# Western Interconnection Flexibility Assessment

## Interim Project Report

April 2015

Energy+Environmental Economics

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# Disclaimer and Acknowledgement

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# About this Study

This study was jointly undertaken by the Western Electricity Coordinating Council (WECC) and the Western Interstate Energy Board (WIEB) to investigate the need for power system flexibility to ensure reliable and economic operations of the interconnected Western electricity system under higher penetrations of variable energy resources. WECC and WIEB have partnered with E3 and the National Renewable Energy Laboratory (NREL) to investigate these questions using advanced, stochastic reliability modeling and production simulation modeling techniques on NREL's High Performance Computing (HPC) environment. The study identifies and examines operational challenges and potential enabling strategies for renewable integration under a wide range of operating conditions, scenarios, and sensitivities across the Western Interconnection, with the goal of providing guidance to operators, planners, regulators and policymakers about changing system conditions under higher renewable penetration.

Funding for this project is provided by a number of sources. E3's role in the project is funded jointly by WECC and WIEB through grants received under the Department of Energy's American Recovery and Reinvestment Act (ARRA); NREL's role is funded directly by the Department of Energy.

## Technical Review Committee

This study was overseen by a technical advisory committee with the following members:

- Aidan Tuohy, Electric Power Research Institute
- Ben Kujala, Northwest Power and Conservation Council
- Brian Parsons, Western Grid Group
- Fred Heutte, Northwest Energy Coalition
- James Barner & Bingbing Zhang, Los Angeles Department of Water & Power
- Jan Strack, San Diego Gas & Electric
- Jim Baak, Vote Solar Initiative
- Justin Thompson, Arizona Public Service
- Keith White, California Public Utilities Commission
- Mike Evans, Shell Energy North America
- Thomas Carr, Western Interstate Energy Board
- Thomas Edmunds, Lawrence Livermore National Laboratory
- Tom Miller, Pacific Gas & Electric

The study team has met with this group throughout the study process to date to seek guidance on technical modeling assumptions and feedback on preliminary results. The TRC will remain engaged in reviewing findings and results as the project progresses through completion.

## Executive Advisory Group

This study also convened and sought input from a group of industry executives and representatives from around the Western Interconnection, including:

- Bill Gaines, Tacoma Power & Light
- Doug Larson, Western Interstate Energy Board
- Gregg Lemler, Pacific Gas & Electric
- Kimberly Harris, Puget Sound Energy
- Mark Rothleder, California Independent System Operator
- Mike Hummel, Salt River Project
- Rebecca Wagner, Nevada Public Utilities Commission
- Stacey Kusters, NV Energy

The Executive Advisory Group was convened with the purpose of helping to shape the scope of the study in order for its results and conclusions to be of relevance to decision-makers in the industry. The role of the Executive Advisory Group will expand as the study progresses to the phase of results review.

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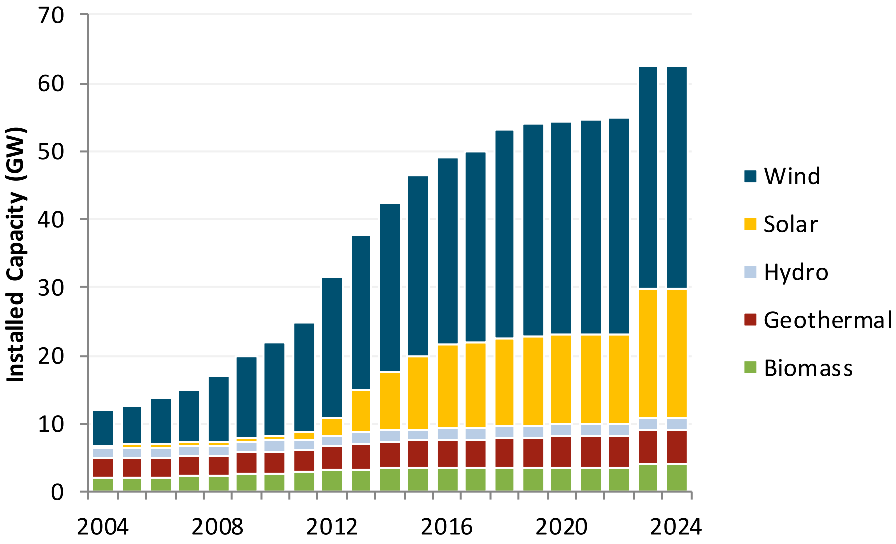
# 1 Introduction

## 1.1 Study Motivation

Over the course of the past decade, the penetration of renewable generation in the Western Interconnection has grown rapidly: during this time, nearly 30,000 MW of renewable generation capacity—mostly solar and wind—have been built within the footprint of the Western Interconnection (see Figure 1), increasing the total amount of renewable installed capacity by a factor of four. Much of this increase has been driven by the states' pursuit of Renewables Portfolio Standards (RPS), which specify a minimum share of load that each utility must serve with renewable generation. By 2024, under current state policies, the total installed capacity of renewable generation in the Western Interconnection may exceed 60,000 MW.

**Figure 1. Historical & projected growth of renewables in the Western Interconnection under current RPS policies.**



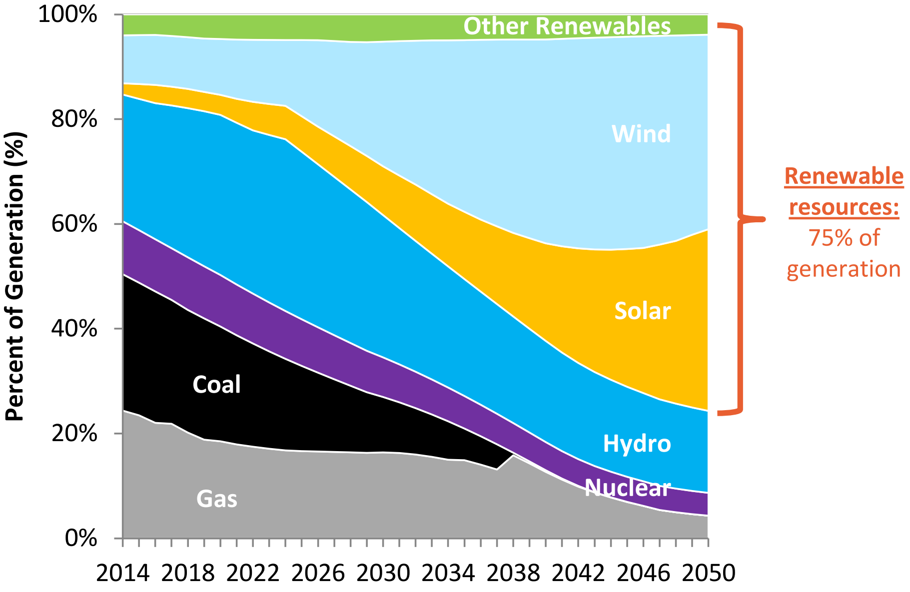
***Data Source: WECC 2024 Common Case***

Yet even as renewable development continues at unprecedented rates in pursuit of current policy targets, many have begun to look beyond these levels, anticipating an even more central role for renewables in the Western Interconnection:

- California's AB327, enacted in 2013, established that its 33% RPS target was intended as a floor, rather than a ceiling, on renewable procurement. More recently, California's governor announced a new goal of 50% renewables by 2030.
- Elsewhere in the Western Interconnection, technology cost reductions have allowed renewable resources to compete with conventional resources on an economic basis, and utilities in the Rocky Mountain region have signed power purchase agreements for wind generation in excess of current RPS targets on the basis of this advantage.

- The Environmental Protection Agency's proposed regulations on greenhouse gas emissions under Section 111(d) of the Clean Air Act would require individual states to develop implementation plans to meet 2030 emissions standards; one of the key "building blocks" of the proposed legislation is the displacement of existing fossil resources with new renewable generation.
- A burgeoning interest in policies to address climate change mitigation has intensified the focus on the long-term role of renewables in the West, as a number of studies have highlighted the central role that renewable generation may play in the decarbonization of the electric sector, a crucial step in the achievement of long-term carbon goals (see Figure 2, based on analysis in from IDDRI's *Pathways to Deep Decarbonization in the United States*). By 2050, achieving deep decarbonization of the economy could require low-carbon generation to account for 80-90% of total power supply, which would imply a dramatic acceleration of current renewable policy. In the Western Interconnection, aggressive decarbonization could result in renewable penetrations between 75-80%.

Figure 2. Potential role of renewable generation in long-term decarbonization of electric sector.[1]



**Data source:** **E3 PATHWAYS High Renewables Case**

With growing penetrations of renewable resources, new challenges will arise for resource planners and operators. Wind and solar resources, which will likely account for a significant share of the additional renewable generation in the Western Interconnection, are characterized by three key attributes that have important implications for power system operations:

- **Variability:** production changes from moment to moment, and from hour to hour;

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[1] Figure shows the mix of generation in the Western Interconnection for the "High Renewables" deep decarbonization pathway. Available at: http://unsdsn.org/wp-content/uploads/2014/09/US_DDPP_Report_Final.pdf

- **Uncertainty:** production over a given period of time cannot be predicted with perfect accuracy; and
- **Concentration:** production is highly concentrated during certain hours of the year in which the resource is available.

As the penetrations of variable renewable resources in the Western Interconnection continue to increase, planners must confront the question of how to build and operate a reliable system in which a large portion of the energy available has these qualities.

In order to explore the implications of such changes on generation planning and system operations, this study presents a comprehensive framework using a combination of loss-of-load-probability and production simulation modeling techniques through which the reliability and flexibility of a generation fleet may be evaluated under any penetration of renewable generation. This framework is applied to two scenarios: a Base Case that captures current state renewable policies and a High Renewables Case that includes additional renewable generation throughout the Western Interconnection. In doing so, this study seeks to achieve three goals:

- **Assess the ability of the fleet of resources in the Western Interconnection to accommodate high renewable penetrations while maintaining reliable operations.** Current state policies are expected to drive substantial change in the electric sector in the coming decade, but greater changes still may be on the horizon. Higher penetrations of renewable generation will test the flexibility of the electric systems of the West, requiring individual power plants to operate in ways that they have not historically and changing the dynamics of wholesale power markets. This study aims to identify the major changes in operational patterns that may be experienced at such high penetrations and to measure the magnitude and frequency of possible challenges that may result.

- **Investigate potential enabling strategies to facilitate renewable integration that consider both institutional and physical constraints on the Western system.** Existing literature has identified a wide range of possible strategies that may facilitate the integration of high penetrations of renewables into the Western Interconnection. These strategies comprise both institutional changes—increased use of curtailment as an operational strategy and greater regional coordination in planning and operations—as well as physical changes—new investments in flexible generating resources and the development of novel demand side programs. This study examines how such strategies can play an enabling role as the penetration of renewable generation continues to increase.
- **Provide lessons for future study of system flexibility on the relative importance of various considerations in planning exercises.** The study of flexibility and its need at high renewable penetrations is an evolving field. This effort is designed with an explicit goal of providing useful information to modelers and technical analysts to improve analytical capabilities for further investigation into the topics explored herein.

## 1.2 Prior Renewable Integration Studies

There have been a number of prior efforts to examine the impacts of high penetrations of renewables on the Western Interconnection. Each study examined this question through its own lens:

- The California Independent System Operator (CAISO) conducted a technical analysis of the ability of the CAISO system to integrate renewables to meet a 20% RPS: **Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS (CAISO 2010)**. This analysis identified increased ramping, increased operating reserve requirements, and overgeneration as potential consequences of increased wind and solar penetration. This study also flagged out-of-market scheduling as a potential constraint in efficiently integrating renewables and inadequate compensation for generators through energy markets as an emerging challenge under higher wind and solar penetrations.
- As part of its ongoing engagement in the California Public Utilities Commission's (CPUC) Long-Term Procurement Proceeding, the CAISO has continued to investigate the implications of increased renewable penetrations with respect to the need for new flexible generation capacity to facilitate renewable integration through production simulation modeling. The CAISO has studied a number of portfolios at 33% and 40% penetration, identifying shortfalls in operating reserves and the need to curtail renewable generation as possible consequences of higher renewable penetrations.
- The **Western Wind and Solar Integration Study (NREL 2010)** examined operations across the Western Interconnection with 35% penetration of wind & solar energy west-wide. This study identified geographical diversity, renewable forecasting for operations, and subhourly generation and interchange scheduling as key strategies to alleviating integration challenges across the West.
- **Investigating a Higher Renewables Portfolio Standard in California (E3 2013)** conducted on behalf of the five largest utilities in California investigated the operational challenges of meeting a 50% RPS. This study found that between 33% and 50% RPS, oversupply would emerge

as a new operational challenge (in some hours, renewable supply plus must-run generation exceeds load). This study identified renewable portfolio diversity, regional coordination, and resources that could provide downward flexibility as most promising for meeting a 50% RPS in California.

- The **Low Carbon Grid Study – Phase 1 (NREL 2014)** showed that a diverse renewable portfolio, regional coordination, flexible loads, and energy storage could be effective at alleviating renewable integration challenges in California at 50-55% renewables.
- **Regional Transmission Plan (TEPPC).** TEPPC has historically studied a number of scenarios that posit the expansion of renewable resources in the West to levels at and above current policy. The analysis in these studies has focused on identifying potential changes in interregional transmission flows as well as potential interregional transmission upgrades that might facilitate the delivery of renewable generation from different parts of the Western Interconnection to loads.

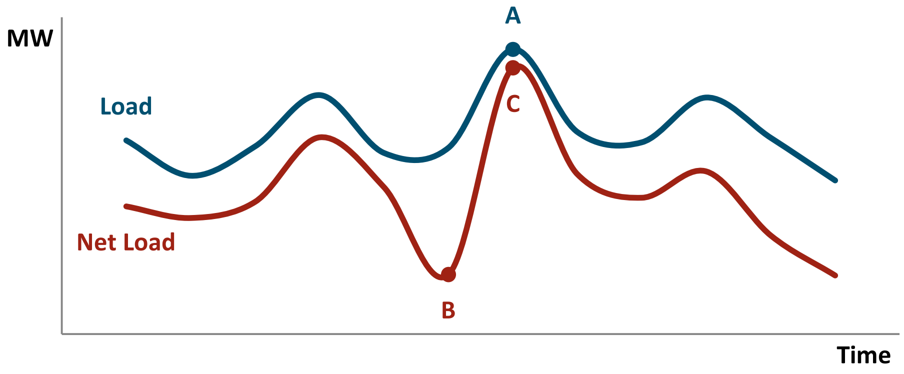
While these studies had different focuses, they have identified similar challenges and opportunities around the level of coordination in operations across the West and the extent to which renewables could be integrated efficiently by electricity markets. Because the Western Interconnection represents not a single market, but a conglomerate of independently operated investor-owned utilities, public utilities, and the CAISO, some level of operational coordination between these entities will be required to efficiently integrate renewables at higher penetrations. What has not yet been explicitly investigated is how this coordination (or lack thereof) might impact the planning of electricity systems across the West, a question of interest to WECC, WIEB, and their stakeholders.

## 1.3 Flexibility Planning Paradigm

While operational simulations are necessary to address renewable integration challenges, this assessment differs from prior studies in that it takes the perspective of the electric system resource planner. It examines not only how technical constraints on operations may impact the integration of renewables, but how institutional barriers and uncertainties may affect planning decisions as well.

Historically, resource planning for system reliability has generally focused on ensuring the adequacy of generation supply to meet loads during peak periods. A large majority of the capacity that exists today in the West is “dispatchable”: available to produce power at a level prescribed by the system operator on demand (within a given range). In this type of system, the peak load period corresponds to the time of year when the reliability of the system is most vulnerable (point A in Figure 3), as either a shortage of supply or an extreme peak event could trigger a loss of load. The focus on planning for the peak period was justified in the sense that a fleet capable of meeting the highest possible load throughout the year would be able to serve lower loads throughout the rest of the year reliably as well.

Figure 3. Illustrative diagram of the need for flexibility.



With increasing penetrations of variable resources, system operators will still face the task of ensuring reliability during peak periods but will face an additional challenge of ensuring sufficient operational flexibility to meet load under rapidly changing conditions. In these systems, operators must respond to signals in "net load"—demand net of variable resources—rather than that of simply load itself. Higher penetrations of variable resources magnify both the variability and uncertainty of the net load; in such an environment, systems must be capable of operating with sufficient flexibility to respond to potentially large changes in the net load (i.e. move from point B to point C in Figure 3, or, more generally, between any two plausible sequential states of net load).

The need for flexibility in power system operations is not entirely new: operators have historically dispatched generators to respond to hourly changes in load and have held operating reserves to accommodate errors in load forecasts and subhourly variability. The novelty of the flexibility challenge at high penetrations of renewables is in the increased amount of flexibility needed: variable resources increase both the magnitude and frequency of large ramps in net load as well as the uncertainties that an operator must accommodate. In such an environment, the question of how to design and operate a system with sufficient flexibility while mitigating costs to ratepayers and ensuring reliability becomes a central focus rather than a secondary goal to traditional resource adequacy.

