attractive than other generating options even using this generous assumption then it is clearly not going to be attractive even if the realistic coincidence of generation and load is accounted for. On the other hand, if this screening curve approach does show a lower cost for the wind or solar the result is still uncertain since the real correlation between generation and load is not contained within the screening curve. In this case alternative comparison methods would need to be used such as the net cost approach discussed in the main text. The screening curve approach with wind and solar is therefore subject to the critique from Joskow (2011) that suggests that comparisons on levelized cost are not enough to determine relative economic attractiveness of various options.

After screening technologies, Duke characterizes the selected resource options for use in the System Optimizer (Ventyx) capacity-expansion model. Duke creates a portfolio of resources that satisfies the assumed 17% planning reserve margin with the lowest PVRR for a set of assumptions about the future. The only solar technology that is characterized in the capacity-expansion model is PV. PV is assumed to contribute 50% of its nameplate capacity toward meeting peak load. Duke then generates alternative portfolios by altering the assumptions used in the capacity-expansion model. The sensitivities include changes in fuel prices, load levels, and construction costs. A subset of the portfolios are then chosen for more detailed analysis in a production cost model (the name of the model is not specified nor are many other details about the model). Duke highlights concerns about renewables integration but does not specify an integration cost for PV (or wind) for use in the capacity-expansion or production cost model.

Category	**Value**
Solar technologies considered	Utility-scale PV
Solar capacity credit	50% for PV
Solar integration cost for resource selection	Not available
Solar integration cost for portfolio evaluation	Not available
Resolution of production cost model	Not available

Tucson Electric Power:

Similar to PNM, Tri-State, and Duke, TEP uses a capacity-expansion model (Capacity Expansion [a precursor to System Optimizer], Ventyx) to create a baseline portfolio with reference assumptions and several other portfolios under conditions where assumptions about the future differ from the reference case. For TEP the key assumptions include natural gas prices, wholesale power prices, and load growth. TEP, however, does not present any results or analysis based on these sensitivity scenarios. Instead the baseline portfolio is compared to a small set of manually created alternative portfolios. In the 2012 IRP TEP was particularly focused on the impact of potential coal plant retirement or divestitures. The capacity-expansion model maintains all existing coal plant investments in the baseline portfolio. The alternative, manually created, cases replace the capacity from a coal plant investment with an equivalent amount of capacity from a new combined-cycle gas turbine. Each portfolio is designed to have an equivalent 15%

planning reserve margin in all years, including the dependable capacity contribution of solar and wind. No additional assessment of risk or sensitivity to changes in assumptions about the future are presented in the IRP.

The solar resources that are considered as candidate resources to be included in the portfolios included fixed and single-axis tracking PV (both 20-MW plants) and CSP with and without thermal storage. A small amount of distributed PV is included to comply with the DG component of the Arizona renewable energy standard; no additional benefits of distributed PV appear to be identified in the planning study. To better understand the selection of resources in the capacity-expansion model, TEP estimated the relative attractiveness of different resource options. TEP estimated the delivered cost of each resource in $/MWh terms with the cost for wind and solar adjusted by an integration cost and a capacity cost adder. The integration cost was $4/MWh for fixed and single-axis tracking PV, $2/MWh for CSP without thermal storage, and $0/MWh for CSP with thermal storage. The solar integration costs were based on the previous APS wind study, a PSCo solar integration study, and a Navigant PV integration study for NV Energy. TEP assumes the capacity credit of fixed PV is 33% of the nameplate capacity, single-axis tracking PV is 51%, CSP without thermal storage is 70%, and CSP with thermal storage is 87%. The capacity credits are assumed based on expected generation coincident with peak demand. The resulting capacity cost adder is about $47/MWh for fixed-axis PV, $23/MWh for single-axis PV, $12/MWh for CSP without thermal storage, and $4/MWh for CSP with thermal storage (and in the range of $30–$35/MWh for wind). It is not clear how TEP estimates the capacity cost adder.

The net PVRR for the baseline and three alternative portfolios is then estimated based on the capital expenditure and the production costs from a production cost model (Planning & Risk, Ventyx). It is not clear what time resolution the model uses in this case. It appears that the same integration costs used in the capacity-expansion model are applied in the production cost model.

Category	**Value**
Solar technologies considered	Fixed and single-axis PV CSP with and without thermal storage
Solar capacity credit	33% for fixed PV 51% for single-axis tracking PV 70% for CSP without thermal storage 87% for CSP with thermal storage
Solar integration cost for resource selection	$4/MWh for fixed and single-axis tracking PV $2/MWh for CSP without thermal storage $0/MWh for CSP with thermal storage
Solar integration cost for portfolio evaluation	Same
Resolution of production cost model	Not available

El Paso Electric:

El Paso Electric also uses Strategist to create portfolios of resources to satisfy its needs for future years (2012–2031). El Paso first uses Strategist to generate an optimal expansion plan based on a baseline set of assumptions. El Paso then generates several additional portfolios based on sensitivity scenarios that change one uncertain assumption at a time (high natural gas price, low natural gas price, higher carbon dioxide prices, lower load forecast, higher load forecast, later retirement years for existing plants). PV is the only solar technology considered in the portfolios (20-MW thin film plants, no separate distinction of the benefits of distributed PV). It is not clear what capacity credit is assigned to PV or how it is estimated. El Paso assumes a constant 15% planning reserve margin. It is also not clear what time resolution is used in the production cost modeling. El Paso indicates that they use typical energy profiles “particularly during EPE’s [El Paso Electric’s] summer peak months, May through September, to capture the resources’ intermittency.” El Paso does not mention any adjustments for integration costs for PV.

El Paso selected the portfolio with the least cost in a case with assumed later retirement dates for existing units. El Paso explains that without the later retirement dates El Paso is concerned that too many new units would need to be built at the same time. Later retirement of existing units allows the construction of new generation capacity to be staggered.

El Paso had a recent RFP for peaking resources that allowed renewable resources to participate. El Paso made it clear, however, that any renewable resource would need to be able to be dispatched by El Paso Electric on an hourly basis. Furthermore, renewable projects must also specify the project's minimum guaranteed on-peak generation between 11 am and 4 pm from May through September in order to determine the capacity value. The PPA will contain penalty provisions for not meeting this minimum. As part of the proposal the renewable bidders are required to provide a typical day hourly profile for each month. These stringent conditions may be suitable for CSP with thermal storage or with natural gas augmentation but would likely prevent the participation of CSP without thermal storage or natural gas augmentation and PV without electrical storage. Interestingly, the RFP resulted in a winning bid from a solar project that did not meet the firm capacity requirement along with El Paso’s self-bid of four LMS100 CTs.

The methodology used to carry out the economic evaluation of bids is not clear in the RFPs, though El Paso indicates that they consider a resource’s relative cost effectiveness in meeting their requirements. Factors included in establishing cost effectiveness include the costs of the resource (capacity costs, energy/fuel costs, fixed and variable O&M costs, start-up costs) and the benefits of the resource (production cost impacts, net capacity contribution).