Anticipating the growth of variability and uncertainty in net load, a planner seeking to ensure flexibility adequacy must consider how to ensure that the necessary operational flexibility is available. Flexibility in operations—and by extension, the reliable service of load—may be provided by a number of sources:

- **Utilize flexibility offered by existing dispatchable resources.** A large portion of the existing resources in the Western Interconnection are dispatchable, and their output may be varied over time within operating limits (minimum and maximum output, minimum up and down times, and, start times, and ramp limitations). In some cases, existing resources may be fully prepared to operate flexibly; in other cases, technical changes and/or investments may be necessary to enable greater flexibility from existing resources.
- **Use interties with neighboring areas to import and/or export energy as needed.** The Western Interconnection has neither a centralized planning authority nor a central optimized dispatch of resources across its footprint; most of the interregional trade in the West occurs through bilateral transactions. Planners in the future will be faced with the policy question of the extent to which they are willing to rely on the flexibility of their neighbors rather than that provided by their own native resources.

- **Curtail output of renewable generators.** If the power system is insufficiently flexible to accommodate all net load conditions, the system operator may be forced to curtail renewable energy output in order to preserve bulk system reliability. This may need to be accomplished in real time in response to oversupply conditions, or may need to occur prospectively in order to ensure that the system can meet potential upward ramping needs. For example, in the illustrative example of Figure 3, if the generation fleet does not have the capability to ramp from B to C in the required time, curtailment of renewable generation could increase the net load at point B and may help the system meet the upward ramp to point C. While the curtailment of renewable generation results in some lost value to ratepayers, there will be instances—especially as penetrations increase—where the operational value of curtailing renewables outweighs the lost value to ratepayers. Efficient use of curtailment to may require new market structures and contractual agreements.
- **Invest in new flexible generation infrastructure and/or demand-side programs.** Investments in new flexible resources—generation resources such as energy storage and flexible gas resources as well as new demand-side programs such as load shifting, demand response, and load flexibility—may help to facilitate renewable integration.

This study is designed to highlight the questions and decisions that resource planners must consider as electricity systems evolve under high penetrations of renewable generation.

## 1.4 Organization of Report

The Western Interconnection Flexibility Assessment is an ongoing collaborative effort conducted by E3 and NREL and funded by WECC, WIEB, and the Department of Energy (DOE). As the project is still in progress, this interim report is intended to provide an update on the development of key modeling input data needed for this analysis as well as the methods and results from the first analytical phase of the project, a traditional LOLP assessment of reliability in each region of the Western Interconnection. Once the second phase—the study of operational flexibility under high penetrations of renewable generation—has been completed, this report will be updated with its results. The remainder of the interim report is organized as follows:

- Section 2 provides an overview of the scope of analysis and modeling approach used in this study;
- Section 3 presents the data and methods used in the reliability assessment of the Western Interconnection;
- Section 4 shows the results of the reliability assessment of the 2024 Common Case;
- *Section 5 (forthcoming in July) will present the data and methods used in the flexibility assessment of the Western Interconnection;*
- *Section 6 (forthcoming in July) will present the key results from the flexibility assessment; and*
- *Section 7 (forthcoming in July) will lay out key conclusions of the study.*

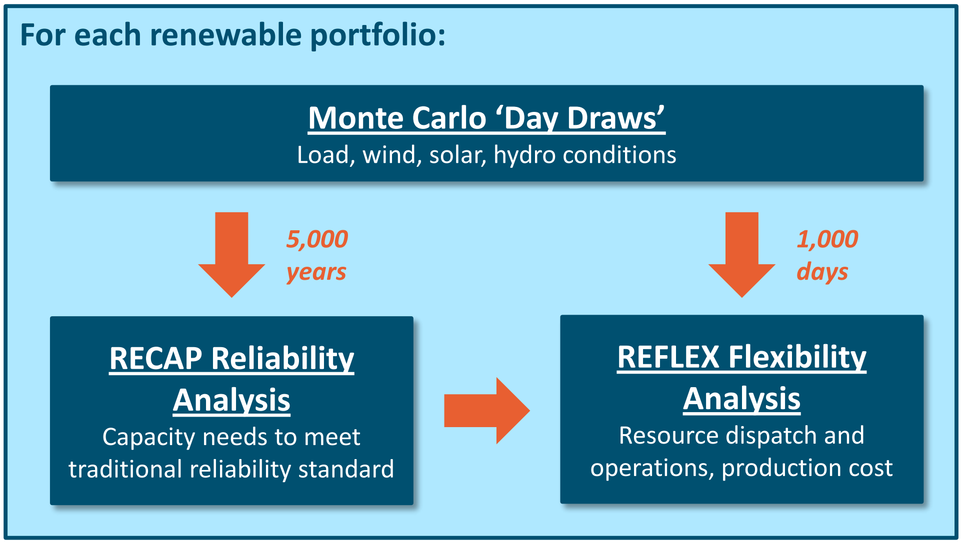
In addition, a Technical Appendix with details on modeling methodology, data development, and detailed assumptions is included as a supplement to this report.

# 2 Modeling Approach

## 2.1 Overview

The framework for the flexibility assessment divides the analysis into two phases, as outlined in Figure 4: first, the resource adequacy of the generation fleet is studied using a traditional loss-of-load probability modeling framework; subsequently, the operations of the system are modeled using an adaptation of traditional production simulation analysis. The two-phase approach to the flexibility assessment is used in order to isolate reliability events that result from a pure shortage of capacity—that is, a system not designed to meet a traditional threshold for reliability—from challenges that may be related to limits on the system's operational flexibility.

**Figure 4. Two phases of analysis in the flexibility assessment framework.**



The first phase of the analysis uses the **Renewable Energy Capacity Planning (RECAP)** model to assess the reliability of the various regions of the Western Interconnection using an industry-standard loss-of-load-probability modeling framework. In order to compare the reliability of a system with a minimum reliability threshold, RECAP uses a probabilistic time sequential model of both loads and resources to simulate thousands of years of possible conditions in the electric sector; examining such a breadth of conditions is needed because reliability events are exceptionally rare. The result of the first phase is an identification of "pure" capacity needed to avoid loss of load that results purely from a shortage of resources.

The second phase uses the **Renewable Energy Flexibility (REFLEX)** model for **PLEXOS for Power Systems**—an adaptation of traditional production simulation—to evaluate the operations of the electric system studied in the first phase. The computational complexity of this question is, by necessity, substantially greater than the reliability analysis of the first phase; production simulation models such as the one used herein use a least-cost unit commitment and dispatch algorithm to minimize the costs of operating an electric system subject to a broad set of constraints. The complexity of the unit commitment problem necessitates the analysis of a reduced set of conditions in comparison to the first phase; instead of simulating thousands of years, operations of the system are simulated for thousands of plausible days in a search for conditions that may challenge the flexibility of the system.

In both of the phases of analysis, this study uses random sampling of weather-correlated load, wind and solar conditions as well as a range of historically-based hydroelectric conditions in order to capture a breadth of plausible system conditions. Each "draw" analyzed in this study—a twenty-four hour period—consists of hourly profiles for load, wind, and solar; as well as a daily budget and operating constraints for hydroelectric generators in the Western system. Because data for these four variables is rarely available over a long and consistent time period, time-synchronous data, which captures the proper correlations, does not typically represent the full distribution of conditions a system may experience. To better represent the distribution of possible system conditions, this study creates a set of random load, wind, solar, and hydro draws by matching the conditions from a large historic library of each while preserving underlying seasonal and weather-related correlations among them.[2] In order to capture as diverse a set of conditions as possible, draws are created from extensive sets of load, wind, solar, and hydro performance data; the extent of each data set used in this study is shown in Figure 5. These datasets serve as the

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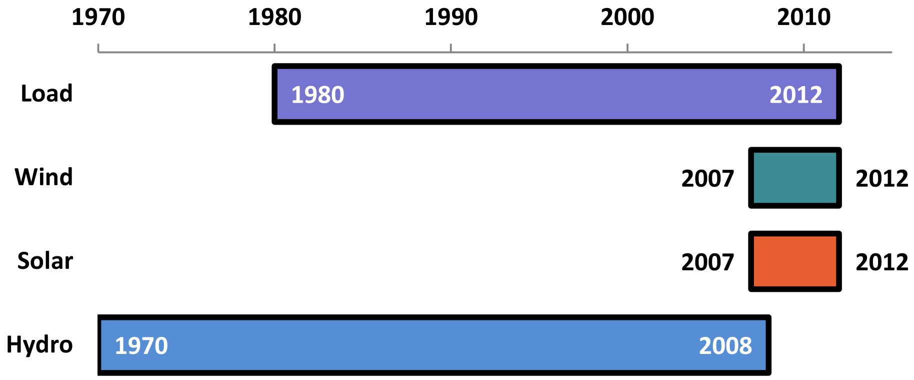
[2] A more detailed description of the methodology used to match load, wind, solar, and hydro draws while preserving key weather-driven and seasonal relationships among them is presented in Section 3.2.3.

backbone for analysis of both resource adequacy and operational flexibility provided herein.

**Figure 5. Historical conditions used to develop load, wind, solar, and hydro data for draws.**



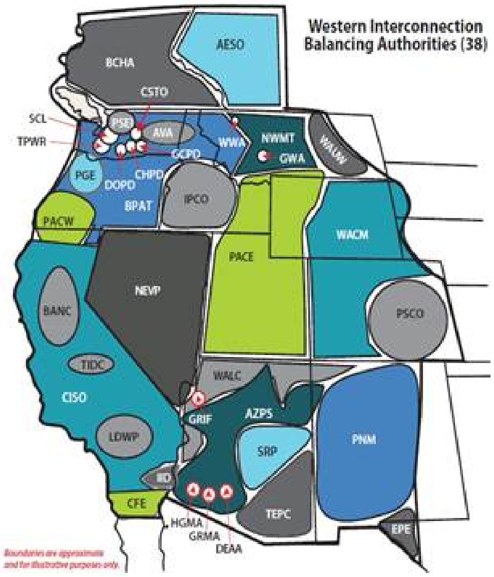
To simulate detailed operations of generators across the Western Interconnection, this study relies heavily on the production simulation platform PLEXOS for Power Systems and the technical constraints on generators developed for the 2024 Common Case. This analysis deviates from the Common Case with respect to the treatment of loads, renewable resources, hydro resources, and transmission constraints, all of which are discussed herein.

## 2.2 Study Scope

### 2.2.1 GEOGRAPHIC SCOPE

The Western Interconnection, shown in Figure 6, is composed of 38 balancing authority areas (BAs), each responsible for ensuring the balance between load and generation within its footprint on an instantaneous basis. This is achieved through the scheduling and dispatch of generation resources, the scheduling of interchange with neighboring balancing authorities, and the reservation of generation capacity to meet ancillary services needs that allow the system to balance subhourly fluctuations and respond to contingencies.

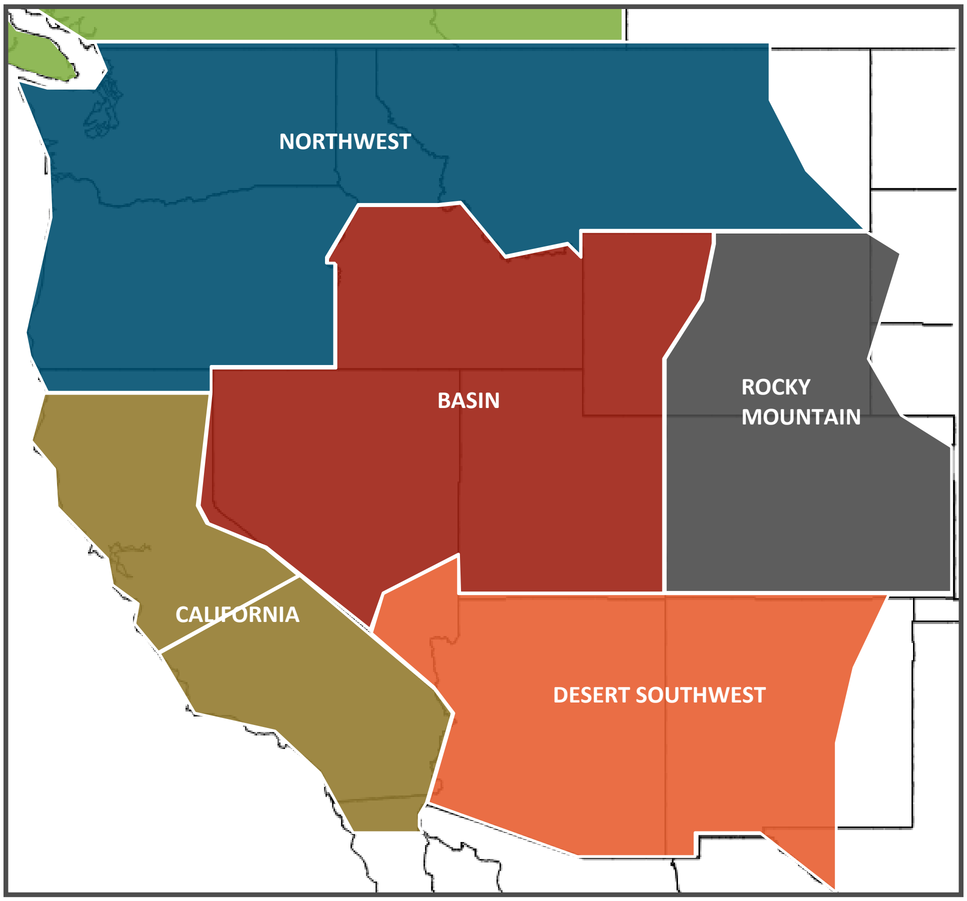
**Figure 6. Balancing authorities of the Western Interconnection.**



While each individual BA is responsible for ensuring the adequacy of its resources to serve load, examination of resource adequacy and operational flexibility at this granular level ignores the interconnectedness of many BAs and the geographic diversity of load and resources that mitigate reliability challenges. Consequently, this study adopts a regional perspective, examining reliability and flexibility in the five regions shown in Figure 7, each representing an aggregation of BAs in the West. The choice of regional boundaries was based on a number of considerations, including:

- **Existing institutional infrastructure supporting coordination in planning and/or operations.** With this study's focus on questions related to flexibility resource planning—and, relatedly, on operations—the regional framework is useful because most of the regions evaluated in this study have some existing degree of coordination in planning and/or operations.
- **Homogeneity of loads and renewable resources.** Across the WECC, there is a high degree of diversity in loads and resources. The boundaries chosen for this study divide the WECC into regions with relatively uniform load patterns—that is, loads with similar seasonal and daily patterns. Similarly, each region is also characterized by its locally available renewable resources and its relative preferences for those resources.
- **Limited major internal transmission constraints.** Regional boundaries are chosen to highlight major existing transmission paths in the WECC that act as conduits for power exchange in the West.
- **Consistency with TEPPC conventions.** The division of the Western Interconnection into the five regions shown in Figure 7 is largely consistent with the groupings of balancing authorities used by TEPPC in modeling resource adequacy and the sharing of reserves in operations.

Figure 7. Five regions of focus for this study.



Through its organization as a collection of regional studies, this study is intended to mimic the perspectives of resource planners in each region seeking to understand future renewable integration challenges while recognizing that the Western system is not centrally and optimally dispatched. While some degree of coordination exists among balancing authorities in today's system, power exchange in the Western Interconnection is generally conducted through long-term contractual arrangements or bilateral agreements rather than through a centralized optimal dispatch of resources. As a result, the ability of the system to integrate higher penetrations of renewables successfully depends not only on the technical capabilities of the generating fleet but on the scheduling practices and conventions of neighboring balancing authorities and regions.

The current practice of bilateral transactions and scheduling of power exchange does not result in least-cost dispatch across the entire interconnection, as is assumed in conventional production simulation modeling. The regional approach taken in this study provides the ability to mimic the “friction” that prevents optimal dispatch in today’s operations. This approach, which allows this study to examine both technical and institutional barriers to renewable integration in the Western Interconnection, distinguishes this study from a number of prior technical analyses of high renewable penetrations that have examined the ability of the Western Interconnection to balance high penetrations of renewable generation as an integrated whole.

Using the regional approach, this study identifies and characterizes challenges that may accompany higher renewable penetrations in each region. “Challenges” may appear in a number of forms, including the need to curtail renewable generation due to oversupply or ramping constraints; substantial changes in the dispatch patterns of coal, gas, and hydro generating resources from their historical utilization; and constraints on interregional power exchange. The degree to which each of these issues may materialize at higher renewable penetrations will vary from one region to another depending on the characteristics of loads and renewable generation as well as the composition of the non-renewable generation fleet. By studying each region individually, this study seeks to highlight both the nature of the integration challenges that each region may face as well as the measures and/or steps that may prove most effective in facilitating renewable integration.

The five regions examined in this study encompass the U.S. portion of the Western Interconnection. Exclusion of the AESO, BC Hydro, and CFE BAs is due to the dearth of publicly available operational data with which future flexibility issues in each of these jurisdictions may be examined; however, the approach and techniques used in this assessment could be applied just as validly to each of these areas if such data becomes available.

### 2.2.2 RENEWABLE PORTFOLIOS

This analysis examines reliability and the need for flexibility for two future possible portfolios of renewable resources in the Western Interconnection:

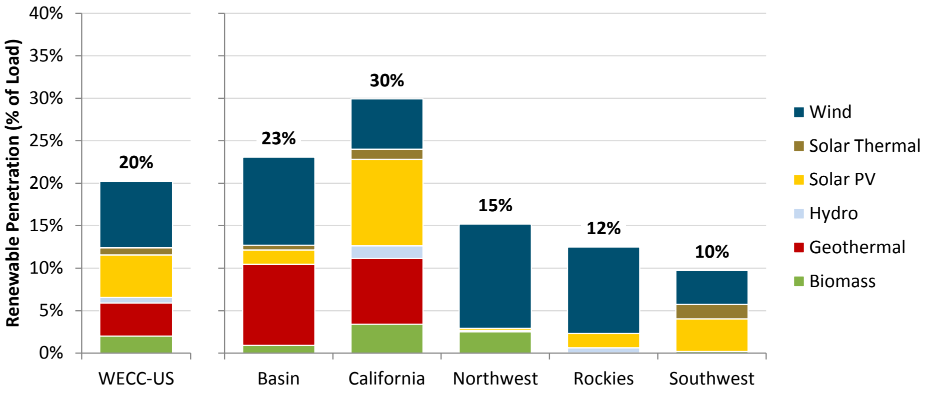
- A **Base Case**, which reflects current state RPS targets as captured in WECC's 2024 Common Case; and
- A **High Renewables Case**, which includes additional wind and solar generation throughout the footprint of the WECC in excess of current policy goals.

Each portfolio contains a geographically and technologically diverse set of renewable resources intended to represent a plausible future for renewable development in the Western Interconnection.

#### *2.2.2.1 Base Case*

The Base Case analyzes in this study reflects current state renewable portfolio standard (RPS) goals as captured in WECC's 2024 Common Case. The assumptions of future renewable development in accordance with these policies were specified by TEPPC with input from stakeholders during the development of the 2024 Common Case. Across the study footprint, renewable generation serves approximately 20% of load in the Common Case. The mix of renewable resources in each region, expressed as a percentage of total electric load, is shown in Figure 8.[3]

**Figure 8. Renewable penetrations studied in the Base Case (based on TEPPC's 2024 Common Case).**



### 2.2.2.2 *High Renewables Case*

In addition to the Base Case, this study explores flexibility challenges and integration strategies for a High Renewables Case developed specifically for

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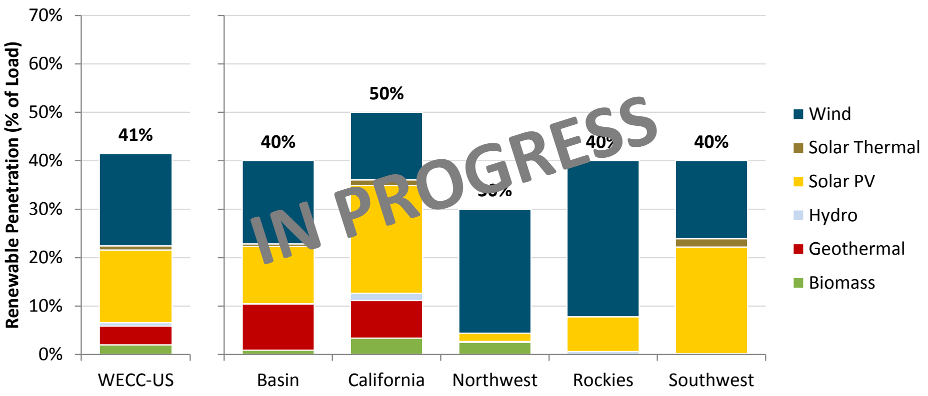
[3] In reporting the penetration of renewable generation, this study uses the convention of calculating the combined penetration of behind-the-meter and wholesale renewable generation as a percentage of total load at the transmission level. It therefore differs from the accounting used in most state renewable portfolio standards in three respects: (1) behind-the-meter solar PV is included in the renewable penetration; (2) the penetration is expressed as a percentage of load a the transmission level rather than at the customer meter; and (3) it does not account for the contractual entitlement of loads in one region to renewable generation in another based on existing long-term contracts (e.g. wind generation in the Columbia River Gorge under contract to utilities in California is shown in the Northwest, not in California).

analysis in the Flexibility Assessment. The mix and penetration of renewable resources in each region in the High Renewables Case is shown in Figure 9.[4]

**Figure 9. Renewable resources included in the High Renewables Case.**



In its choice of renewable portfolios for study in the High Renewables Case, this study seeks to examine a level of penetration that will present challenges to the flexibility of the system. Each region's portfolio is chosen to examine a pressing question related to the interaction between increased renewable penetration and the region's existing resources. In regions with relatively high penetrations of solar (Basin, California, and Southwest), the primary question investigated in this study is the extent to which the non-renewable fleet in each region can accommodate the large concentration of solar generation during the middle of the day. In regions with high wind penetrations (Northwest and Rocky Mountains), the motivating question is how the hour-to-hour, day-to-day, and

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[4] At the time of this interim report, the composition of the renewable portfolios to be studied in the High Renewables Case is still under development. What is shown of the High Renewables Case in this report reflects the study team's initial plan for modeling the flexibility needs of the High Renewables Case.

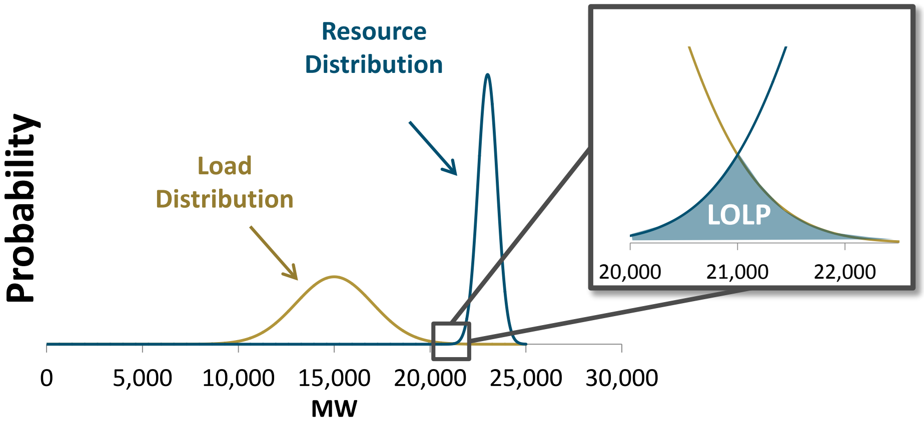
season-to-season variability (and associated forecast uncertainty) of the wind generation may be balanced by non-renewable resources.

## 2.3 Phase 1: Resource Adequacy Assessment

### 2.3.1 HISTORICAL APPROACH TO RELIABILITY PLANNING

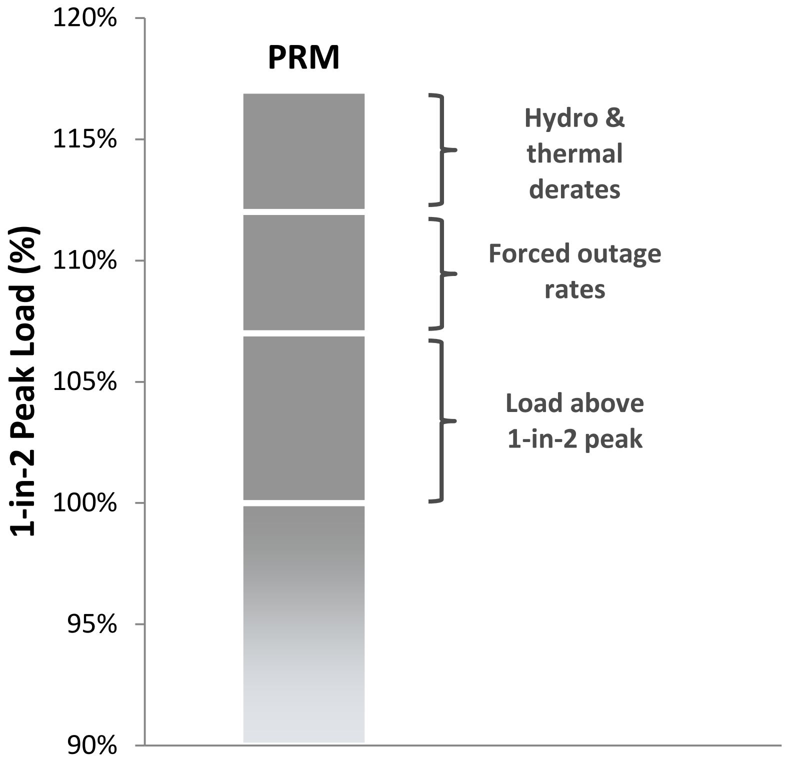
Reliability modeling has a long history in electric sector resource planning. Loss-of-load-probability (LOLP) modeling, a modeling framework in which the availability of generation resources is compared against potential system load across a broad range of possible conditions, has been established as the industry standard. Because tolerance for loss of load due to generation inadequacy is typically very low—a common standard is "one day in ten years"—such an approach is necessary to capture the tails of the distribution during which loss of load may occur (see Figure 10).

**Figure 10. Loss of load probability modeling framework.**



Because of the computational complexity of loss-of-load-probability modeling, planners commonly use a “planning reserve margin” (PRM) target as a simpler benchmark for generation adequacy. Traditionally, a system’s PRM has been defined as the amount of nameplate generation capacity (including available imports) in excess of the system’s expected 1-in-2 peak demand; many utilities and generation planners have established PRM targets of 13-17%. The reserve margin above the 1-in-2 peak demand may be understood as the additional capacity needed to ensure reliability while accounting for a number of inherently uncertain factors in an electric system, including variations in annual peak demand from the forecast 1-in-2 peak, forced outages of generators and/or transmission lines, and thermal derates of generation capacity. While the PRM target itself should be derived through loss-of-load-probability modeling, these factors can be understood as the “building blocks” that contribute to the need to hold a reserve margin above the 1-in-2 peak, as illustrated in Figure 11.

**Figure 11. Planning reserve margin "building blocks"**



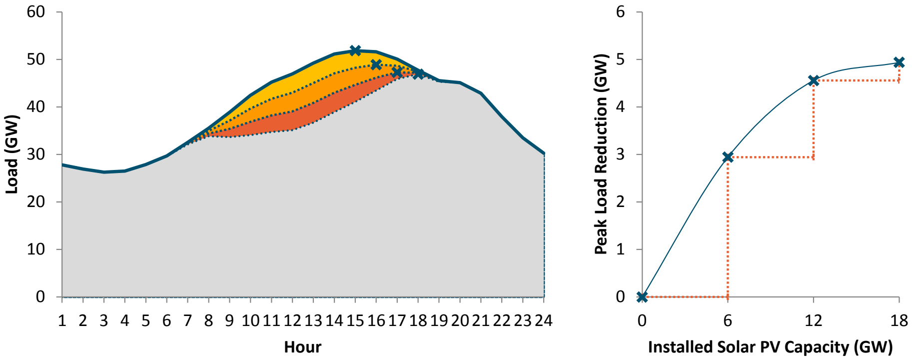
## 2.3.2 RELIABILITY PLANNING WITH VARIABLE GENERATION

The simple planning reserve margin framework has proven adequate for reliability planning when most of the capacity in a system is dispatchable and can be called on to serve loads during times of peak; however, with the addition of increasing amounts of variable generation from wind & solar technologies in many areas in the Western Interconnection, the simple conventions of the planning reserve margin are challenged. Because such resources cannot be controlled by the operator and often produce at levels below their nameplate capacity during times of peak load, variable generation technologies do not contribute the same amount of reliable capacity to a system as dispatchable generators.

Across the Western Interconnection, planners have taken a variety of approaches to adapt the simple PRM framework for continued use with increasing penetrations of variable generation. The most common approach has been to develop rules of thumb by which the nameplate capacity of wind and solar resources may be adjusted in the calculation of the PRM to reflect their limited contributions to system reliability; such adjustments are commonly derived through an analysis of historical and/or simulated output during peak load periods. This approach typically yields multipliers of 40-70% for solar technologies and 5-30% for wind technologies, and values in this range are currently used in many reliability planning exercises across the Western Interconnection.

While this rule-of-thumb approach may provide a reasonable approximation of the reliable capacity for variable generation at low penetrations, it fails to capture the impact of variable generation on the timing of the net peak: increasing penetrations of variable generation will cause the timing of the net peak to change, a concept illustrated in Figure 12 for increasing penetrations of solar PV. As the net peak shifts away from periods in which output from variable resources is relatively concentrated to periods in which it is less concentrated, the marginal contribution of those variable resources is reduced, resulting in declining returns to scale with each renewable technology.

**Figure 12. Illustrative reduction of peak load impact of increasing penetrations of solar PV.**



Incorporating this effect into the assessment of system reliability is made possible by a return to the original loss-of-load probability modeling framework, from which a measure of the "effective load carrying capability" (ELCC) of variable generation may be derived.[5] In the context of LOLP modeling, ELCC is defined as the additional firm load that can be met by an additional generation resource while maintaining the same level of reliability as the base system. Notably, ELCC captures the interactive effects between renewable generators as penetrations increase, and is a suitable measure of capacity for use in traditional planning reserve margin calculations. Robust generation adequacy planning under high penetrations of variable generation therefore requires a reestablishment of the linkage between the conventions used in the planning reserve margin framework and the underlying stochastic reliability modeling through which those conventions were originally derived.

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[5] Garver, L.L., "Effective Load Carrying Capability of Generating Units," Power Apparatus and Systems, IEEE Transactions on , vol.PAS-85, no.8, pp.910,919, Aug. 1966 http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=4073133&isnumber=4073117

### 2.3.3 RECAP MODELING FRAMEWORK

In order to provide a platform for the reliability analysis of electric systems with high penetrations of renewable generation, E3 developed the **Renewable Energy Capacity Planning (RECAP)** model, a stochastic loss-of-load-probability model that uses datasets of load, wind, and solar conditions to provide a forward-looking assessment of system reliability. The RECAP model relies on industry standard methods for assessing power system reliability[6,7] with additional features that allow it to make better use of often limited datasets for wind and solar (see Section 3.2.3 on draw methodology). The RECAP model simulates years by randomly sampling loads, renewables, monthly hydroelectric energy budgets, generator outages and maintenance. Outage conditions occur when load exceeds the sum of available supply resources, also accounting for operating reserves.[8]

As already noted, the conditions under which loss of load occurs are exceedingly rare and it becomes necessary to analyze a large number of Monte Carlo draws before reliability statistics converge. This study simulates plausible combinations of load and resources across 5,000 years, to produce the metrics intended to help inform reliability planning. Key probabilistic outputs from the RECAP model, each of which depends on the characteristics of loads and generation fleet, include:

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[6] R. Billinton and R. N. Allan, Reliability Evaluation of Power Systems, Second ed. New York: Plenum Press, 1996.

[7] R. Billinton and W. Li, Reliability Assessment of Electric Power Systems Using Monte Carlo Methods. New York: Plenum Press, 1994.

[8] Operating and contingency reserves are often ignored in LOLP modeling and are not included in results for this report except where explicitly stated

- **Loss of load frequency (LOLF):** the expected frequency of reliability events.
- **Loss of load expectation (LOLE):** the number of hours of expected lost load.
- **Expected unserved energy (EUE):** the amount of load that is unserved during reliability events.
- **Normalized expected unserved energy (EUE-Norm):** Expected unserved energy divided by the sum of annual load.

In this study, the “1-in-10” standard is interpreted to mean an average of one loss of load event every ten years, alternatively stated as a loss of load frequency of 0.1. Among the common interpretations, this is the most stringent[9] metric for gauging reliability; the use of a conservative standard helps to ensure that reliability challenges identified in the flexibility assessment may be attributed to a lack of flexibility rather than a lack of capacity.

A second element of core functionality is the capability to calculate the **effective load carrying capability (ELCC)** of a resource (or portfolio thereof), a measure of its contribution to system reliability, expressed in terms of firm megawatts of demand served. This type of metric is particularly useful for reliability planning with high penetrations of variable resources, as it provides a rigorous analytical foundation with which to measure the contribution of variable energy resources to system reliability in the context of a traditional planning reserve margin calculation.

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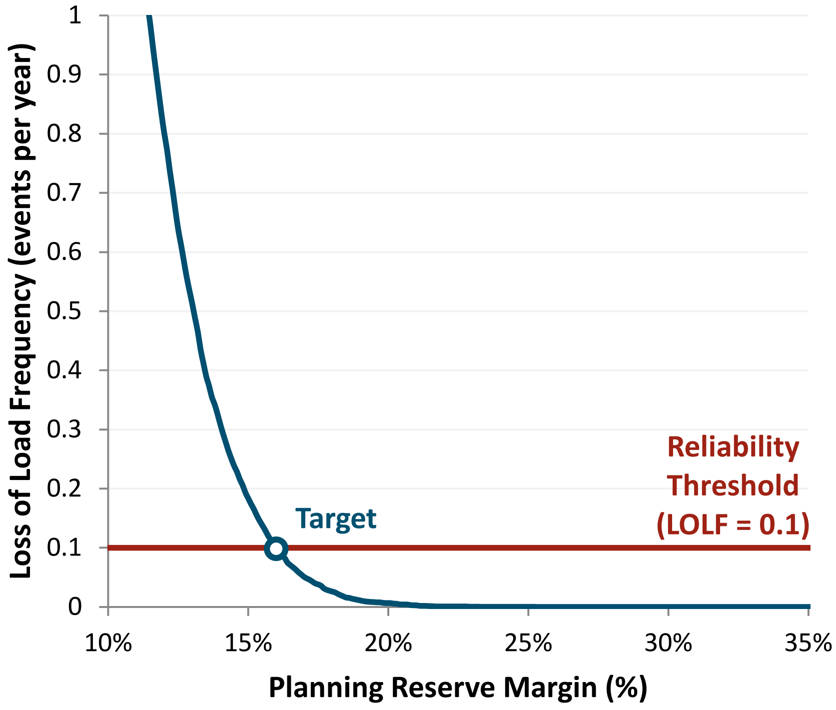
[9] The Brattle Group & Astrape Consulting, *Resource Adequacy Requirements: Reliability and Economic Implications*. Available at: http://www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf

Third, RECAP evaluates the **planning reserve margin** of the system in order to establish the link between the loss-of-load-probability analysis and the simpler conventions that have become common practice. The calculation of a planning reserve margin allows RECAP not only to link the reliability of a given system to its current planning reserve margin, but to derive each system's target PRM based on a loss-of-load-frequency threshold of one event in ten years. The target PRM represents the minimum planning reserve margin for a system for a system to adhere to acceptable standards of system reliability.