Category	**Value**
Solar technologies considered	PV
Solar capacity credit	Not available
Solar integration cost for resource selection	Not available
Solar integration cost for portfolio evaluation	Not available
Resolution of production cost model	Not available

Public Service of Colorado:

Like PNM and El Paso, PSCo utilizes the Strategist capacity-expansion model to create a portfolio of resources. Unlike PNM and El Paso, however, PSCo only uses the model to build one least-cost baseline portfolio. The baseline portfolio is built using “starting point” assumptions regarding future fuel costs, investment costs, etc., rather than building many portfolios using Strategist for various scenarios of potential future trajectories. The solar resources included in the portfolio options include PV (25 MW, no separate consideration of the benefits of distributed PV) and CSP with thermal storage. Grid-level batteries (25 MW) are also included as a generic dispatchable resource that can be chosen by the capacity-expansion model. The production cost component uses an hourly generation profile over a week for each month of the year for single-axis tracking PV and CSP with thermal storage. A static hourly generation profile was used to model CSP with thermal storage rather than allowing the thermal storage to be dispatched according to system needs. An integration cost is added to the cost of PV. The most recent publicly available study, from 2009, estimates the integration cost based on the cost related to day-ahead forecast errors ($5.15/MWh). The capacity credit of PV is based on its most recent ELCC study, which estimates a 55% capacity credit for PV. The capacity credit of CSP with thermal storage is assumed to be 100%.

After using the model to build the baseline portfolio, PSCo then manually created eight different renewable alternative plans to compare to the least-cost baseline portfolio. In some cases, the Colorado Public Utilities Commission requires PSCo to adjust the composition of the alternative plans to examine resources that are of interest but may not have been identified as part of the least-cost baseline (e.g., high renewables portfolios). PV is added to a portfolio that already includes much more wind while CSP with thermal storage is added to portfolios that already include PV and wind. Some of the manually created portfolios with wind and PV also included batteries. The addition of the batteries always increased the PVRR relative to the same portfolio without the batteries. The overall reliability of the alternative portfolio is maintained at a constant level by removing CTs from the portfolio based on the capacity credit of the renewables (the CTs are actually lumpy, so CTs end up only being removed when the total amount of renewables in the portfolio is large; any excess capacity is credited at the capital cost of CT).

PSCo then tests the baseline portfolio and the eight alternative portfolios to six sensitivity scenarios where the resources included in the portfolio remain fixed. Two additional sensitivity cases, a high and low sales case, were also examined but the resources in each portfolio were changed to maintain the same level of reliability compared to the median load base case. The same integration cost is added to the production cost results for PV based on the 2009 solar integration study. Only CTs were added or removed from the portfolios in response to changes in projected sales. After reviewing the performance of the different portfolios (using the PROVIEW production cost module within Strategist), PSCo selected the baseline portfolio as the preferred portfolio.

When procuring resources, PSCo places all resource bids that pass an initial economic screening into the Strategist model to develop a least-cost portfolio of bids that minimize the net PVRRs over the planning period (2011–2050). Additional portfolios that represent a range of renewable technologies, PPA lengths, ownership arrangements, etc. are also advanced for further analysis. These portfolios are then subjected to different scenarios regarding natural gas fuel price, carbon price, and construction escalation rates. The preferred portfolio is selected by the utility after reviewing these results. For solar resources the generation profile is based on one of four regional profiles (with or without tracking) and then scaled to the bidder's capacity and energy generation. The solar capacity credit of PV is based on the most recent ELCC study, which varies by region, and whether or not the PV has tracking. The capacity credit does not change as a function of the amount of solar included in the portfolio.

Category	Value
Solar technologies considered	Utility-scale PV CSP with thermal storage
Solar capacity credit	55% for PV 100% for CSP with thermal storage
Solar integration cost for resource selection	$5.15/MWh for PV $0 for CSP with thermal storage
Solar integration cost for portfolio evaluation	Same
Resolution of production cost model	Hourly for one week each month, includes operational constraints

California IOUs Process - LTPP and LCBF:

CPUC uses the Long-Term Procurement Plan (LTPP) process as an umbrella proceeding to comprehensively evaluate and refine various procurement practices and policies related to several other programs including the RPS, energy-efficiency, demand response, resource adequacy, and transmission. When necessary, recommended changes to practices or strategies identified in the LTPP can be implemented via the appropriate proceeding for each particular program. In addition, renewable resource portfolios developed in the LTPP process are used to identify transmission needs in the CAISO transmission planning process. Renewables procurement authorization on a year-to-year basis currently occurs through a different process at the CPUC, but the LTPP is intended eventually to be the place where long-term procurement planning occurs for renewable resources to meet the 33% RPS. As such, while renewables are an integral part of the LTPP process, the ranking of different resource portfolios currently has a limited and somewhat indirect impact on renewable procurement decisions.

In the 2010 LTPP process, the IOUs worked with the CPUC, the California Independent System Operator, and stakeholders to develop and evaluate future resource portfolios that included significant amounts of renewable energy ("the CA IOU process").[30] In contrast to the approaches at other LSEs described in this Appendix that relied on commercial capacity-expansion models to develop resource portfolios given different assumptions, the CA IOU process selected four primary portfolios that were compared across several metrics including the PVRR. Resource selection in the four portfolios was limited to the renewable net short and CTs needed to maintain system reliability. The renewables net short is the difference between the amount of renewables required to meet the 33% by 2020 RPS and the current level of renewables already in place or contracted (renewable resources with signed PPAs, PPAs under review by the Commission, or resources with major permits already granted). Demand-side measures, including energy efficiency and demand response programs, were assumed to be met based on California targets and goals. The selection of the renewables to meet the net short varied across

[30] The full set of inter-relationships between different proceedings within the CPUC and various other state and federal agencies involved with the California IOU planning and procurement process is much more involved than described in this limited review focused on solar. For a more detailed overview of the CA process see the supporting documents reviewed in this report and a recent overview prepared for the Regulatory Assistance Project (Burgess et al. 2012).

the four portfolios to create bookends that show the impact of different policy objectives (trajectory, cost constrained, environmental impact constrained, and time constrained).

The renewables for the cost-constrained scenario were ranked by the resource-specific economic ranking cost (similar to the RETI/WREZ approach). The potential renewable resources included wind, PV, CSP without thermal storage, geothermal, small hydro, biomass, and biogas. It appears that CSP with thermal storage was characterized, but was not included as an option for the resource ranking or inclusion in the four primary portfolios. The ranking cost is the difference between the resource cost (PPA price, interconnection and transmission delivery cost, and integration cost) and the resource value (capacity value, energy value, avoided T&D costs). The integration cost was assumed to be $7.5/MWh for all wind, PV, and CSP. The capacity value is based on the capacity credit of the resource and the avoided cost of a new CT. The capacity credit in the ranking cost calculation varied by solar technology and location. For PV the capacity credit of utility-scale fixed PV was 51% and utility-scale tracking PV was 65%, but it was assumed to be 0% for small and distributed PV. The capacity credit of CSP without thermal storage ranged from 71% to 87% depending on location, and the capacity credit of CSP with thermal storage was 100%. The energy value is based on the time-varying generation profile and time-varying wholesale energy prices in California over a year. The avoided T&D cost benefit is only applied to distributed resources, including distributed PV, and represents the estimated deferral of T&D network upgrades. The avoided T&D benefit ranged from $4.28/MWh to $26.26/MWh with the most common benefit being $4.84/MWh.