The functional relationship between the stochastically derived loss-of-load frequency and the simpler planning reserve margin is shown in Figure 13. The shape of the curve that defines the relationship between LOLF and PRM will reflect the characteristics of the electric system analyzed; the curve itself and the resulting target planning reserve margin depend on such factors as the size (and amount of diversity) in the system, the inter-annual variability in weather conditions, and the probabilities of forced outages on individual generators.

Figure 13. Illustration of relationship between loss of load frequency and planning reserve margin



## 2.4 Phase 2: Flexibility Assessment

### 2.4.1 BACKGROUND

Flexibility analysis has a much shorter history than capacity-based reliability analysis, as it has only become a relevant question in resource planning in the context of higher renewable penetrations in recent years. Because of this relatively short history, there is currently no industry-standard methodology for assessing the flexibility of a power system. One of the goals of this study is therefore to investigate the key drivers of the need for flexibility in an electricity system and to identify critical modeling considerations in flexibility planning analyses going forward.

The approach used in this study builds on production simulation modeling. Production simulation models, which simulate the optimal dispatch of an electric system subject to a set of constraints, are commonly used to model the operations of electric systems. Such models are employed across a diverse range of applications and types of analyses, including transmission planning studies, renewable integration studies, asset valuation exercises, market price forecasts, and integrated resource plans. Depending on the purpose of the modeling exercise, production simulation models can produce a range of different outputs, including flows on transmission lines, operating behavior of individual power plants, and market prices for energy and ancillary services over various timescales and at different locations on an electric system.

The computational complexity of production simulation models typically far exceeds that of loss-of-load-probability modeling; while the latter simply compares total available generation capacity against load, the former provides a least-cost solution for how those resources should be optimally dispatched subject to a large number of additional constraints. The types of constraints imposed on production simulation models—which include such parameters as technical constraints on the operations of individual power plants, the need for individual entities to hold operating reserves in addition to meeting load, and a representation of the underlying transmission network—may range in their complexity depending on the particular application of the model. The computational complexity of the simulation depends on the level of detail included with respect to each of these classes of constraints and on the chronological extent of the simulation (e.g. one day versus several years). With today's computational resources, full representation of all possible constraints over a wide range of conditions is not yet practical. Accordingly, the level of detail is often tailored to the underlying purpose of the particular application in order to focus on key outputs while allowing for simplifications with respect to less important constraints. For example:

- TEPPC's annual transmission planning studies, which study future flows on transmission lines in the West under a variety of future scenarios, include a full representation of the high-voltage transmission network of the Western Interconnection—over 25,000 nodes are included in a nodal transmission network—but makes simplifications in the unit commitment logic used to dispatch generators.
- NREL's Western Wind and Solar Integration Study, which studied the impact of high penetrations of variable generation on the integrated Western Interconnection, used a multi-stage unit commitment model as well as a five-minute real-time dispatch of generation resources but used a simplified zonal representation of the transmission network.

In order to facilitate effective planning for flexibility, the modeling approach used should prioritize detail with respect to the key constraints on a system that might limit its operational flexibility.

### 2.4.2 REFLEX MODELING FRAMEWORK

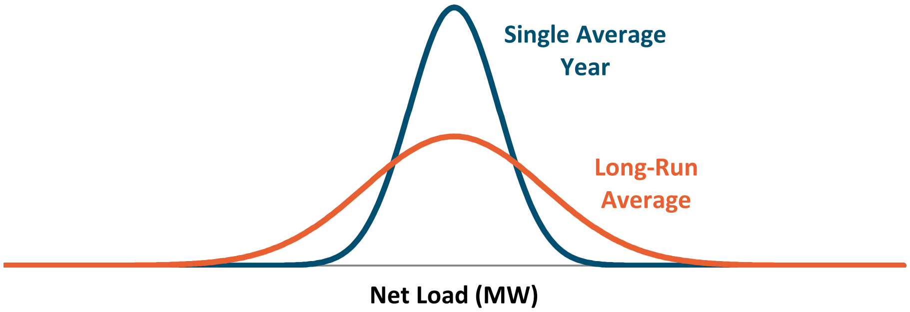
This study uses the **Renewable Energy Flexibility (REFLEX) model** for **PLEXOS for Power Systems**, an application of production simulation modeling that has been tailored specifically to use in the context of informing flexibility planning decisions. While much of the data and substantial portions of the modeling approach utilized in this study can be and has been used for operations modeling, the approach taken for this analysis is differentiated from an operational study that seeks to predict how a system may operate under higher penetrations of renewables. This study instead seeks to understand more specifically how a planner might use simulated operational information to inform a flexibility planning decision. In this planning context some operational and institutional constraints are designed not to predict how a system may operate, but are instead designed to address, in an analogous way to reliability planning, the extent to which a planner chooses to reliably count on a resource or transaction to alleviate potential flexibility challenges in the future. To address these questions, E3 has developed the REFLEX production simulation modeling framework, which is implemented within PLEXOS for Power Systems.

With its off-the-shelf modeling capabilities, PLEXOS for Power Systems provides a strong foundation for the assessment of generation flexibility. PLEXOS enables the use of a multistage unit commitment and dispatch simulation—used to model day-ahead and hour-ahead commitment cycles as well as an actual hourly dispatch—to capture the effects of scheduling based on imperfect forecasts on operations as well as the differing behaviors of inflexible units with longer start-up times. In addition, PLEXOS allows for cooptimization of energy and ancillary services dispatch, ensuring that the dispatch of units on the system reflects the need to hold operating reserves to accommodate the subhourly variability and forecast uncertainty of load, wind, and solar generation.

Building on the native capabilities of PLEXOS, the REFLEX modeling framework seeks to address three key planning questions:

- **How often is the system expected to encounter flexibility constraints?** This requires simulation of a more complete collection of system conditions than are typically encountered in a single year (the standard study period for production simulation analyses). The REFLEX approach addresses this need by combining the stochastic framework of reliability modeling with the analytical rigor of production simulation modeling to provide a view of plausible operating patterns and needs across a broad range of conditions, incorporating the full possible distribution of conditions on the electric system (Figure 14). In this study, the same probabilistic draw approach used to generate plausible days of conditions for the capacity analysis is used to create inputs for REFLEX, allowing for statistical analysis of the observed operational challenges.

Figure 14. Difference between studying a single year and a long-run distribution.

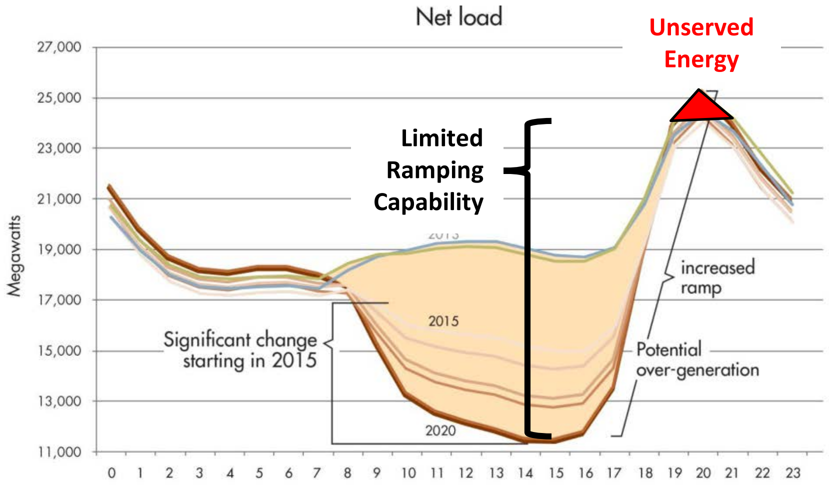


- **How responsive should the planner assume that the system's resources will be in the event that operations become flexibility constrained?** Flexibility is limited on an electricity system by two classes of constraints: technical constraints related to the operating limits of the generators on the system and institutional constraints related to the ability of the system to respond to fluctuations in both load and generation given the limitations of market structures, information transfer, and bilateral arrangements. Just as today's system planner may determine a reliable level of imports from other systems to count toward a planning reserve margin, planners considering flexibility constraints may also need to decide how much flexibility to assume can be provided by neighboring balancing areas during flexibility constrained periods. A planner may conservatively assume that less flexibility is available from resources outside the footprint of the system than they can technically provide in order to ensure that internal flexibility challenges can be mitigated in the long term even if procurement plans or operational paradigms change in the neighboring systems.

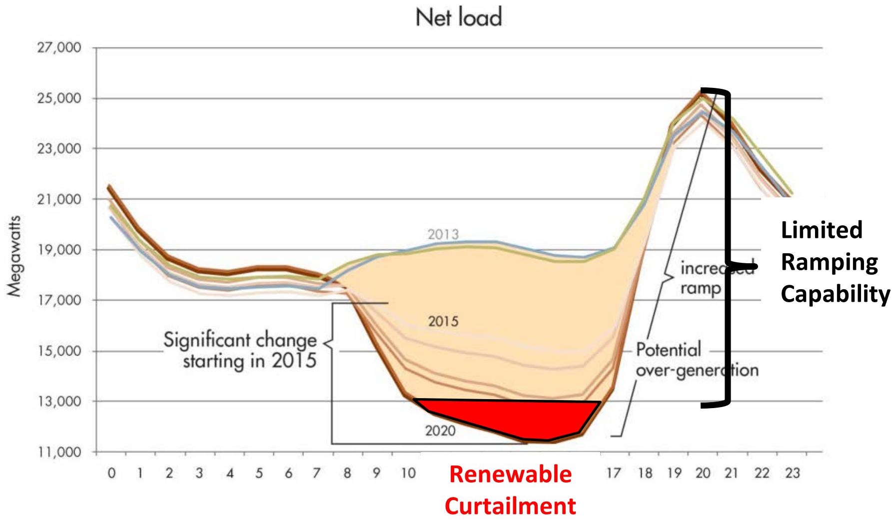
- **To what extent is the system operator (on behalf of the ratepayers) willing to accept the consequences of inadequate resource flexibility?** In traditional reliability analysis, the consequence of inadequate capacity is relatively straightforward: the system is incapable of simultaneously meeting all loads, so some loads are shed. Inadequate flexibility may also lead to loss of load, if for example a large portion of the thermal fleet is cycled off to accommodate renewable resource generation that then experiences a rapid downward ramp that cannot be met with the limited available upward ramping capability (this is illustrated in Figure 15a). However, given that operators are overwhelmingly concerned with reliability, a more likely (and more economic) scenario is that the system operator would curtail some portion of the renewable energy to ensure that the thermal resources required to maintain reliability can remain online (Figure 15b). In this way renewable curtailment is both a key operational strategy in flexibility-constrained systems and is the primary consequence of inadequate flexibility (the analogue to loss-of-load in a traditional reliability analysis). The extent to which renewable curtailment is utilized in a flexibility planning analysis will depend on its assumed cost. This study analyzes the economic tradeoff between using renewable curtailment to provide operational flexibility versus relying on flexible thermal resources by testing sensitivities on the renewable curtailment cost penalty.

**Figure 15. Illustration of the operational tradeoff between unserved energy & renewable curtailment.**

**(a) Limited ramping capability resulting in unserved energy**



**(b) Limited ramping capability resulting in renewable curtailment**



The REFLEX analysis yields a number of metrics and outputs to help characterize flexibility planning challenges, including:

- **Distributions** of the hourly net load, hourly net load ramps, and net load ramps over longer durations (2-hour, 3-hour, etc.);
- **Annual expected values** of oversupply (which must be mitigated with either renewable curtailment or spilling hydropower), annual production cost, and annual $CO_2$ emissions; and
- **Month-hour expected values** of the above metrics and of operating reserve provisions and violations to illuminate seasonal and diurnal trends and to identify periods with the greatest flexibility challenges.

In addition to these probabilistic metrics, the REFLEX approach provides useful snapshots of challenging operating days that highlight the impacts of variable renewables on net load and the dispatch of available resources to meet the need for flexibility.

REFLEX provides a framework in which the effectiveness of new investments in enabling renewable integration may be tested: “in-and-out” cases allow for the identification of promising (high-value) integration solutions. A scenario can be tested, for example, with and without a new technology like energy storage. The difference in the expected annual cost (including production costs, curtailment cost, and fixed costs of any solutions) between the cases will determine if the new technology provides a cost-effective approach to mitigating integration challenges. The cost effectiveness of integration solutions will depend on a number of exogenous factors, including the level of coordination between planning entities across the West. If each region plans to mitigate its own renewable integration challenges without (or with limited) reliance on its neighbors, then integration challenges within each region will likely be greater and integration solutions will be more cost effective than in a scenario in which regional planners coordinate to take advantage of potential complementarity between regional load and renewable supply imbalances.

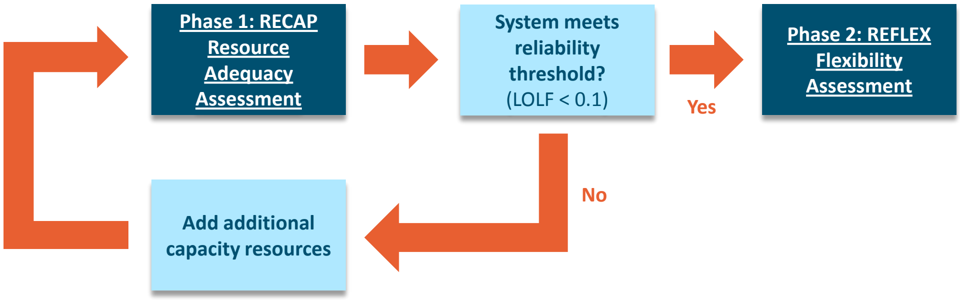
The REFLEX model, through its focus on these key drivers of the need for flexibility and the related physical and institutional constraints, provides a platform upon which to study the potential realization of integration challenges at high penetrations of renewable generation. This study uses this platform to explore the possible magnitude and frequency of such challenges under a specific set of renewable portfolio assumptions, as well as potential steps that might be taken to relieve those challenges, in order to identify barriers and opportunities for renewable integration in the Western Interconnection.

# 3 Phase 1: Data & Methods

## 3.1 Overview of Approach

In order to assess the resource adequacy of the electric system in each region, RECAP compares simulated loads and available generation resources stochastically across thousands of years of potential combinations of conditions, accounting for the variability of load, renewable output and hydro conditions, as well as the risk of outages of traditionally dispatchable generators. The reliability of each system is measured against a threshold of one reliability event in ten years: if, across the thousands of years simulated, the loss-of-load frequency exceeds one day in ten years (LOLF > 0.1), the system's reliability is deemed insufficient, and capacity must be added to match the deficit identified. This is a crucial and natural prerequisite for the flexibility assessment, as it ensures that any challenges that arise in the operational modeling can be attributed to a lack of flexibility and are not simply a result of a need for "pure" capacity. This framework is illustrated in Figure 16.

Figure 16. Role of RECAP reliability assessment in the study.



The data inputs needed for such a resource adequacy assessment, shown in Table 1, are derived from the 2024 Common Case where possible; however, additional data sets are incorporated into the analysis as needed to improve the characterization of various key inputs. This section describes each of the categories of input data and the sources and assumptions used in the resource adequacy assessment.