Once the four portfolios were created, sufficient CTs were added to the portfolios in order to meet a planning reserve margin above the expected load in 2020. The capacity credit for each portfolio was estimated based on the California net qualifying capacity (NQC) methodology, which looks at the generation during the peak load period (1–6 pm April–October, 4–9 pm November–March) that is exceeded 70% of the time. The NQC is not equivalent to an ELCC and does not change with penetration.[31] Detailed production cost modeling (PLEXOS, Energy Exemplar) was then used, in part, to estimate the total revenue requirement for each of the portfolios. The production cost modeling included a detailed hourly simulation over a full year of the entire WECC system and included increased operating reserve requirements for each renewable portfolio. Additional CTs were added in cases where in some hours the production cost model found that the resources would not be able to meet all load and operating reserve requirements. The cost of these CTs, CTs added for meeting the planning reserve margin, renewables, existing generation O&M, variable fuel and emissions, and T&D were all included in the estimate of the PVRR. The distribution costs in the case with significant distributed PV was lower than the other cases. Since the production cost model is run for each portfolio, any change with the energy value of different renewables is also captured in the modeling. Further, even though the capacity credit assigned to renewables does not change with penetration, any actual decrease in the true capacity credit would be resolved through the addition of CTs to solve violations in the detailed production cost model runs. No preferred portfolio was selected from the 2010 LTPP process, though the cost-constrained portfolio was found to have the lowest cost. Also in contrast to other LSE studies in the sample, no detailed scenario analysis or stochastic

[31] Changes to the NQC methodology to reflect changes in capacity credit with increasing penetration would need to occur through the Resource Adequacy program.

analysis was used to evaluate changes in the revenue requirement if key uncertainties, including natural gas fuel cost or carbon costs, changed from the assumed levels.

When evaluating bids for procurement of renewable resources, the California IOUs rank bids based on a “least-cost, best-fit” methodology (LCBF). The methodology ranks bids based on the costs and benefits of each individual bid. For Pacific Gas and Electric (PG&E) this results in a market value estimate that is the benefits less the costs. For SCE this results in a net levelized cost of renewables premium that is the costs less the benefits. In both cases the benefits include the capacity benefit and energy benefit. The costs include the bid in contract cost, transmission costs, and an integration cost adder. Based on guidance from the CPUC, the integration cost adder is currently assumed to be zero (even though the ranking of resource options in the creation of candidate portfolios described above assumed an integration cost of $7.5/MWh). The capacity benefit is based on the current estimate of the capacity credit (based on the NQC 70% exceedance methodology outlined in the CPUC resource adequacy program) and estimates of the cost of capacity resources. The energy benefit in the case of SCE is based on the product of the bidding resource's generation profile and hourly wholesale power prices from a production cost model run (PROSYM, Ventyx). The base resource profile for the production cost model run is a recent portfolio from the California long-term planning process. PG&E similarly calculates the energy value based on the bidding resource's generation profile and wholesale market prices, but PG&E uses forward electricity prices rather than prices modeled in a production cost model.

Category	Value
Solar technologies considered	Fixed and tracking PV CSP without thermal storage
Solar capacity credit	51% for utility-scale fixed PV 65% for utility-scale tracking PV 0% for small scale and distributed PV 71%-87% for CSP without thermal storage 100% for CSP with thermal storage
Solar integration cost for resource selection	$7.5/MWh for PV and CSP without thermal storage
Solar integration cost for portfolio evaluation	Implicitly calculated as increased operating reserve requirement and additional cost of any new CTs required to meet operating reserves
Resolution of production cost model	Hourly over a year, includes operational constraints

Los Angeles Department of Water and Power:

Similar to the methodology used by the CA IOUs in the long-term planning process, LADWP adds sufficient renewable resources to its portfolio to meet the 33% RPS by 2020. The renewable resources are selected using a ranking cost for all renewable options. The ranking cost is meant to “measure different renewable resources on a comparable basis” and is calculated in a manner similar to what is used in the CA IOUs process (and similar to the method used in RETI/WREZ). The renewable resources considered include wind, geothermal, biomass, and PV (utility scale or distributed) and were largely based on resources identified within the WREZ process. The ranking cost is the renewable generation cost plus grid integration cost (including transmission and balancing costs) less the capacity value and energy value. The capacity value is based on the capacity credit (called the dependable capacity) and the fixed investment cost of a CT. The capacity credit for PV appears to be set at 27%: there is no suggestion that the capacity credit is based on an ELCC-like method nor that it would change with penetration of solar. The energy value is based on the renewable resource generation profile and time-varying wholesale market prices, though it is not clear what source was used to generate the prices or the generation profiles of the renewable generators.

Aside from the renewable portion of its portfolio, LADWP manually created a small number of different portfolios to test the impact of different decisions regarding divesture of thermal power plants (primarily coal). The makeup of the portfolios was determined based on expert judgment and a constraint that each portfolio must have sufficient dependable capacity (including the contribution of renewables) to meet the projected generation capacity requirement (load plus operating reserves) in each year between 2013 and 2020. A mix of energy efficiency, demand response, and combined cycle natural gas plants was added to each scenario with short-term purchases filling in any remaining need. It is not clear what, if any, cost was assigned to the short-term purchases. The total PVRR for the different portfolios was calculated using a production cost model (Planning and Risk, Ventyx) for three sets of assumptions: a high, reference, and low natural gas price. The production cost model was also used to calculate the CO_2 emissions for each portfolio. A portfolio that had a slightly higher cost but lower CO_2 emissions than other options was selected as the preferred portfolio. The production cost model is chronological, accounts for operational constraints on conventional generation, and has an hourly time resolution, but it is not clear if they run the analysis over 8,760 hours per year or a typical week each month. The model also appears to include some representation of the transmission network, which may lead to additional value in the form of reduced line losses for distributed PV that is sited in the transmission zones that represent major load centers (as long as the production cost model accounts for line losses).

LADWP, like many publicly owned utilities in Southern California, procures renewable energy at least in part through SCPPA. SCPPA's most recent renewables RFP does not provide many details regarding the economic evaluation of proposals. One potentially telling feature, however, is that SCPPA applies a maximum levelized cost cap that differs by technology as part of the initial proposal screening. Wind bids must be less than $60/MWh, baseload technologies like geothermal must bid less than $100/MWh, and solar technologies with or without storage must bid less than $110/MWh. SCPPA requires a bidder to detail its energy availability by describing maximum and minimum monthly capacity factors, seasonal shapes, and dispatchability. SCPPA also requires that all capacity rights associated with the energy are provided to SCPPA. Aside from those requirements SCPPA does not describe how they economically evaluate different proposals or determine which bids are most attractive.

Category	**Value**
Solar technologies considered	Utility-scale and distributed PV
Solar capacity credit	27%
Solar integration cost for resource selection	Not available
Solar integration cost for portfolio evaluation	Not available
Resolution of production cost model	Hourly with operational constraints

Arizona Public Service:[32]

Similar to the California process and LADWP's approach, APS does not use a capacity-expansion model to generate portfolios of resources to meet its needs: portfolios are manually designed. Unlike the California approaches, APS does not use a ranking cost method to determine the relative ranking of renewable resources to include in its candidate portfolio. Instead APS developed four different portfolio options largely based on engineering judgment, stakeholder input, and an assessment of options for maintaining compliance with regulations (including energy efficiency and renewable targets).

APS does include a discussion of the relative "delivered cost" of different resource options that guides the design of the portfolios. The levelized delivered cost of different resources includes the generation cost, emissions cost, and transmission and losses cost. In addition, for renewable resources, the cost includes an integration and firm-up cost. The integration cost for wind ($3.25/MWh) was derived from an APS-specific integration study. The integration cost for PV ($2.5/MWh) was based on assumptions from the Western Renewable Energy Zone Generation and Transmission Model. The firm-up cost, on the other hand, is much larger (>$60/MWh for wind, ~$25/MWh for solar). The firm-up costs are based on the capacity-equivalent capacity adder approach described in this report in Text Box 2. For example, APS assumes a 70% capacity credit for single-axis tracking PV generation such that adding 100 MW of PV requires an additional 30 MW of firming capacity in order for the PV and firming capacity to have a combined load-carrying capability of 100 MW. The firm-up costs are then estimated as the fixed costs associated with the firming capacity (a 30-MW CT) divided by the energy production of the solar project.