Table 1. Key data needs for resource adequacy assessment

| Category | Detail | Data Needs |
|---|---|---|
| **Load** | | • Hourly profiles for multiple years |
| **Variable Renewable Generation** | • Solar PV<br>• Solar Thermal<br>• Wind | • Hourly profiles for multiple years |
| **Conventional Generators** | • Nuclear<br>• Coal<br>• Gas<br>• Biomass<br>• Geothermal | • Maximum output by month (MW)<br>• Forced outage rates (%) |
| **Hydro** | • Conventional Hydro<br>• Small Hydro | • Hydro conditions for multiple years<br>• Sustained peaking capability of hydro fleet under various hydro conditions |
| **Imports/Exports** | • Specified<br>• Unspecified | • Availability of imports during peak<br>• Obligations to export during peak |

## 3.2 Load, Wind, and Solar Inputs

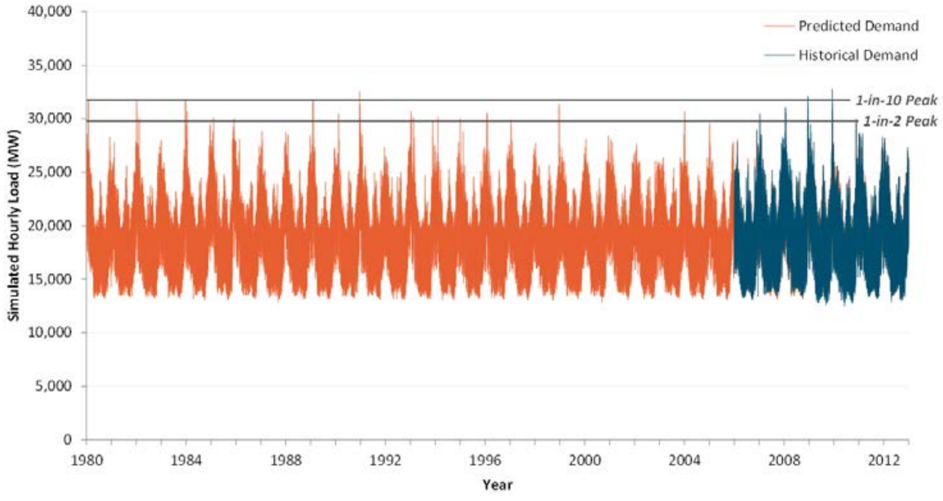
The stochastic framework used by the RECAP model requires a robust characterization of possible load and renewable conditions. In order to represent the distribution of possible conditions, this study uses a stratified sampling methodology from multiple years of asynchronous load and renewable data to create “draws” of individual days. This section describes:

- How historical hourly profiles are developed for load, wind, and solar resources; and
- How individual day “draws” are created for both reliability and flexibility assessment using a stratified sampling methodology from each data set.

### 3.2.1 LOAD PROFILES

This analysis uses simulated load profiles that reflect expected patterns in hourly load from 1980 to 2012 given the weather conditions experienced over this period. These profiles are create using a neural network regression that links load with daily weather indicators, using the observed relationship between the two from the period 2005-2012 to simulate load shapes consistent with the 2024 Common Case for each weather year between 1980 and 2012 and for each of the load areas modeled in the Common Case. Figure 17 shows an example of the hourly shape simulated for the aggregation of load areas in the Northwest. The methodology used to simulate load shapes is further described in Section 8.1.

**Figure 17. Simulated hourly load shapes for the Pacific Northwest, 1980-2012.**



This approach provides a rich dataset for both reliability and flexibility modeling that captures a wide range of possible weather—and resulting load—conditions. This approach is particularly useful in the stochastic assessment of resource adequacy, as the longer historical record establishes a probability distribution for extreme load events that can contribute to the risk of loss of load.

### 3.2.2 WIND & SOLAR PROFILES

The renewable portfolios studied in Base Case and High Renewables Case amount to penetrations of 20% and 42% of annual load across the study footprint, respectively. In both scenarios, a small share of this total—7% of load—is supplied by various biomass, geothermal, and small hydro resources; the remaining balance is supplied by variable and uncertain wind & solar resources. In the Common Case, shown in Table 2, wind and solar resources account for 13% of load. In the High Renewables Case, shown in Table 3, penetration of wind and solar is increased by a factor between two and three in each region.

**Table 2. Wind & solar resources in the 2024 Common Case (GWh).**

| Technology | | Basin | California | Northwest | Rockies | Southwest |
|---|---|---|---|---|---|---|
| Solar PV | Fixed Tilt | 989 | 15,128 | 62 | 187 | 3,385 |
| | Tracking | - | 7,912 | - | 12 | 1,180 |
| | Rooftop | 351 | 8,257 | 326 | 1,027 | 3,217 |
| Solar Thermal | No Storage | - | 1,597 | - | - | 1,140 |
| | Storage | 440 | 2,189 | - | - | 1,659 |
| Wind | | 8,143 | 18,474 | 23,805 | 7,478 | 6,451 |
| **Total** | | **9,922** | **53,558** | **24,194** | **8,705** | **17,032** |
| *Total (% of load)* | | *12%* | *16%* | *13%* | *12%* | *10%* |

**Table 3. Wind & solar resources in the High Renewables Case (GWh).**

| Technology | | Basin | California | Northwest | Rockies | Southwest |
|---|---|---|---|---|---|---|
| Solar PV | Fixed Tilt | | | | | |
| | Tracking | | | | | |
| | Rooftop | | | | | |
| Solar Thermal | No Storage | | | | | |
| | Storage | | | | | |
| Wind | | | | | | |
| **Total** | | | | | | |
| *Total (% of load)* | | | | | | |

To represent the variable and uncertain output of these resources, this study uses several data sources to develop hourly profiles for the output of wind and solar resources throughout the Western Interconnection across multiple years:

- Wind profiles are from NREL's **Wind Integration National Dataset (WIND) Toolkit**, which provides five-minute simulated wind profiles for

126,000 sites across the continental United States for the period 2007-2013.[10]

- Solar PV profiles are from NREL's **Solar Integration National Dataset (SIND) Toolkit**, which provides 30-minute simulated profiles for both distributed and utility-scale solar PV installations for the period 2007-2013.
- Solar thermal profiles are simulated using NREL's **System Advisor Model (SAM)**. The input files used in the simulation are from the same dataset used to generate the solar PV profiles in the SIND Toolkit.

This study uses a subset of the profiles available in these datasets in order to represent the renewable resources of the Common Case and the High Renewables Case. The profiles used in this study are selected from the original datasets based on geographic location and technology configuration. The geographic locations of wind and solar resources in the Common Case—shown in Figure 18—are based on information provided by WECC, supplemented with data obtained from the Energy Information Administration (EIA) for existing facilities. The additional profiles needed to reflect the incremental resources of the High Renewables Case are selected in each region from the remaining high-quality resource sites in each data set.

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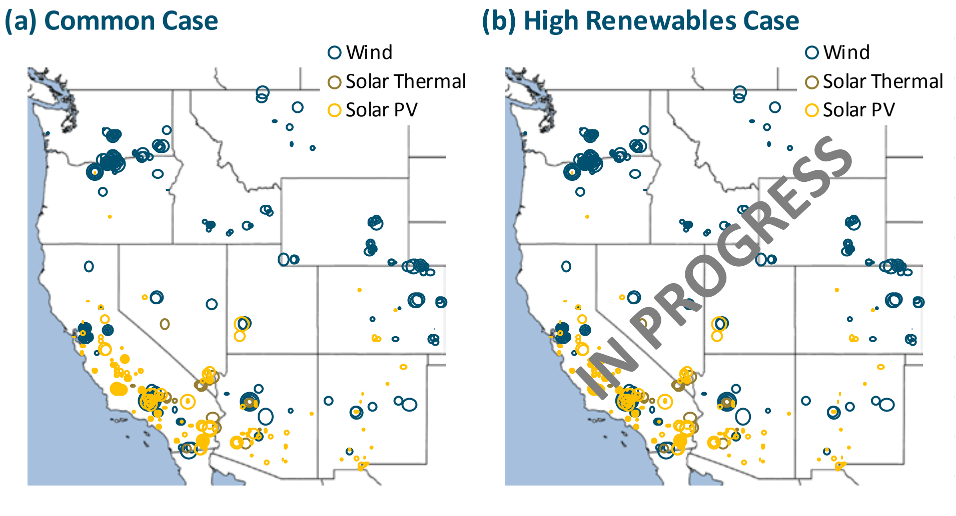
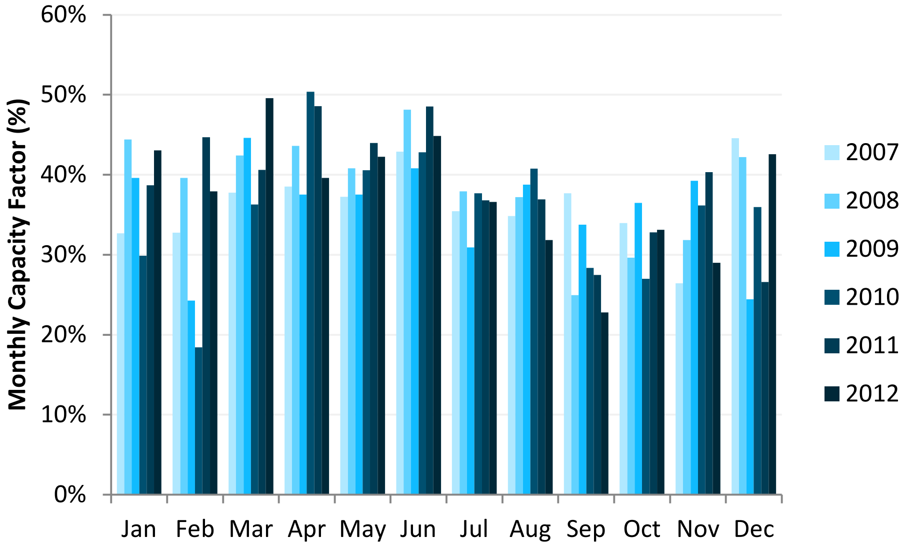
[10] While each dataset covers the historical period 2007-2013, this study uses the profiles from 2007-2012 because of the availability of time-synchronous load data

Figure 18. Common Case wind & solar resources.



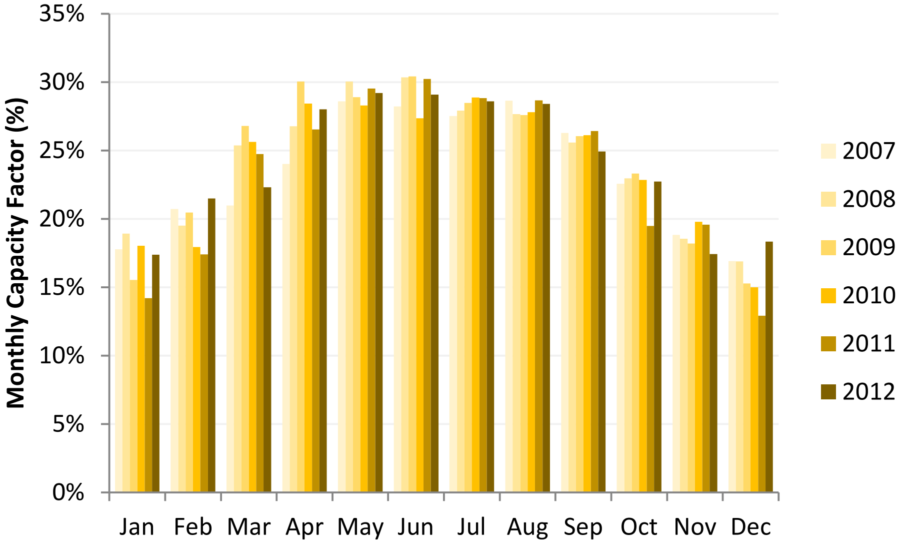
The use of six years of simulated renewable data allows the reliability assessment to capture the inter-annual variability in the expected output of renewable resources. This characteristic is particularly important for a robust representation of the output of wind resources, whose capacity factor can vary considerably from one year to the next. Figure 19, which shows the monthly capacity factors for the profiles used to represent the Common Case wind resources in the Northwest, illustrates this phenomenon.

Figure 19. Monthly average capacity factor for Common Case wind resources in the Northwest, 2007-2012 weather conditions.



Variability in output from one year to the next is less apparent for solar generation; Figure 20 shows the average monthly capacity factor for Common Case solar PV facilities in California. Nonetheless, the length of the simulated record available (2007-2012) helps to create a better distribution of possible solar production conditions and is also useful in characterizing the relationship between load and renewable output.

Figure 20. Monthly average capacity factor for Common Case solar PV resources in California, 2007-2012 weather conditions.



### 3.2.3 DRAW METHODOLOGY

In order to make use of asynchronous datasets of load and renewable profiles, this study uses a stratified sampling methodology to create "draws"—twenty-four hour pairings of load and renewable outputs—for analysis. The sampling methodology, which pairs shapes based on season and type of day, is designed to preserve observed relationships between load and renewable output both across and within seasons to ensure that each draw reflects a plausible combination of load and renewables.

A four-step process is used to construct each draw:

- Select a day from the historical record of load conditions at random. The same historical day is used for each region in order to preserve observed relationships between the regional loads.
- In each region, identify the “day-type” for the historical day drawn. For each month, the “day-type” is defined by the level of daily load relative to the entire historical record of daily load conditions for that month. This study uses fourteen day-types based on percentiles of daily load level, defined in Table 4.

**Table 4. Day-type bins, defined by percentile of daily loads within each month.**

| Bin | Percentile | Load Level |
|---|---|---|
| **1** | <1% | Lowest |
| **2** | 1-3% | Low |
| **3** | 3-6% | Low |
| **4** | 6-12% | Low |
| **5** | 12-20% | Med-Low |
| **6** | 20-30% | Med-Low |
| **7** | 30-50% | Med |
| **8** | 50-70% | Med |
| **9** | 70-80% | Med-High |
| **10** | 80-88% | Med-High |
| **11** | 88-94% | High |
| **12** | 94-97% | High |
| **13** | 97-99% | High |
| **14** | >99% | Highest |

- In each region, select a daily wind profile at random from the appropriate month and day-type bin. Daily profiles are selected independently in each region to match the corresponding day-type conditions.
- In each region, select a daily solar profile at random from the appropriate month and day-type bin. As with wind, profiles are selected

independently in each region to match the corresponding day-type conditions.

The result of this process is a synthetic day-long record of load, wind, and solar profiles across the entirety of the study footprint that captures the key relationships among these variables in each region. The four steps of this process are illustrated in Figure 21.

**Figure 21. Illustration of draw methodology.**

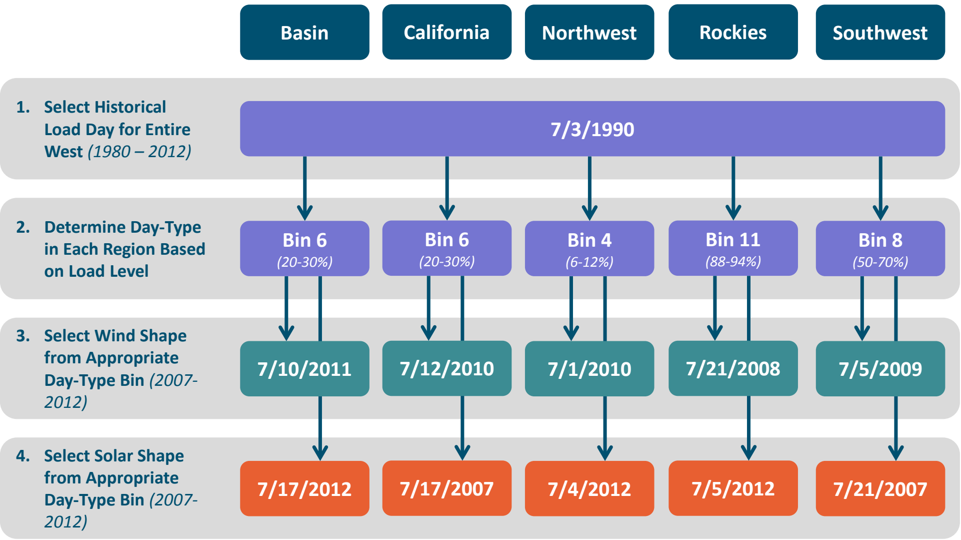
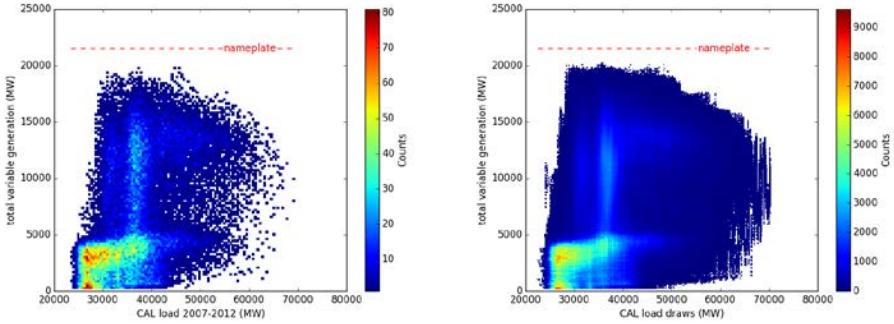


Figure 22 provides a visual comparison of the results of the methodology used to create the draws with time-synchronous load and renewable data from 2007 to 2012 for California in the Common Case. The method used to create the draws generally captures the appropriate frequency of different pairings of load and renewable output but provides a more complete distribution of possible conditions—particularly during the high load periods that are critical for reliability modeling. Additional comparative figures between time-synchronous and sampled load and renewable data are included in Section 8.4.

**Figure 22. Comparison of load and renewable samples in historical data and draws, California.[11]**


**(a) Historical (2007-2012)**
**(b) Simulated in draws**

## 3.3 Conventional Generators

With the exception of hydroelectric resources (discussed in Section 3.4), all non-wind/solar generation is assumed to be capable of providing its full rated capacity to meet load, subject to its availability given an assumed forced outage rate. For modeling purposes, this category includes traditional dispatchable resources—gas, coal, nuclear—as well as storage, demand response, and baseload renewable resources. The TEPPC Common Case includes both existing resources as well as planned additions—investments in new generation resources needed to meet policy objectives, local reliability constraints, or portfolio needs—both of which are included in the reliability assessment.

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[11] "Total variable generation" in this figure includes all wind, utility-scale and distributed solar PV, and solar thermal resources.

However, the “gap” units—plants added to the Common Case in each region to meet an assumed regional planning reserve requirement target—are removed from this analysis.

Each resource’s contribution to reliability depends on two key input parameters: (1) the maximum available output of the resource, and (2) its expected forced outage rate. Both of these parameters are defined for each resource in the TEPPC Common Case, from which this analysis draws directly the assumptions of which generation resources are assumed online.

The maximum capacity available for each resource is defined for each month of the year separately; the ratings of different resources change from one month to the next as a result of seasonal trends in temperature, which affects the maximum output of thermal units. Table 5 and Table 6 show the breakdown of available capacity in each region based on rated capacity in January and July, respectively. The impact of seasonal trends on resource availability is perhaps most evident for gas-fired generators: for example, the capability of the gas fleet in the Southwest is reduced by 5% from 28,462 MW in the winter to 27,164 MW in the summer due to the effects of temperature on output. In regions whose load peaks during the summer, this effect results in a need for additional capacity to meet a given reliability target.

**Table 5. January capacity ratings, conventional resources by generator type (MW).**

| Type | Basin | California | Northwest | Rockies | Southwest |
|---|---:|---:|---:|---:|---:|
| Nuclear | - | 2,300 | 1,145 | - | 3,937 |
| Coal | 6,974 | 2,121 | 3,001 | 6,455 | 7,807 |
| Gas | 5,079 | 37,625 | 9,095 | 6,953 | 28,462 |
| Biomass | 85 | 1,265 | 706 | 4 | 37 |

| | | | | | |
|---|---:|---:|---:|---:|---:|
| Geothermal | 911 | 2,244 | - | - | - |
| Storage | - | 1,285 | - | - | - |
| DR | 1,035 | 2,268 | 222 | 525 | 759 |
| Other | 96 | 521 | 84 | 150 | 61 |
| **Total** | **14,180** | **49,628** | **14,253** | **14,087** | **41,063** |

### Table 6. July capacity ratings, conventional resources by generator type (MW).

| Type | Basin | California | Northwest | Rockies | Southwest |
|---|---:|---:|---:|---:|---:|
| Nuclear | - | 2,300 | 1,130 | - | 3,937 |
| Coal | 6,964 | 2,121 | 2,999 | 6,433 | 7,803 |
| Gas | 4,851 | 37,117 | 8,471 | 6,504 | 27,164 |
| Biomass | 82 | 1,309 | 679 | 4 | 36 |
| Geothermal | 910 | 2,218 | - | - | - |
| Storage | - | 1,285 | - | - | - |
| DR | 1,035 | 2,268 | 222 | 525 | 759 |
| Other | 96 | 513 | 84 | 130 | 51 |
| **Total** | **13,938** | **49,131** | **13,585** | **13,596** | **39,749** |

The second important input needed to characterize these units is their forced outage rates. The fact that the forced outage rate does not appear in the calculation of a system's planning reserve margin belies its importance to the measure of system reliability. In fact, the probability of forced outages during the system peak is one of the drivers of the need to maintain a planning reserve margin, and the two are directly linked: LOLP analysis will indicate that a system with a generation fleet that has a high risk of forced outages will need to hold a higher planning reserve margin than an otherwise equivalent system with lower forced outage rates in order to meet the same standard of reliability.

This study relies on the forced outage rates assumed in the TEPPC Common Case, originally derived from NERC's Generating Availability Data System (GADS). The average forced outage rate for each type of generator in each region is shown in Table 7. The forced outage rates in the TEPPC Common Case generally vary from 3-5% depending on technology type and size. Compared to assumptions used in other LOLP studies, these outage rates appear to be relatively low; should WECC continue to investigate using LOLP analysis to measure system reliability, additional scrutiny of these assumptions may be warranted given their importance in this type of analysis. This is particularly true in the event that higher renewable penetrations may result in increased ramping and cycling among gas and coal generators, which has been linked to increased probabilities of forced outage in a number of studies.[12]

**Table 7. Average forced outage rates by generator type (%).**

| Type | Basin | California | Northwest | Rockies | Southwest |
|---|---|---|---|---|---|
| Coal | - | 3.1% | 3.1% | - | 3.1% |
| Gas | 4.7% | 3.9% | 4.4% | 4.9% | 4.6% |
| Nuclear | 3.2% | 3.2% | 3.3% | 3.2% | 3.1% |
| Biomass | 3.1% | 3.1% | 3.1% | 3.1% | 3.1% |
| Geothermal | 3.1% | 3.1% | - | - | 3.1% |
| Storage | - | 3.0% | - | - | - |
| DR | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Other | 4.0% | 4.5% | 3.1% | 9.0% | 1.5% |

## 3.4 Hydroelectric Constraints

Unlike most resources in the Western Interconnection, hydroelectric plants are generally use-limited, constrained in their operations not only by the technical limits of the generators themselves but by the underlying hydrological conditions. The availability of water to provide for generation, which varies from

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[12] Citation to EGS study

season to season and year to year, acts as a constraint on both the contribution of hydro resources to reliability and their flexibility in operations. In order to capture this constraint in the reliability analysis, RECAP examines the potential for hydroelectric resources to contribute to meeting peak demands given the range of hydrological conditions experienced from 1970-2008. The ability of the hydroelectric system in each region to contribute its capacity towards system reliability is directly proportional to the availability of hydro generation across this historic period. This section describes:

- How monthly budgets are developed for incorporation into the draws; and
- How the peaking capability of the hydro system is represented in RECAP as a function of monthly hydro conditions.

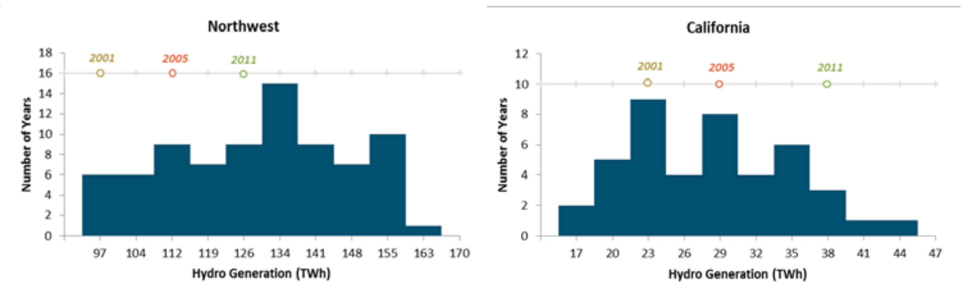
### 3.4.1 MONTHLY HYDRO BUDGETS

Monthly energy budgets for the fleet of hydroelectric generators are derived from two sources in this study:

- **Energy Information Administration (EIA) (1970-2012).** EIA Form 906 was used to calculate historical monthly hydro output for all hydro generators in the California, Southwest, Rocky Mountain, and Basin regions.
- **Northwest Power and Conservation Council (1928-2008).** The NWPCC provided simulated output from the Northwest hydro fleet based on current operating procedures and monthly hydrological conditions across a long historical record.

From each of these datasets, this study uses the hydroelectric data from 1970-2008, the chronological overlap between the two. Figure 23 shows examples of the distributions of annual energy budgets for the Northwest and California over this historical period. The specific annual budgets for 2001, 2005, and 2011, commonly used to represent dry, average, and wet hydro years, are shown for comparison purposes.

**Figure 23. Distribution of annual energy budgets, Northwest & California.**



### 3.4.2 PEAKING CAPABILITY

The RECAP model treats time steps independently for ease of computation, which makes it necessary to create approximations for energy- or use-limited resources. Hydro is the most significant of these and presents a substantial modeling challenge when it comes to peaking capability for reliability.

In the Northwest, where the majority of generating capacity is hydroelectric, the contribution of the hydro fleet to reliability has historically been modeled based on its “sustained peaking capability”: the ability of the fleet to sustain a certain level of output across durations of two, four, and ten hours through different seasons and under different hydrologic conditions. These constraints are derived by the NWPCC through a hydrologic model of the operations of the major river systems and dams in the Pacific Northwest.

For this study, hydro peaking capability within RECAP was constrained using relationships between the monthly hydro budget for a region and the sustained 4-hour peaking capability of its hydro generators.[13] The 4-hour peaking capability is used because in a power system with adequate reliability, resource adequacy shortages rarely last longer than 4 hours—either native load drops below available capacity or additional resource can be brought online. The average outage duration in RECAP is 2 hours when the loss of load frequency is equal to one event per ten years. Because of this, 4-hour sustained peaking was judged to be appropriately conservative, without being over-constraining. The relationship between hydrologic conditions and peaking capability is specific to month and developed using the sustained peaking constraints provided by the NWPCC, as shown in Figure 24.

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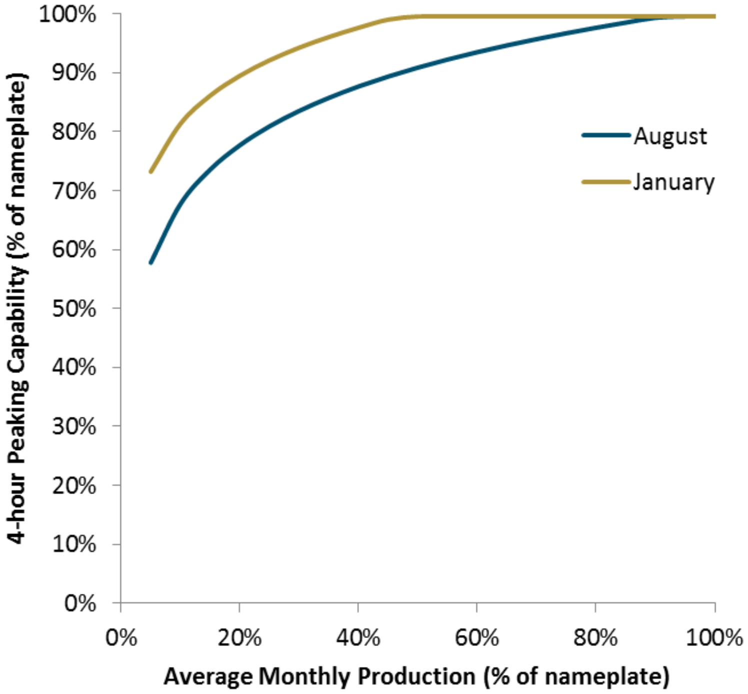
[13] Because RECAP treats each time step independently, a full implementation of the sustained hydro peaking capability constraints is not possible. Therefore, a simplified application of the sustained peaking constraints was used.

**Figure 24. Example hydro peaking constraints used in RECAP analysis**



In the absence of comparable data for other regions, this study assumes that the relationship between monthly energy budgets and 4-hour sustained peaking capability is constant across regions, applying the normalized curves to the hydro fleet in each region. This is likely an oversimplification; however, in benchmarking exercises with other regions where other detailed studies of hydro resource adequacy has been done, principally California, the sustained peaking functions resulted in an effective load carrying capability for hydro that agreed closely with current planning assumptions (10,878 hydro ELCC vs. 10,928 hydro dependable capacity from the California Energy Commission).[14] Because of this agreement, and due to the lack of detailed information for other regions, the generalized sustained peaking relationships were judged appropriate for this study.

## 3.5 Imports

In this reliability assessment, each region is modeled independently from its neighbors. While a West-wide reliability model may provide interesting information, the regional scope of the reliability assessment is chosen in order to better reflect the geographic scale at which resource planning occurs and reliability-driven investment decisions are made. Consequently, in each region, an assumption on the degree to which imports may contribute to system reliability is needed.

The availability of imports and their contribution to the reliability of a region depends on a number of factors, including the physical limits of the transmission systems, a region's long-term contracts or ownership of remote resources, the balance between loads and resources in different parts of the West, and the underlying economics of power markets. There is not a single consensus approach used to determine the potential contribution of imports to meeting a region's reliability requirements; rather, a number of approaches have been used in an attempt to quantify the availability of imports:

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[14] California Energy Commission, *Summer 2012 Electricity Supply and Demand Outlook*. Available at: http://www.energy.ca.gov/2012publications/CEC-200-2012-003/CEC-200-2012-003.pdf.

- **Physical limits of the transmission system.** The physical limits of transmission lines that connect an electric system to its neighbors provides an upper-bound estimate of the possible contribution of imports to an electric system's reliability. This approach has been used in California—historically a major net importer from both the Northwest and Southwest during its summer peak periods—by both the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC).
- **Ownership of remote resources.** A number of major generating resources in the West are either owned or contracted by utilities: the output from the Palo Verde nuclear facility, Hoover Dam, and a number of large coal generators. In its evaluation of resource adequacy in each region of the Western Interconnection during the development of the Common Case, TEPPC relies on this information to characterize the contribution of imports (and exports) to the planning reserve margin in each area.
- **Assessment of surplus generation capacity in neighboring systems.** A resource planner may attempt to evaluate the future availability of surplus generation capacity on neighboring systems. For example, in its resource adequacy assessment, the Northwest Power and Conservation Council (NWPCC) examined the balance of loads and resources in California to inform its decision to assume the availability of 2,500 MW of imports during the winter period due to California's relatively low winter loads and the consequent availability of capacity needed to meet its own summer peak.[15]
- **Observation of historical import patterns.** Historical data on the dynamics of imports to an electric system provides another useful point

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[15] Northwest Power and Conservation Council, *Pacific Northwest Power Supply Adequacy Assessment for 2019*. Available at: http://www.nwcouncil.org/media/7084800/2014-04.pdf.

> of reference. The California ISO, in its *2014 Summer Loads & Resources Assessment*,[16] establishes a range of import availability of 8,500 – 11,000 MW that is, in part, informed by its historical operating experience.

This study uses a combination of these approaches, deferring to regional planning efforts for this important assumption when possible. For both California and the Northwest, the question of how much to rely on imports for reliability has been asked and answered in a number of regional planning forums, and this study uses the general results from these exercises to inform its analysis. In the other three regions, no such regional-level planning forum exists; for these regions, the availability of imports (and, in parallel, the obligation to export) is determined on the basis of remote ownership of generation resources. The contribution of imports to reliability in each region, as well as the information used to derive each assumption, is shown in Table 8.

**Table 8. Assumptions used to quantify imports & exports in reliability modeling.**

| Region | Net Import Capacity (MW) | Description |
|---|---|---|
| Basin | 445 | **Remote resource ownership (imports):**<br>• Craig 1 & 2: 169 MW<br>• Hayden 1 & 2: 87 MW<br>• Intermountain Power Project: 450 MW<br>**Remote resource ownership (exports):**<br>• North Valmy 1 & 2: 261 MW |

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[16] California Independent System Operator, *2014 Summer Loads & Resources Assessment*. Available at: http://www.caiso.com/Documents/2014SummerAssessment.pdf.

| Region | Net Import Capacity (MW) | Description |
|---|---|---|
| California | 11,768 | **Regional planning assumption:**<br>• *CEC Summer Assessment*[17]: 13,118 MW<br>**Adjustment for Intermountain Power Project:**<br>• Modeled in LADWP<br>• 1,350 MW deducted from import capability (CA ownership share of 1,800 MW plant |
| Northwest | 2,500 | **Regional planning assumption:**<br>• NWPCC[18]: 2,500 MW<br>• Available in winter only (0 MW in summer) |
| Rocky Mountains | -602 | **Remote resource ownership (exports):**<br>• Craig 1 & 2: 423 MW<br>• Hayden 1 & 2: 179 MW |
| Southwest | -1,737 | **Remote resource ownership (imports):**<br>• Craig 1 & 2: 254 MW<br>• North Valmy: 261 MW<br>**Remote resource ownership (exports):**<br>• Hoover: 1,265 MW<br>• Palo Verde 1, 2 & 3: 1,078 MW |

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[17] California Energy Commission, *Summer 2012 Electricity Supply and Demand Outlook*. Available at: http://www.energy.ca.gov/2012publications/CEC-200-2012-003/CEC-200-2012-003.pdf.

[18] Northwest Power and Conservation Council, *Pacific Northwest Power Supply Adequacy Assessment for 2019*. Available at: http://www.nwcouncil.org/media/7084800/2014-04.pdf.

# 4 Phase 1: Results

## 4.1 Regional Reliability Results

### 4.1.1 RELIABILITY STATISTICS

The results of the stochastic reliability assessment for the 2024 Common Case, summarized in Table 9, indicate that each region meets the study's assumed threshold for reliability of LOLF < 0.1. A small probability for loss of load events is identified in the Basin and Rockies regions; however, the size of these risks is not large enough to necessitate the addition of incremental capacity. Consequently, this modeling effort identifies no need for additional capacity beyond the resources of the Common Case to meet traditional reliability thresholds.

**Table 9. Reliability statistics in each region, Common Case.**

| Reliability Metric[19] | Basin | California | Northwest | Rockies | Southwest |
|---|---|---|---|---|---|
| Loss of Load Frequency | 0.02 | -- | -- | 0.04 | -- |
| Loss of Load Expectation | 0.04 | -- | -- | 0.09 | -- |
| Expected Unserved Energy | 10.6 | -- | -- | 21.9 | -- |

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[19] No operating reserves are assumed, consistent with the original conception of the "1-in-10 standard."

It is important to note that this result does not imply the adequacy of today's generation fleet to meet loads reliably in 2024. In addition to a substantial buildout of renewable resources to meet state policy goals, the Common Case also includes a number of conventional generator additions based on plans submitted to TEPPC by its members as well as based on information gathered by stakeholders in the TEPPC process. These additional resources represent planned investments without which the system might not meet the requisite reliability thresholds evaluated in this study.