In designing each of the four portfolios, the total summer peak dependable capacity is kept constant across all portfolios and is equivalent to the sum of the peak APS demand and reserve requirements. The solar technologies included in the 2012 plan are distributed fixed PV, utility-scale tracking PV, and the existing contract for a CSP plant with six hours of thermal storage (the Solana plant). Other solar technologies were characterized but are not included in any of the portfolios. The line loss reduction benefits of distributed PV are included in the estimate of the costs of portfolios with distributed PV (though APS does not separately summarize these benefits). The base capacity credit of the different solar options is 50% for fixed PV, 70% for single-axis tracking PV and CSP without thermal storage, and 100% for CSP with thermal storage (6 hours) or for solar thermal/gas hybrid plants. Site-specific estimates of capacity credits for single-axis tracking are in the range of 65%–77%, which differs from the generic (non-site specific) estimate of 70%. An ELCC method is used to estimate the capacity credit of solar technologies for each different portfolio of resources (based on the methodology outlined by R.W. Beck 2009). The capacity credit of PV does therefore depend on PV penetration levels in each of the different portfolios (Figure A-1).

[32] In addition to the detail provided in the 2012 APS IRP, APS resource planning staff provided supplementary information during the review process that is reflected in this summary.

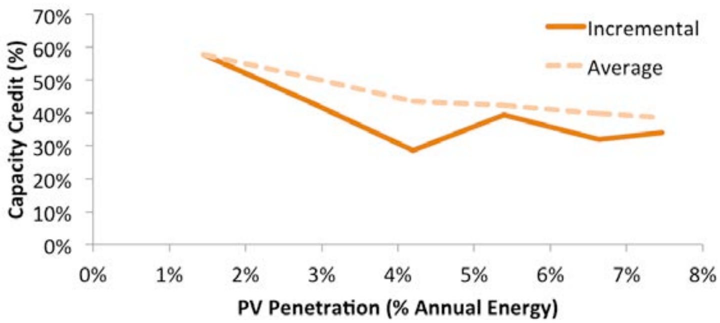

Figure A-1. Estimated PV capacity credit with penetration level for APS Base Plan

The total PVRR for each portfolio is estimated (2012–2027) including the investment costs, fixed costs, variable production costs, and integration costs ($2.5/MWh for PV). The production costs are estimated using a detailed hourly chronological production cost model (PROMOD IV, Ventyx). The PVRR is estimated for each portfolio under various single-variable sensitivity scenarios (high and low natural gas prices, extension of renewable tax credits, high and low energy efficiency costs, and high externality costs). The base case portfolio with the lowest PVRR was selected as the preferred portfolio.

In procuring renewables, APS includes a quantitative analysis of bids that compares the cost of the bidder's proposal to the market cost of comparable conventional generation. The costs include the bid price, any transmission costs to deliver the power to APS, and an integration cost adder of $2.5/MWh for PV ($3.25/MWh for wind). The integration cost is meant to account for the cost imposed on APS of increased resources and regulating reserves due to resource intermittency and forecast uncertainty. The market cost of comparable conventional generation is the avoided capacity and energy cost to APS of producing the incremental electricity taking into account the hourly, seasonal, and long-term supply characteristics of the proposed facility. Bidders are required to submit expected hourly generation profiles (8,760 hr/yr) for the facility based on historical weather years. APS uses production cost modeling of its system to determine the market cost of comparable generation. The capacity credit is estimated using an approximation of the ELCC method where coincidence of generation with top load hours is used to identify the load-carrying capability of a resource. It is not clear how APS evaluates the capacity component of the avoided costs from conventional generation (the capacity value).

Category	Value
Solar technologies considered	Distributed fixed PV Utility-scale single-axis tracking PV CSP without thermal storage CSP with 6 hours of thermal storage Solar thermal gas hybrid plants
Solar capacity credit	Base estimates: 50% for fixed PV 65%-77% for single axis tracking PV 70% for CSP without thermal storage 100% for CSP with thermal storage (6 hours) or for solar thermal/gas hybrid plants These estimates change with penetration of solar in any candidate portfolio
Solar integration cost for resource selection	$2.5/MWh for PV, $0 for other solar technologies
Solar integration cost for portfolio evaluation	Same
Resolution of production cost model	Hourly over a full year with operational constraints

Portland General Electric:

Similar to APS, PGE uses engineering judgment to develop different portfolios of resources (15 portfolios). The portfolios are designed to demonstrate extreme bookends where a single resource is chosen to largely fulfill expected future needs (out to 2020) and to then compare those bookends to more diverse portfolios that include combinations of resources. A commercial capacity-expansion model is not used to design the portfolios.

The solar resources that are considered as candidate resources to be included in the portfolios included distributed rooftop PV or ground-mounted utility-scale PV. PGE did not apply separate distinct benefits to distributed PV, but did account for reduced line losses in the production cost modeling. The amount of PV included in each portfolio depended on engineering judgment. The relative attractiveness of different resource options was estimated in order to guide the selection of resources. PGE estimated the delivered cost of each resource in $/MWh terms with the cost for wind and solar adjusted by an integration cost and a capacity cost adder. The integration cost was $6.35/MWh based on the integration cost found for wind at low penetration (the integration cost for wind at the higher penetration levels now experienced by PGE was estimated to be $11.75/MWh in the 2009 wind integration study and revised to $7.96/MWh in the 2011 wind integration study). The capacity cost adder is based on the capital cost of simple cycle CTs needed to make the reliability contribution of solar (and wind) equivalent to the reliability contribution from a CCGT that has the same annual energy output (assuming the CCGT is dispatched as a baseload resource). PGE assumes the capacity credit of PV is 5% of the nameplate capacity (due to PGE being a winter night peaking load). The resulting capacity cost appears to add about $6–$10/MWh to the cost of the PV resources. The same capacity credit is used for wind.

Each portfolio is designed to have an equivalent amount of dependable capacity for various target years, including a 5% capacity contribution of PV and wind. Any remaining capacity necessary to meet the peak hour load and operating reserves after including any demand side measures is filled by simple-cycle CTs and/or on-peak market purchases. On-peak market purchases are limited to meet at most 300 MW of the capacity need in any scenario.

PGE developed a very sophisticated evaluation method to estimate a single metric that can be used to compare the different portfolios across several measures of cost effectiveness, risk and diversity, and reliability. The net PVRR for each portfolio is first estimated under a reference set of assumptions using an hourly production cost model (AURORAxmp, EPIS) and the capital cost of each portfolio (and the integration costs). The portfolios are also then subjected to two types of analysis approaches that evaluate the performance of the portfolios under different assumptions. The first, deterministic analysis varies individual assumptions regarding factors like future fuel prices, carbon prices and carbon price timing, availability of renewable tax incentives, and wholesale market prices. The second, a Monte-Carlo analysis, varies five input variables in a stochastic manner (with no expected correlation between these variables): WECC-wide load, natural gas prices, hydroelectric energy, plant forced outages, and wind production. Reliability metrics are also developed from these stochastic cases based on the amount of energy that PGE is not able to serve with its portfolio and instead relies on market purchases from other WECC resources. The performance of the portfolios in these various cases is then weighted and combined into one ranking score to determine the most attractive portfolio. The weightings are 20% based on reliability and diversity metrics, 30% based on portfolio risk metrics, and 50% based on expected cost.