While the High Renewables Case is still under development at the time of this report and has not been modeled in RECAP, the addition of incremental renewable capacity in each region will have the directional impact of decreasing LOLF (and other reliability metrics) relative to the Common Case. Accordingly, no capacity deficits due to a shortfall of generation capacity are anticipated in the High Renewables Case.

### 4.1.2 PLANNING RESERVE MARGINS

While the primary function of the RECAP model is to compute these reliability statistics for an electric system, it also provides a snapshot of the more traditional planning reserve margin. The resulting planning reserve margin for each region is summarized in Table 11.

**Table 10. Planning reserve margins in each region, Common Case (MW).**

| Type | Basin | California | Northwest | Rockies | Southwest |
|---|---|---|---|---|---|
| Conventional Generators | 14,182 | 49,779 | 14,314 | 14,093 | 41,065 |
| Hydro | 1,915 | 10,878 | 26,209 | 1,489 | 3,568 |
| Wind & Solar | 1,002 | 7,615 | 854 | 845 | 2,749 |

| | | | | | |
|---|---|---|---|---|---|
| Imports | 445 | 11,768 | 2,500 | -603 | -1,737 |
| Total Supply | 17,544 | 80,040 | 43,877 | 15,824 | 45,645 |
| 1-in-2 Peak Demand | 15,013 | 64,007 | 33,196 | 13,286 | 34,574 |
| *Reserve Margin (%)* | *17%* | *25%* | *32%* | *19%* | *32%* |

The calculated planning reserve margin is highly dependent on the conventions used in its evaluation, which are outlined in Table 10. In some cases, these conventions differ from the accounting method historically used by TEPPC to ensure resource adequacy in the development of the Common Case—most notably in the use of ELCC to measure the contribution of variable resources and hydro to the planning reserve margin.

### Table 11. Conventions used to count capacity towards the "planning reserve margin"

| Category | RECAP Convention |
|---|---|
| **Dispatchable Generation**<br>• Biomass<br>• Geothermal<br>• Gas<br>• Coal<br>• Nuclear<br>• DR<br>• Storage | 100% of maximum rated capacity |
| **Hydro**<br>• Conventional hydro<br>• Small hydro | Effective load carrying capability |
| **Variable Renewable Generation**<br>• Solar PV<br>• Solar Thermal<br>• Wind | Effective load carrying capability |
| **Imports/Exports**<br>• Specified<br>• Unspecified | 100% of capacity of remote contracted resources + regional planning assumption for unspecified imports |

### 4.1.3 TARGET PLANNING RESERVE MARGINS

The RECAP model can be used to derive target planning reserve margins—the reserve margin needed to meet the reliability threshold of LOLF = 0.1—given the characteristics of its loads and resources. Figure 25 shows the relationship between the loss of load frequency and the planning reserve margin in each region. While each region's curve is unique, the general functional form is the same: increasing the reserve margin of an electric system causes a decrease in the expected LOLF; this decrease is nonlinear and shows diminishing returns as more capacity is added to the system. For each region, the point on this curve at which the LOLF is equal to 0.1 represents the planning reserve margin needed to meet that reliability standard.[20] Based on this analysis, each region's target reserve margin is shown in Table 12.

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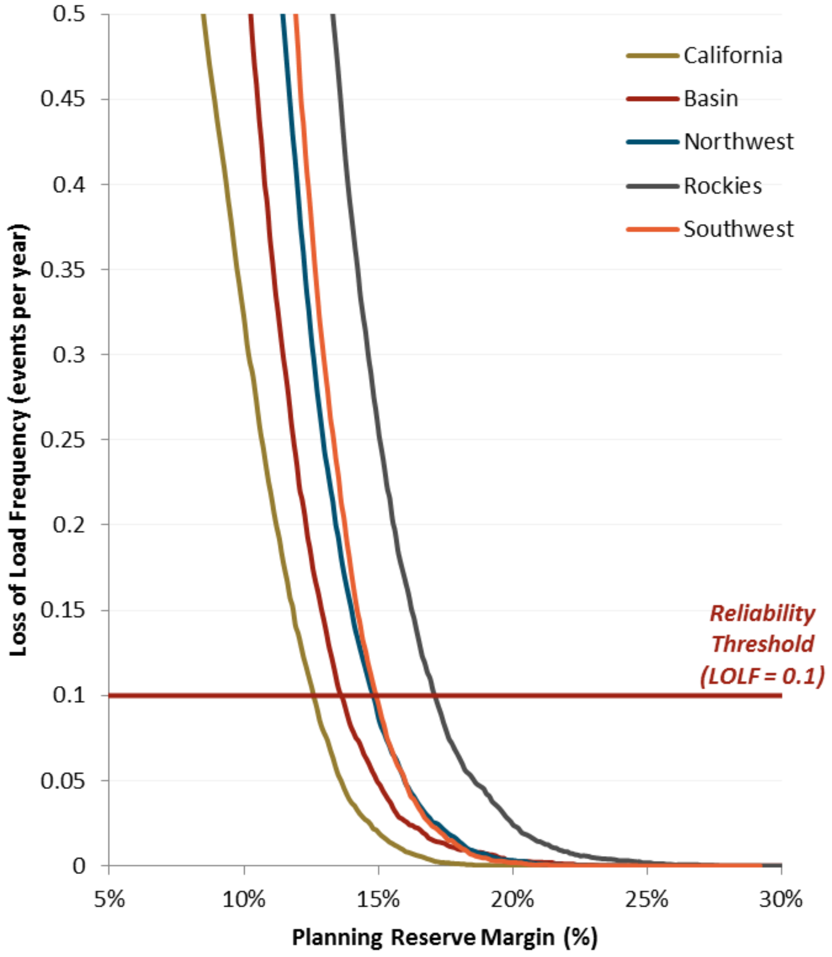
[20] It is important to note that while this study interprets the "1-in-10" standard to reflect one loss of load event in ten years, there is not uniform agreement on what standard should be used. The "1-in-10" standard itself has several interpretations, each of which would imply a different target planning reserve margin.

### Figure 25. Loss of load frequency as a function of planning reserve margin



### Table 12. Target planning reserve margins for each region

| Type | Basin | California | Northwest | Rockies | Southwest |
|---|---|---|---|---|---|
| Target Reserve Margin (%) | 14% | 13% | 15% | 17% | 15% |

The difference in target planning reserve margin standards between regions is expected and is primarily due to the difference in region size, composition of the generation fleet, and contingency size. First, a larger region will have greater load and resource diversity; load diversity dampens extreme peak loads while resource diversity reduces the likelihood of a critical forced outage occurring simultaneously. Resource type is important due to its outage frequency, repair rates, and or seasonal patterns in dependable capacity. Finally, a system with large contingencies, such as one with a large portion of load met with only a few generators, will tend to need a higher planning reserve margin because generator failure in just 1-2 locations may be enough to cause a loss of load event.

## 4.2 Renewable Effective Load Carrying Capability

One of the distinguishing features of the RECAP model is its ability to produce estimates of the effective load carrying capability (ELCC) of variable generation, a measure of its contribution to reliability relative to a perfectly reliable generation resource. This metric provides a more analytically robust measure the capacity value of variable resources than the rules of thumb commonly used today. ELCC is therefore a useful metric for resource planning in several respects: (1) it can be used to measure capacity contributions from variable renewable resources in the traditional planning reserve margin framework;[21] and (2) is provides a useful measure of the value provided by prospective renewable investments with which procurement decisions can be more effectively made to mitigate costs to ratepayers.

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[21] In California, the CPUC is currently working to incorporate ELCC values for wind and solar resources in its Resource Adequacy proceeding.

### 4.2.1 TECHNOLOGY-SPECIFIC ELCC CURVES

Marginal ELCC curves for wind and solar technologies in each region are plotted in Figure 26 through Figure 30. Each curve is derived assuming that only that variable resource is present on the system; such curves inherently do not account for the benefits of resource diversity, which can result in greater ELCCs for variable resources (see Section 4.2.2). These results suggest a number of observations on the nature of ELCC for renewable resources across the Western Interconnection:

- In all regions, wind and solar ELCC values exhibit diminishing returns to scale. As penetrations increase, such variable resources have a reduced benefit to system reliability as the net peak demand shifts away from hours in which production is concentrated.
- In most regions, the marginal ELCC of solar PV at low penetrations is relatively high (50-60%) and aligns with common rules of thumb used to attribute capacity credits to solar in many planning exercises. This reflects the coincidence of solar generation with peak load conditions in most of the regions. The notable exception to this observation is the Northwest, where the timing of the peak demand during the evening in the winter results in very low ELCC values for solar resources.
- The marginal ELCC of solar PV decreases rapidly in most regions with increasing penetration; this is a result of the effect of the shifting of the net load peak towards the evening when solar production drops. At high penetrations, traditional rules of thumb based on the coincidence of solar production with peak load become highly inaccurate in the value they attribute to solar resources.
- Marginal ELCC for solar thermal resources (calculated only for California the Southwest, and the Basin, which each have a small penetration of

solar thermal resources in the Common Case) exhibits the same general trend as solar PV; however, the marginal ELCC values are slightly higher due to the fact that a number of these plants are assumed to have thermal storage, which allows them to sustain higher levels of output through peak periods in the late afternoon and early evening.

+ At low penetrations, marginal ELCC values for wind range from 15-30% of nameplate capacity; as penetration increases, the marginal ELCC declines, though at a rate slower than the decline for solar technologies.

**Figure 26. Marginal ELCC for wind & solar resources, Basin region.**

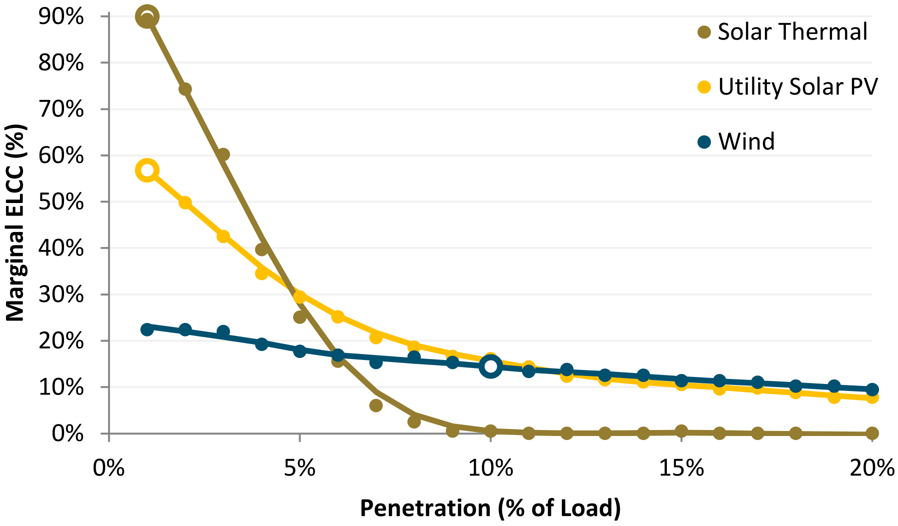


Figure 27. Marginal ELCC for wind & solar resources, California region.

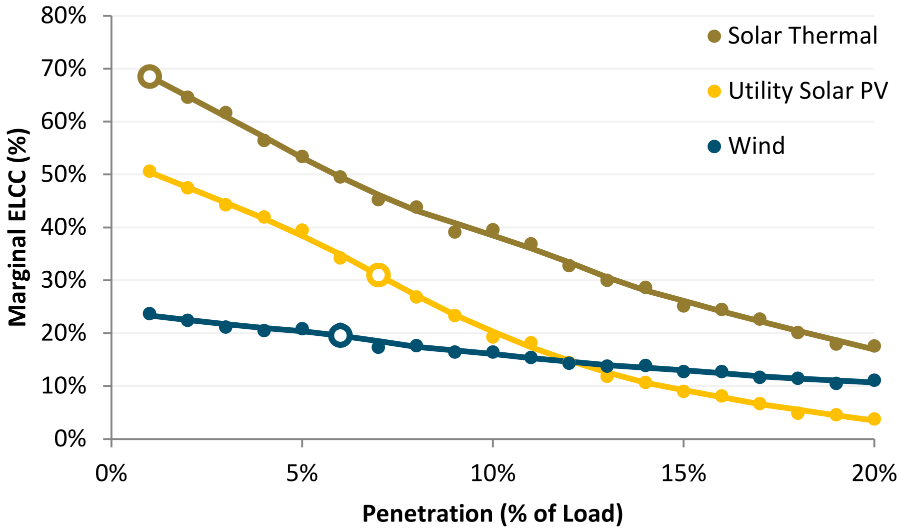


Figure 28. Marginal ELCC for wind & solar resources, Northwest region.

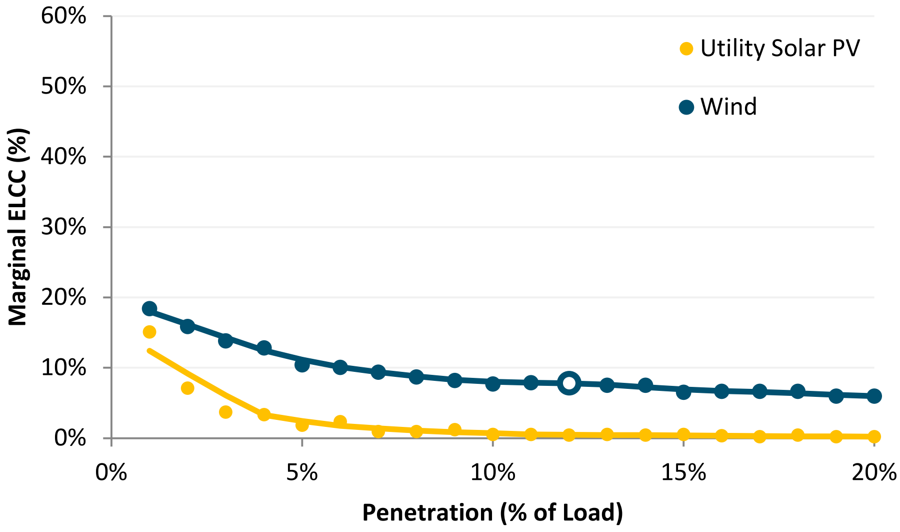


Figure 29. Marginal ELCC for wind & solar resources, Rocky Mountain region.

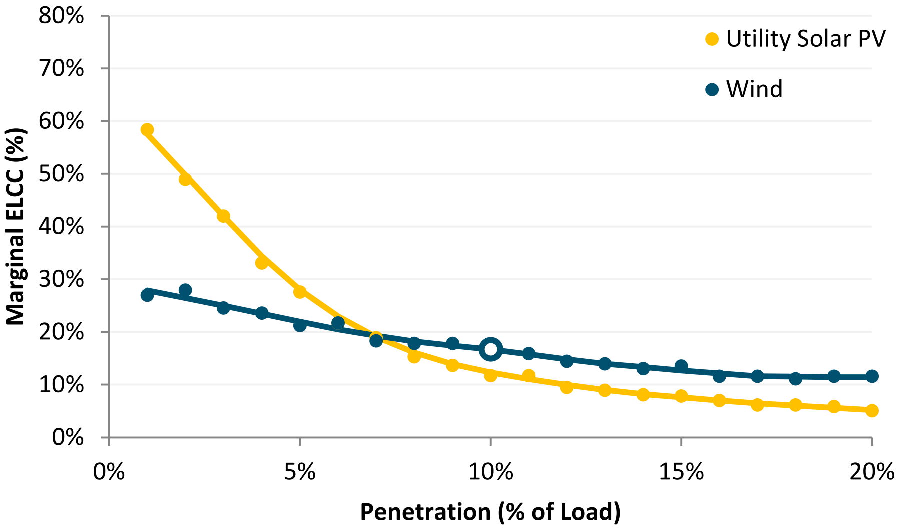
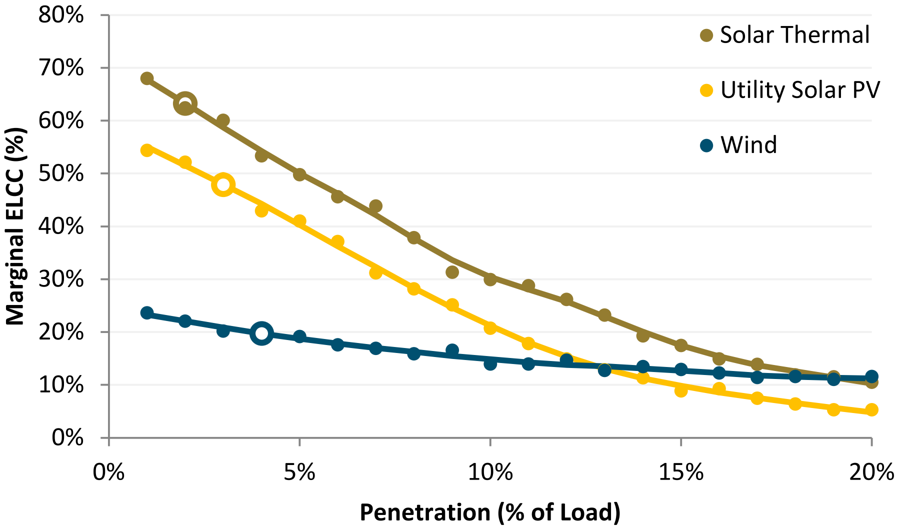


Figure 30. Marginal ELCC for wind & solar resources, Southwest region.