When procuring renewable resources, PGE considers both price factors (60%) and non-price factors (40%). Both the price factors and non-price factors include information about the generation characteristics of solar. The price score is calculated as the ratio of the total bid cost per MWh to forecast market prices. According to PGE, its price scoring compares the market costs when the energy is delivered to the corresponding hourly projected market price. PGE adjusts the bid price based on whether the bidder includes the cost of providing fixed hourly schedules based on hour-ahead forecasts in order to schedule generation into PGE's system over the transmission network or if the bidder expects PGE to provide this balancing service. If PGE provides the balancing (e.g., the resource is directly connected to the PGE system or is dynamically scheduled to PGE) then PGE adds its expected cost of providing this service to the bid. The integration cost is $6.35/MWh in $2009 for solar based on the 2009 IRP integration cost. PGE requests both a monthly 24-hour average generation profile (12 X 24) and a full year of hourly generation data for each solar bid. The 12 X 24 profile represents the monthly energy and peak capacity of the project. PGE does not specify how it accounts for the capacity value of each bid based on the monthly peak capacity.

In addition to the price factors, PGE includes numerous non-price factors in the bid evaluation. Some of the non-price factors include issues related to solar variability and uncertainty. PGE awards the highest non-price score to bids that provide a flat volume of power for all hours. PGE also prefers to know as far in advance as possible the amount of energy to be supplied in any given hour (e.g., week ahead is better than day ahead which is better than hour ahead). PGE does not specify how it assigns a numeric non-price score within these categories, which makes it difficult to know if an inexpensive bid with solar's generation profile and hour-head scheduling would have a higher or lower overall (price and non-price) score than an expensive bid with a flat annual generation profile and week-ahead scheduling.

Category	Value
Solar technologies considered	Distributed and utility-scale PV
Solar capacity credit	5% for PV
Solar integration cost for resource selection	$6.35/MWh for PV
Solar integration cost for portfolio evaluation	Same
Resolution of production cost model	Hourly over a full year

Idaho Power:

Similar to APS and PGE, Idaho Power uses engineering judgment to develop different portfolios of resources (9 portfolios). The portfolios are designed to meet the capacity and energy deficits identified in each future year based on a loads and resource balance along with adding sufficient renewable energy to be able to meet a federal renewable energy standard, if one were to be enacted. A commercial capacity-expansion model is not used to design the portfolios.

The solar resources that were considered as candidate resources for the portfolios included fixed PV (1-MW and larger plant sizes with no consideration of separate benefits of distributed PV) and power towers with 7 hours of thermal storage. The amount of solar included in each portfolio depended on engineering judgment. The relative attractiveness of different resource options was estimated in order to guide the selection of resources. Idaho Power estimated the levelized cost in $/MWh terms (without consideration of integration costs, transmission costs, or any other adjustments) and separately in $/MW of peak hour capacity contribution, or the capacity credit. The capacity credit is estimated based on the capacity factor of each resource during the summer peak period between 3 and 7 pm. The capacity credit of fixed PV was estimated to be 36% of nameplate capacity, and the capacity credit of the power tower with thermal storage was 89%. No integration cost was estimated for the solar resources. Each portfolio is designed to have an equivalent amount of peak-hour capacity for various target years, including the peak hour capacity contribution of solar and wind.

Idaho Power compares the different portfolios based on the net PVRR less any revenues from the sale of excess renewable energy credits. The cost of each portfolio is first estimated under a reference set of assumptions using an hourly production cost model (AURORAxmp, EPIS) and the capital cost of each portfolio. Idaho Power then examines the change in the cost of each portfolio relative to the expected cost by varying the parameter for one uncertainty at a time with both a high case and a low case. The uncertainties include carbon prices, natural gas prices, capital cost, loads, and renewable energy credit prices. Finally Idaho Power used a Monte-Carlo analysis to examine the range and median cost of each portfolio using the same uncertainties as used in the deterministic cases but allowing carbon costs, natural gas prices, and REC prices to be positively correlated. The preferred portfolio had both the lowest expected cost of all portfolios and a relatively low spread of the costs in the Monte-Carlo analysis.

Category	Value
Solar technologies considered	Utility-scale fixed PV and solar power tower with 7 hours of thermal storage
Solar capacity credit	36% for PV 89% for solar power tower with 7 hours of thermal storage
Solar integration cost for resource selection	Not considered
Solar integration cost for portfolio evaluation	Not considered
Resolution of production cost model	Hourly over a full year

NV Energy:

NV Energy is a company formed in the merger of NV Power, which served loads primarily in southern Nevada, and Sierra Pacific, which served loads primarily in northern Nevada. At this time the former Sierra Pacific and NV Power entities file separate IRPs. This review summarizes only the southern Nevada plan covering NV Power's former area. Throughout the document, however, we refer to this as the NV Energy plan. Similar to APS, PGE, and Idaho Power, NV Energy uses engineering judgment to develop different portfolios of resources (four portfolios). NV Energy relies on short-term market purchases to maintain a planning reserve margin when the portfolio resources are insufficient. The short-term market prices include the capacity cost of a CCGT net any short-run profit that CCGT would earn selling its power into the wholesale power market.

The only solar resource considered as a candidate for the portfolios is fixed PV (20-MW plants). NV Energy is currently in a position to meet its RPS requirements with existing and contracted renewable resources. The only portfolio to include PV is a required low-carbon portfolio that includes wind and PV in addition to a common set of conventional generation that is included in all four portfolios (a mix of CTs and combined cycle natural gas turbines). It is not clear how NV Energy determined how much of each generation type to include in the portfolios. The contribution of fixed PV to meeting the planning reserve margin is estimated as 38% of the nameplate capacity. The capacity credit was based on an evaluation of PV generation during peak load periods conducted by Pacific Northwest National Laboratory for NV Energy. No integration cost was explicitly added due to the inclusion of PV in a portfolio, but NV Energy does increase the amount of operating reserve that is held in the production cost modeling based on the nameplate capacity of PV. The amount of increase is based on the results of a detailed PV integration study conducted for NV Energy. NV Energy also adjusted its peak demand load forecast according to their forecast of future customer-sited distributed PV and coincidence of PV output and peak load.

NV Energy compares the different portfolios based on the net PVRR and the net present value of the social cost (which includes the cost of externalities that are not already priced in the PVRR like NOx and particular matter emissions). The cost of each portfolio is first estimated under a reference set of assumptions using an hourly production cost model (PROMOD IV, Ventyx) and the capital cost of each portfolio. NV Energy then examines the change in the cost of each portfolio relative to the expected cost by varying the parameter for one uncertainty at a time. The uncertainties include carbon prices, natural gas and wholesale power prices, loads, and the ability to make off-system sales with NV Energy assets. The preferred portfolio was largely selected based on having the lowest expected revenue requirement and social cost.

In procuring resources NV Energy ranks resources based on relative cost. In the initial screening this includes comparing the proposed project's expected 12 month by 24 hour output profile against NV Energy's avoided cost. After the initial screening, additional detailed economic analysis is carried out. NV Energy does not specify whether its avoided costs include capacity costs nor does it outline what is included in the more detailed economic analysis.

Category	Value
Solar technologies considered	Utility-scale fixed PV
Solar capacity credit	38% for PV
Solar integration cost for resource selection	Not specified
Solar integration cost for portfolio evaluation	Implicitly included through increase in operating reserve requirement in production cost model
Resolution of production cost model	Hourly over a full year with operational constraints

Imperial Irrigation District:

IID manually developed five different portfolios of potential future resources to meet a growing gap between existing resources and forecasted peak loads and relatively high reliance on older, inefficient generation. All of the portfolios included a small amount of generic solar resources that would either be met by PV or a solar chimney. IID appears to assign a full 100% capacity credit to the solar resources. IID does not present any detailed cost comparison or ranking methodology to guide the selection of resources for the portfolios.

IID uses an hourly production cost model (PROSYM, Ventyx) to estimate the total revenue requirement of the portfolios under a common set of assumptions about the future. It is not clear how much of each year was simulated in the hourly production cost model. No sensitivity scenario with different assumptions is presented. IID's preferred portfolio is the portfolio with the lowest PVRR.

Category	Value
Solar technologies considered	PV and solar chimney
Solar capacity credit	100%
Solar integration cost for resource selection	Not considered
Solar integration cost for portfolio evaluation	Not considered
Resolution of production cost model	Hourly

Salt River Project:

SRP presents a single resource plan without comparing any alternative portfolios or presenting a forecast of the present value of the total revenue requirement of the plan. The plan is designed to meet a gap between existing resources and forecasted future demand while addressing several qualitative objectives. CSP and PV are both considered for the plan, and solar is included in the final plan, but no additional detail on the type of solar technology included in the plan is provided.

When gauging the attractiveness of resources to include in the plan, SRP appears to primarily base the relative merits of each resource option based on its levelized cost of energy plus a category called "integration, delivery, & risk premiums." This includes an integration cost for PV of about $45/MWh, a $5/MWh transmission cost for CSP, and a $40–$45/MWh capital cost risk for PV and CSP (the wind integration cost is similarly in the range of $40/MWh).

SRP does not describe the estimated capacity contribution of solar or appear to use a production cost model to estimate the variable costs of the preferred portfolio.

Category	**Value**
Solar technologies considered	PV and CSP
Solar capacity credit	Not available
Solar integration cost for resource selection	$45/MWh for PV
Solar integration cost for portfolio evaluation	Not available
Resolution of production cost model	Not available

Appendix B Derivation of Net Cost

B.1 Nomenclature

$\mathbb{E}$	Expectation operator
PVRR	Present value of the revenue requirement
Sets:	
T	Planning horizon of analysis
Ω	Potential futures
Parameters:	
FC	Present value of the fixed cost per unit of capacity ($/MW-yr)
α_ω	Probability of a future ω
P_s	Cost of involuntary load shedding or hourly cost of buying capacity on the market with short notice, discounted to present value terms ($/MWh)
MC	Variable cost of producing power, discounted to present value terms ($/MWh)
ϕ	Availability of a generator in each hour (between 0 and 1)
L	Hourly load
L_p	Peak load and planning reserve margin for resource adequacy
CC	Capacity credit for resource adequacy (between 0 and 1)
CF	Hourly capacity factor of variable generator (between 0 and 1)
E	Hourly energy generation of variable generator ($CF \cdot k$, MWh)
Variables:	
g	Hourly generation
l_s	Hourly involuntarily load shedding
s	Slack variable that is positive only when a generator output is less than the full amount available
k	Nameplate capacity of a generation resource (MW)
Dual Variables or Shadow Prices on Constraints:	
p	Hourly shadow value of load balance constraint; wholesale power price or system lambda
π	Hourly shadow value of generation capacity limit for each generator
μ_k	Shadow value of resource adequacy constraint
Results:	
$\bar{c}$	Reduced cost of a variable ($/MW-yr)
$\bar{C}$	Reduced cost of a variable ($/MWh)

The LSE planner problem is as follows: given a set of uncertain futures, determine the portfolio of resources that leads to the lowest expected present value of the revenue requirement. The solution to this problem is called the preferred portfolio.

B.2 Planning problem with no adequacy requirement

In the most simple case, the planner must determine the portfolio that leads to the lowest revenue requirement without consideration of any adequacy requirement. If insufficient generation is available at any point in time, load will be involuntarily shed or the LSE will need to procure energy from the market on short notice. In either case the cost of this is assumed to be very high. This will tend to push the LSE toward procuring sufficient capacity in the preferred portfolio in order to minimize these high costs.

The planning problem can be mathematically defined as a linear program in standard form as follows:

Objective function:

$$
\begin{aligned}
&\min \quad \mathbb{E}\left[PVRR\right] \\
&= \min \quad FC_v k_v + \sum_i FC_i k_i + \sum_\omega \alpha_\omega \sum_t P_s l_s^{\omega,t} + \sum_i MC_i^\omega g_i^{\omega,t}
\end{aligned}
$$

Load Balance,
$\forall t \in T, \omega \in \Omega:$

$$\left[\text{dual: } \alpha_\omega p^{\omega,t}\right] \qquad CF_v^{\omega,t} k_v + l_s^{\omega,t} + \sum_i g_i^{\omega,t} = L^{\omega,t}$$

Generator Capacity,
$\forall t \in T, \omega \in \Omega, i \in I:$

$$\left[\text{dual: } \alpha_\omega \pi_i^{\omega,t}\right] \qquad -\phi_i^{\omega,t} k_i + g_i^{\omega,t} + s_i^{\omega,t} = 0$$

Non-negativity:

$$k_v, \quad k_i, \quad l_s^{\omega,t}, \quad g_i^{\omega,t}, \quad s_i^{\omega,t} \geq 0$$

(1)

This same problem can be restated in words as:

Objective Function	Minimize the sum of the annualized fixed cost of capacity and the expected dispatch cost (including any high costs of involuntary load shedding or procuring capacity from the market on short notice)
Load Balance Constraint	In every hour and in every future the generation from the variable generation and the dispatchable generation must be in balance with the load. If they are not in balance then load must be involuntarily shed or power must be bought on short notice from the market.
Generation Capacity Constraint:	The amount of generation from a generator in any hour must be less than or equal to the amount of available generation capacity in that hour. If it is less than the amount of available generation then the slack variable must be positive.

B.2.1 Solution: Least-cost portfolio without adequacy requirement

Since this problem can be stated as a linear program, there are certain features of the solution to this problem (e.g. the least cost portfolio) that must be true (Bertsimas and Tsitsiklis 1997).

First, every variable will have what is called a "reduced cost". This is defined as the change in the objective value function (i.e., the expected present value of the revenue requirement) for a small increase or decrease in the variable away from the optimal value. The "reduced cost" of a generator that is not included in the preferred LSE portfolio, for example, represents how much the expected PVRR would increase if a small amount of capacity of that generator were forced into to the portfolio and a new least-cost portfolio were found (given the forced-in high cost generation).

This is the same as the definition of the "net cost" used in the main document. When the problem is defined in the standard form for linear programming (Eq. 2), the "reduced cost" for a variable j is given by Eq. 3.

$$\begin{aligned} \min \quad & \mathbf{c}'\mathbf{x} \\ \text{s.t.} \quad & \mathbf{A}\mathbf{x} = \mathbf{b} \\ & \mathbf{x} \geq \mathbf{0} \end{aligned} \tag{2}$$

$$\bar{c}_j = c_j - \mathbf{v}'\mathbf{A_j} \tag{3}$$

In words, Eq. 3 states that the reduced cost of any variable is defined as the cost coefficient of that variable in the objective function less the product of the dual value of each constraint ($\mathbf{v}$) and the constraint coefficient for that variable ($\mathbf{A_j}$).

The reduced cost formula can be used to estimate how much the expected PVRR will increase if a variable generator is not part of the preferred portfolio, but the variable generation is added to the portfolio and a new least cost portfolio is found with the addition of that variable generator. The cost coefficient of the variable generation capacity variable in the objective function is the annualized fixed cost of the variable generator (FC_v). Since the only constraint that includes the capacity of the generator is the "Load Balance" constraint, the product of the dual variables of that constraint ($\alpha_\omega p^{\omega,t}$) and the constraint coefficient ($CF_v^{\omega,t}$) is simply the sum of $\alpha_\omega p^{\omega,t} CF_v^{\omega,t}$ over all hours and all futures. Since $p^{\omega,t}$ is the dual of the load balance constraint, $p^{\omega,t}$ can be interpreted as the hourly wholesale price for power for a particular future. The product $p^{\omega,t} CF_v^{\omega,t}$ can be described simply as the coincidence of wholesale prices and variable generation. The general formula for the reduced cost, Eq. 3, can then be used to find the reduced cost of the variable generation capacity included in the portfolio (assuming there is no adequacy requirement for the LSE), Eq. 4.

$$\bar{c}_v = FC_v - \sum_\omega \alpha_\omega \sum_t p^{\omega,t} CF_v^{\omega,t} \tag{4}$$

This result can be interpreted as follows. The amount that the LSE's expected present value of the revenue requirement will increase when variable generation is added to the preferred portfolio is the difference between the annualized fixed cost of the variable generator and the weighted average over all possible futures of the coincidence of wholesale power prices and the output of variable generation.

In some cases it can me more intuitive to understand the annualized fixed cost in terms of the levelized cost per unit of energy (LCOE) instead of the annualized cost per unit of capacity ($/MW-yr). The LCOE is simply the annualized fixed cost divided by the annual generation of a 1 MW variable generation plant ($CF_v 8760 h/yr$).

Dividing both sides of Eq. 4 by the annual generation of a 1 MW variable generation plant then leads to the following modified results in the more intuitive $/MWh form in Eq. 5

$$\bar{C}_v = LCOE_v - \sum_\omega \alpha_\omega \frac{\sum_t p^{\omega,t} E_v^{\omega,t}}{\sum_t E_v^{\omega,t}} \tag{5}$$

The result is somewhat different if the LSE uses a resource adequacy requirement in determining their preferred portfolio.

B.3 Planning problem with a resource adequacy requirement

Often LSEs require that any feasible portfolio must satisfy a resource adequacy constraint—the sum of the capacity contribution from resources any portfolio must equal the peak load plus a planning reserve margin—when identifying the preferred portfolio. This results in a slightly modified planning problem as shown below.

Objective function:

$$
\begin{aligned}
&\min \quad \mathbb{E}\left[PVRR\right]\\
&= \min \quad FC_v k_v + \sum_i FC_i k_i + \sum_\omega \alpha_\omega \sum_t P_s l_s^{\omega,t} + \sum_i MC_i^\omega g_i^{\omega,t}
\end{aligned}
$$

Load Balance,
$\forall t \in T, \omega \in \Omega :$

$$
\left[\text{dual: } \alpha_\omega p^{\omega,t}\right] \quad CF_v^{\omega,t} k_v + l_s^{\omega,t} + \sum_i g_i^{\omega,t} = L^{\omega,t}
$$

Generator Capacity,
$\forall t \in T, \omega \in \Omega . i \in I :$

$$
\left[\text{dual: } \alpha_\omega \pi_i^{\omega,t}\right] \quad -\phi_i^{\omega,t} k_i + g_i^{\omega,t} + s_i = 0
$$

Adequacy Requirement,
$\forall t \in T, \omega \in \Omega :$

$$
\left[\text{dual: } \mu_k\right] \quad CC_v k_v + \sum_i CC_i k_i = L_p
$$

Non-negativity:

$$
k_v, \quad k_i, \quad l_s^{\omega,t}, \quad g_i^{\omega,t}, \quad s_i^{\omega,t} \geq 0
$$

(6)

The resource adequacy constraint can be restated in words as:

Resource adequacy constraint	The capacity contribution from the variable generators and the conventional generation (defined as the capacity credit times the nameplate capacity) must equal the peak load plus planning reserve margin target.

B.3.1 Solution: Least-cost portfolio with an adequacy requirement

The addition of a new resource adequacy constraint changes the formula used to estimate the reduced cost of any variable, including the variable generator, since the new resource adequacy constraint adds both a new dual variable (μ_k) and a new constraint coefficient for the variable generator (CC_v). The change in the expected PVRR with the addition of variable generation is then given by the revised reduced cost, Eq. 7. The change in the expected PVRR must now also account for the capacity credit assigned to the variable generator in the resource adequacy assessment.

$$
\bar{c}_v = FC_v - \left(\mu_k CC_v + \sum_\omega \alpha_\omega \sum_t p^{\omega,t} CF_v^{\omega,t}\right) \tag{7}
$$

In order to interpret this new formula for estimating the reduced cost we must now try to understand the shadow value of the resource adequacy constraint or the dual variable μ_k. First, if the resource adequacy constraint is not binding, meaning that the resource adequacy constraint is satisfied automatically, then the dual variable of the constraint, μ_k, is zero and the reduced cost of the variable generator remains the same as before, without the resource adequacy constraint. On the other hand, when then constraint is binding, the dual variable μ_k will be non-zero and the reduced cost of the variable generator will be different than what would be calculated without consideration of the resource adequacy constraint.

In the case that the resource adequacy constraint is binding, we now turn to the estimation of the numerical value of the dual variable μ_k. Another helpful point in this regard is that for any variable included in the least-cost portfolio, the "reduced cost" of that variable must be equal to 0: if it were negative then adding more of that variable wound decrease the expected PVRR and hence the original portfolio wouldn't have been the least-cost portfolio. Conversely, if the reduced cost were positive then the addition of that variable to the portfolio causes the expected PVRR to increase, no longer making it the least-cost portfolio (since the expected PVRR has increased).This point can be used to better understand the value of μ_k for any generator included in the least cost portfolio.

Using the definition of the reduced cost in Eq. 3, we can calculate the reduced cost of any conventional generation capacity as:

$$\bar{c}_i = \boldsymbol{FC}_i - \left(\mu_k \boldsymbol{CC}_i - \sum_{\omega} \alpha_{\omega} \sum_{t} \pi_i^{\omega,t} \phi_i^{\omega,t} \right) \tag{8}$$

For any conventional generation capacity that is included in the preferred portfolio, the reduced cost of that generation capacity $\bar{c}_i$ will be equal to zero. In that case, for any generation capacity included in the preferred portfolio the following will hold:

$$\mu_k \boldsymbol{CC}_i = \boldsymbol{FC}_i + \sum_{\omega} \alpha_{\omega} \sum_{t} \pi_i^{\omega,t} \phi_i^{\omega,t} \tag{9}$$

The dual variable for the generator capacity constraint, $\alpha_\omega \pi_i^{\omega,t}$ indicates the degree to which the expected PVRR would change if more capacity of generator i were available in a particular future, ω, at a particular point in time, t. In hours where the generator is dispatched below its available capacity in that hour (such that $g_i^{\omega,t} < \phi_i^{\omega,t} k_i$) then the slack variable indicating how far below the available capacity the generator is dispatched, $s_i^{\omega,t}$, is positive and its reduced cost, $\bar{c}_{s_i^{\omega,t}}$, must then be zero. Using Eq. 3, the reduced cost of the generator slack variable is:

$$\bar{c}_{s_i^{\omega,t}} = 0 - \alpha_\omega \pi_i^{\omega,t} \tag{10}$$

In those hours when the generator i is dispatched below its capacity, Eq. 10 then implies that $\pi_i^{\omega,t}$ must be equal to zero.

Similarly in any hour when the generator is used to generate power (such that $g_i^{\omega,t} > 0$), the reduced cost of the generator output must be zero. Using Eq. 3, the reduced cost of the generator output is:

$$\bar{c}_{g_i^{\omega,t}} = \alpha_\omega MC_i^\omega - \alpha_\omega p_i^{\omega,t} - \alpha_\omega \pi_i^{\omega,t} \tag{11}$$

In hours when the generation is positive, the reduced cost is zero and the the following must hold:

$$\pi_i^{\omega,t} = MC_i^\omega - p_i^{\omega,t} \tag{12}$$

During the periods when the slack variable is positive and the generator output is zero (indicating the generator is being used but the capacity constraint is not binding) both Eq. 10 and Eq. 12 must hold indicating that the wholesale power price in those hours, $p_i^{\omega,t}$, must equal the variable cost of the generator, MC_i^ω.

From the evaluation of the reduced cost of the generator slack variable s_i and the generator output, g_i, for a particular generator it is clear that time period can be partitioned into two mutually exclusive periods: (1) period T_0 where s_i is positive the such that the generator capacity constraint not binding and $\pi_i^{\omega,t}$ is equal to zero or (2) period T_k where the generator capacity constraint is binding and $\pi_i^{\omega,t}$ is the difference between the variable cost of the generator and the wholesale power price, $MC_i^\omega - p_i^{\omega,t}$. This information can be used to simplify the relationship describing the dual variable of the resource adequacy constraint for a generator that is included in the preferred portfolio, shown earlier in Eq. 9:

$$\mu_k CC_i = FC_i + \sum_{\omega} \alpha_\omega \left(\sum_{t \in T_0} 0 \cdot \phi_i^{\omega,t} + \sum_{t \in T_k} \left(MC_i^{\omega} - p_i^{\omega,t} \right) \phi_i^{\omega,t} \right) \tag{13}$$

Simplifying this relationship leads to:

$$\mu_k CC_i = FC_i - \sum_{\omega} \alpha_\omega \sum_{t \in T_k} \left(p_i^{\omega,t} - MC_i^{\omega} \right) \phi_i^{\omega,t} \tag{14}$$

This relationship indicates that the dual of the capacity constraint, μ_k, largely depends on the annualized fixed cost of any generation capacity included in the preferred portfolio less the amount that the wholesale power price exceeds the variable cost of that generation.

In a very simplified case where the preferred portfolio includes new peaking generation that is never fully dispatched to its full capacity, k_{peak}, and the new peaking generation has a capacity credit equal to its nameplate capacity the dual of the resource adequacy constraint would be further simplified to:

$$\mu_k = FC_{peak} \tag{15}$$

Since the new peaking generation is never dispatched to its full capacity, Eq. 10 indicates that π_{peak}, the dual of the peaker plant capacity constraint, is always equal to zero. Since the reduced cost of any variable is greater than or equal to zero (otherwise the preferred portfolio wouldn't be the least cost portfolio) then Eq. 11 also indicates that the wholesale prices must always be less than or equal to the variable cost of the peaker plant.

The change in the expected PVRR with the addition of variable generation in the case that such a peaker plant is included in the preferred portfolio can then be found using Eq. 7 and Eq. 15:

$$\bar{c}_v = FC_v - \left(\overbrace{FC_{peak} CC_v}^{\text{capacity value}} + \overbrace{\sum_{\omega} \alpha_\omega \sum_{t} p^{\omega,t} CF_v^{\omega,t}}^{\text{energy value}} \right) \tag{16}$$

This result can be interpreted as follows. The amount that the LSE's expected present value of the revenue requirement will increase when variable generation is added to the preferred portfolio is the difference between the annualized fixed cost of the variable generator and the sum of the capacity value and the energy value of the variable generator. The capacity value is the product of the annualized fixed cost of a peaker plant included in the preferred portfolio and the capacity credit of the variable generator. The energy value is the weighted average over all possible futures of the coincidence of wholesale power prices and the output of variable generation. The wholesale prices, furthermore, never exceed the variable cost of the peaker plant.

Dividing both sides of Eq. 16 by the annual generation of a 1 MW variable generation plant then leads to the following modified results in the more intuitive \$/MWh form in Eq. 17

$$\bar{C}_v = LCOE_v - \left(\overbrace{\frac{FC_{peak}}{\text{8760h/yr}} \frac{CC_v}{CF_v}}^{\text{capacity value}} + \overbrace{\sum_{\omega} \alpha_\omega \frac{\sum_t p^{\omega,t} E_v^{\omega,t}}{\sum_t E_v^{\omega,t}}}^{\text{energy value}} \right) \tag{17}$$

In a more general case where a peaker plant with such stringent requirements (full capacity credit, never fully dispatched) is not included in the preferred portfolio, then the amount that the LSE's expected present value of the revenue requirement will increase when variable generation is added to the preferred portfolio is given by Eq. 18, based on Eq. 7 and Eq. 14. In the more general case, the wholesale power prices may increase above the variable cost of the generator i when the generator output is equal to its capacity.

$$\bar{c}_v = FC_v - \left(\overbrace{\left(FC_i - \sum_{\omega} \alpha_\omega \sum_{t \in T_k} \left(p_i^{\omega,t} - MC_i^{\omega} \right) \phi_i^{\omega,t} \right) \frac{CC_v}{CC_i}}^{\text{capacity value}} + \overbrace{\sum_{\omega} \alpha_\omega \sum_{t} p^{\omega,t} CF_v^{\omega,t}}^{\text{energy value}} \right) \tag{18}$$

B.3.2 Solution: Conventional generation resource

For any conventional generation resource included in the preferred portfolio, the reduced cost of the generation capacity is zero. The reduced cost of any conventional generation resource that is not included in the preferred portfolio, generator n, can be calculated using the same approach as described for the variable generator.

Earlier we started with the equation for the reduced cost, Eq. 3, and then came up with the reduced cost for conventional generation capacity, Eq. 8. For generator n we recreate that equation again here for clarity.

$$\bar{c}_n = FC_n - \left(\mu_k CC_n - \sum_{\omega} \alpha_\omega \sum_{t} \pi_n^{\omega,t} \phi_n^{\omega,t} \right) \tag{19}$$

For any conventional generator i that is included in the preferred portfolio we can find the value of μ_k, the dual of the resource adequacy constraint, using Eq. 14. In the very simplified case where a peaker plant is included in the preferred portfolio, the dual value of the resource adequacy constraint is reduced to FC_{peak} according to Eq. 15.

Similar to the earlier discussion the time period can be partitioned into a period where the slack variable for the generator n would be positive, and the dual variable of the generator n capacity constraint, $\pi_n^{\omega,t}$, would be zero. In the rest of the year when the generator output is positive and its output is equal to the nameplate capacity limit of generator n is binding the dual value of the generator n capacity constraint becomes:

$$\pi_n^{\omega,t} = MC_n^{\omega} - p_n^{\omega,t} \tag{20}$$

The reduced cost of the conventional generator that is not included in the preferred portfolio can then be simplified to the following relationship:

$$\bar{c}_n = FC_n - \left(\overbrace{FC_{peak} CC_n}^{\text{capacity value}} + \overbrace{\sum_{\omega} \alpha_\omega \sum_{t \in T_n} \left(p^{\omega,t} - MC_n^{\omega} \right) \phi_n^{\omega,t}}^{\text{energy value}} \right) \tag{21}$$

This is essentially the same method for calculating the reduced cost for the variable generator in Eq. 16. The main difference is that the energy value term must now account for the difference between the wholesale price and the variable production cost of the conventional generation source. Further the availability of the conventional generator must also be accounted for.

The reduced cost of the generator per unit of energy produced, $\bar{C}_n$, can also be specified for comparison to the reduced cost per unit of energy from the variable generator.

$$\bar{C}_n = \frac{FC_n}{CF_n 8760\text{h/yr}} - \left(\overbrace{\frac{FC_{peak}}{8760\text{h/yr}} \frac{CC_n}{CF_n}}^{\text{capacity value}} + \overbrace{\frac{1}{CF_n 8760\text{h/yr}} \sum_{\omega} \alpha_\omega \sum_{t \in T_n} \left(p^{\omega,t} - MC_n^{\omega} \right) \phi_n^{\omega,t}}^{\text{energy value}} \right) \tag{22}$$