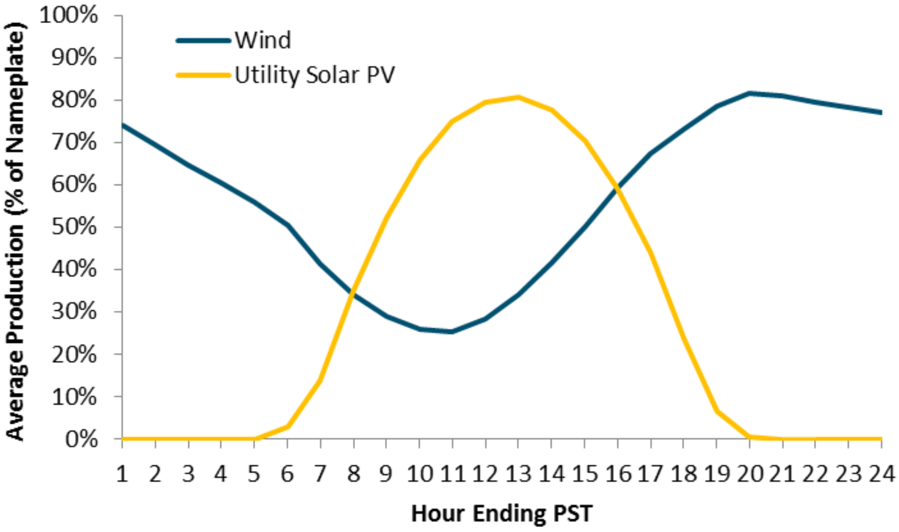


### 4.2.2 PORTFOLIO EFFECTS & BENEFITS OF DIVERSITY

The technology specific ELCC curves shown in section 4.2.2 are useful for illustrating diminishing returns from a single resource type for resource adequacy, but they do not give an accurate picture of the total resource adequacy value of a portfolio of variable generation. The portfolio ELCC value differs from the sum of the individual resource ELCC values due to two factors: portfolio effects—positive or negative resource complementarity—and diversity—reduction in production variability.

To illustrate the impact of complementary production profiles, take Figure 31, which shows average wind and solar production in July. As increasing amounts of solar are added to the system, the net peak will shift later in the evening; this effect is reflected in the declining marginal ELCC curves. However, this shift in the timing of the net peak load also increases the contribution of wind, which has higher expected production later in the evening, to system reliability. The net result is that the wind and solar resources complement one another and result in a greater ELCC together than the sum of the two separately.

**Figure 31. Average wind and solar in California for July**



The magnitude of this effect can be quantified using Table 13, which shows the combined ELCC of wind and solar resources for a variety of portfolio combinations of the two in California. In the 2024 Common Case, California has approximately 10% solar PV and 6% wind penetration by energy.[22] Referencing Table 13, this total resource mix yields an ELCC of 6,924 MW; however, when examined separately, a 6% wind penetration and a 10% solar penetration yield ELCC values of 1,213 MW and 4,916 MW, respectively. The sum of 1,213 MW and 4,916 MW gives 6,129 MW, short of the total portfolio value by 795 MW. The missing 795 MW, in this case, is the portfolio effect and is 12% of the total portfolio ELCC value. Resources with a high degree of correlation, such as solar

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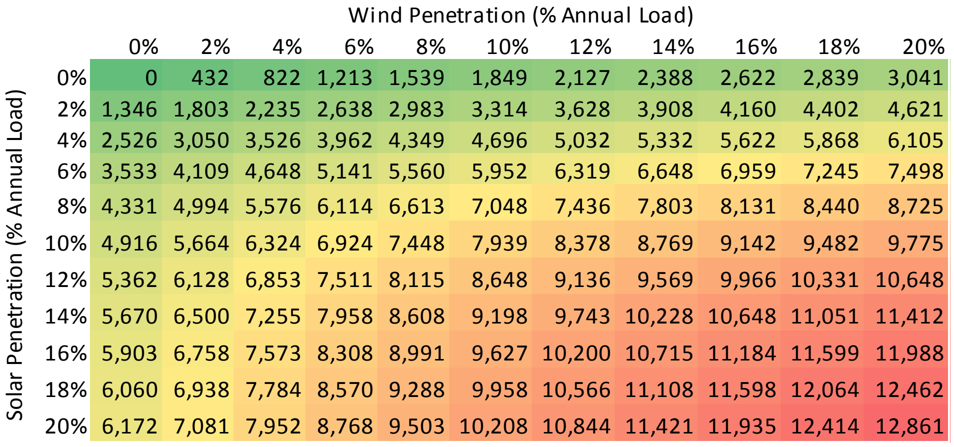
[22] For purposes of illustrative simplicity, the small penetration of solar thermal in California is ignored in this example.

thermal and solar PV, show negative portfolio effects because they both tend to shift net peak load in the same ways.

**Table 13 Effective load carrying capability in megawatts as a function of wind and solar penetration in California**



| Solar Penetration (% Annual Load) | Wind Penetration (% Annual Load) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0% | 2% | 4% | 6% | 8% | 10% | 12% | 14% | 16% | 18% | 20% |
| 0% | 0 | 432 | 822 | 1,213 | 1,539 | 1,849 | 2,127 | 2,388 | 2,622 | 2,839 | 3,041 |
| 2% | 1,346 | 1,803 | 2,235 | 2,638 | 2,983 | 3,314 | 3,628 | 3,908 | 4,160 | 4,402 | 4,621 |
| 4% | 2,526 | 3,050 | 3,526 | 3,962 | 4,349 | 4,696 | 5,032 | 5,332 | 5,622 | 5,868 | 6,105 |
| 6% | 3,533 | 4,109 | 4,648 | 5,141 | 5,560 | 5,952 | 6,319 | 6,648 | 6,959 | 7,245 | 7,498 |
| 8% | 4,331 | 4,994 | 5,576 | 6,114 | 6,613 | 7,048 | 7,436 | 7,803 | 8,131 | 8,440 | 8,725 |
| 10% | 4,916 | 5,664 | 6,324 | 6,924 | 7,448 | 7,939 | 8,378 | 8,769 | 9,142 | 9,482 | 9,775 |
| 12% | 5,362 | 6,128 | 6,853 | 7,511 | 8,115 | 8,648 | 9,136 | 9,569 | 9,966 | 10,331 | 10,648 |
| 14% | 5,670 | 6,500 | 7,255 | 7,958 | 8,608 | 9,198 | 9,743 | 10,228 | 10,648 | 11,051 | 11,412 |
| 16% | 5,903 | 6,758 | 7,573 | 8,308 | 8,991 | 9,627 | 10,200 | 10,715 | 11,184 | 11,599 | 11,988 |
| 18% | 6,060 | 6,938 | 7,784 | 8,570 | 9,288 | 9,958 | 10,566 | 11,108 | 11,598 | 12,064 | 12,462 |
| 20% | 6,172 | 7,081 | 7,952 | 8,768 | 9,503 | 10,208 | 10,844 | 11,421 | 11,935 | 12,414 | 12,861 |

Diversity within a given resource type also has value because a reduction in variability on peak, for a given expected value, leads to a higher ELCC. This means that the ELCC of wind or solar resources will tend to be higher when the size of the area examined is increased, provided a consistent resource quality.

## 4.3 Future Application of RECAP

The analysis of reliability in this study is intended as a precursor to the flexibility assessment and as a demonstration of a modeling framework; it is not a substitute for a rigorous planning reserve margin study in each of the regions of the Western Interconnection, including an additional examination of regional reliability standards. Nonetheless, the RECAP model provides a flexible platform from which more detailed reliability analysis of individual balancing authorities, regions, or the Western Interconnection as a whole is possible. In order to apply the RECAP model in the context of its continued use in reliability analysis at WECC, additional refinement to inputs and assumptions will improve the model's characterization of reliability in the area of focus.

- **Develop renewable profiles that reflect expected output patterns from actual plants.** In this study, renewable profiles are based on data sets whose assumptions underlying resource performance do not necessarily align with observations of existing plants. For example, in a number of cases, the power curve used to derive profiles in the WIND Toolkit yields a higher estimate of plant capacity factors than are observed in existing wind plants at the same geographic location. Developing a single data set of renewable profiles that provides a reasonable representation of both existing and future resources will continue to present a challenge to resource planners, yet as efforts to develop additional data on wind and solar performance continue to evolve, ensuring the best possible representation of performance is crucial to the study of reliability.
- **Review forced outage rate assumptions.** The forced outage rates of generation resources—a characteristic oft-overlooked in the PRM framework of reliability—have a first-order impact on the results of LOLP analysis. NERC's GADS provides a reasonably comprehensive dataset of observed historical patterns of forced outages, but studies should also consider whether forced outage rates may change in the future, especially due to increased cycling and ramping requirements at higher renewable penetrations.
- **Determine appropriate assumptions for contribution of imports to reliability.** As discussed in Section 3.5, one notable challenge in reliability planning is the determination of how much to rely on imports

for reliability, a determination that typically requires some discretion on the part of the resource planner. Depending on the footprint of the area of study, the strength of its transmission links to neighboring areas, the historical utilization of those interties during peak periods, and the availability of generation resources in neighboring areas may all provide some basis for this assumption.

- **Conduct detailed assessment of sustained peaking capability of hydroelectric fleet.** This study incorporates a portion of the detail from the NWPCC's evaluation of the sustained peaking capability of the hydroelectric fleet in the Pacific Northwest; however, comparable efforts to measure the possible contribution of hydro resources under a variety of hydro conditions have not been undertaken in such detail in other regions of the West. In the absence of such measurements, this study generalizes the constraints used in resource planning in the Northwest and applies them to the other regions of the West in order to approximate limitations in the output of hydro resources across a variety of conditions. To the extent that hydro resources account for a non-trivial share of the generating capacity in the footprint of the area of interest (e.g. California in this study), a more detailed representation of the potential range of peaking capabilities of hydro resources will enhance the reliability assessment.

# 5 Phase 2: Data & Methods *(forthcoming in July)*

# 6 Phase 2: Results *(forthcoming in July)*

# 7 Conclusions *(forthcoming in July)*

# 8 Technical Appendix

## 8.1 RECAP Methodology

The RECAP model works by simulating load and generating resources over a large number of years to find events where load exceeds available generation. This Monte Carlo simulation of power system resource adequacy has long been established in industry[23,24] and can be divided into discussions on the treatment of dispatchable capacity, hydro, DR & storage, and load & variable generation, and imports. Some are these are described in detail in the body of this report and are only referenced here.

One critical detail of the RECAP methodology, which is common among most LOLP frameworks, is that no dispatch or optimization is done when determining resource adequacy. This is done for ease of computation, but it means that certain use-limited resources such as hydro, demand response, and storage must be simplified. In addition, certain contributors to unserved energy, such as extreme forecast error or minimum down-time, are not considered, and would instead by captured in the REFLEX production simulation analysis.

In a future power system where flexible load and short duration storage may be critical to bulk system reliability, additional linkages between hours will be

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[23] R. Billinton and R. N. Allan, Reliability Evaluation of Power Systems, Second ed. New York: Plenum Press, 1996.
[24] R. Billinton and W. Li, Reliability Assessment of Electric Power Systems Using Monte Carlo Methods. New York: Plenum Press, 1994.

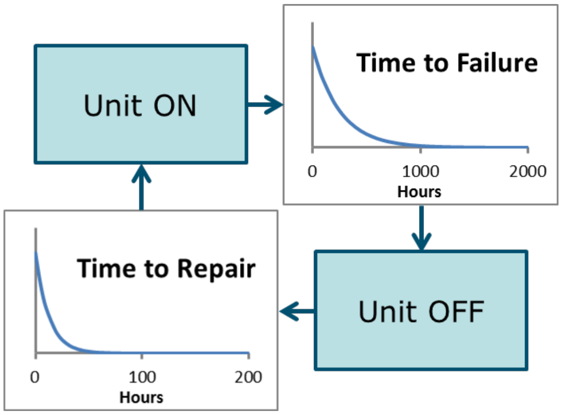
necessary within the basic time-sequential framework presented here. However, this type of analysis is beyond the current modeling needs for WECC.

### 8.1.1 DISPATCHABLE CAPACITY

The monthly generator maximum capacity is assumed to be available to serve load except when a generator is off as part of a forced outage. Forced outages are simulated using a Markov-Chain framework, shown in Figure 38, with an exponential distribution assumed for time to failure and time to repair.

Seasonal maintenance is not included in RECAP with the assumption that, when optimally scheduled, seasonal maintenance should have little impact on reliability. In contrast, "forced maintenance," which is often separated from forced outage as a function of notification time, is included within the forced outage Monte Carlo framework.

**Figure 32. Markov-Chain forced outage model**



### 8.1.2 HYDRO

Hydro peaking capacity is included as a function of monthly energy budgets and generalized relationships between energy budgets and sustained 4-hour peaking capability. This is explained in further detail in section 3.4.2.

### 8.1.3 DEMAND RESPONSE & STORAGE

Both demand response and energy storage are modeled as resources within the generator stack. The demand response capacity in the Common Case is already derated based on its ability to serve load during reliability events. Storage resources were assumed to contribute their full nameplate capacity because the storage capacity of all pumped hydro and most battery storage within the Common Case exceeds the longest reliability events observed in the model.

### 8.1.4 LOAD & VARIABLE GENERATION

The RECAP model uses the draw methodology discussed in section 3.2.3 to match load profiles to renewable profiles in an effort to expand sample size while enforcing correlations.

### 8.1.5 IMPORTS

The RECAP model did not simulate individual transmission lines, thus transmission outages were not included in in the simulation. While transmission and distribution failures are the most common cause of customer outages, most are not connected to system resource adequacy. Imports were informed by the regional planning assumptions discussed in section 3.5.

### 8.1.6 RECORDING LOSS OF LOAD EVENTS

A loss-of-load event occurs when load exceeds the sum of generation resources as shown in Figure 39. In this example, 10,000 megawatts of resources are removed from the California generator stack in an effort to force loss of load conditions for illustration. In this example day the model would record a single loss of load event, three hours of lost load, and 3,500 MWh of unserved energy. Dividing the running total of each category by the number of years simulated gives loss of load frequency (LOLF), loss of load expectation (LOLE), and expected unserved energy (EUE), respectively.

The convergence behavior of the RECAP model is shown in Figure 40. This particular example is for California adjusted to be in load resource balance with a loss of load frequency of 0.1. Expected unserved energy is shown along with loss of load frequency as it is the slowest to converge. In each of the regions, 5,000 years of simulation was sufficient to reach convergence for each of the reliability statistics.

## Figure 33. A day with a loss of load event in California from an example Monte Carlo simulation

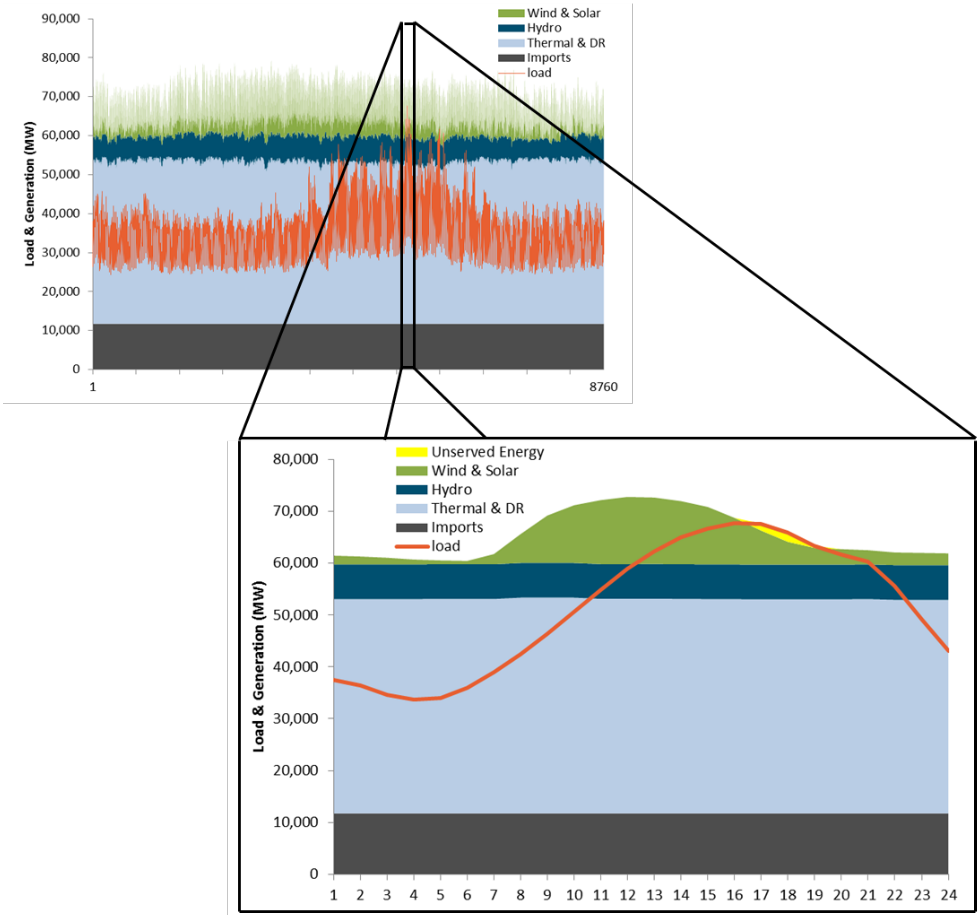
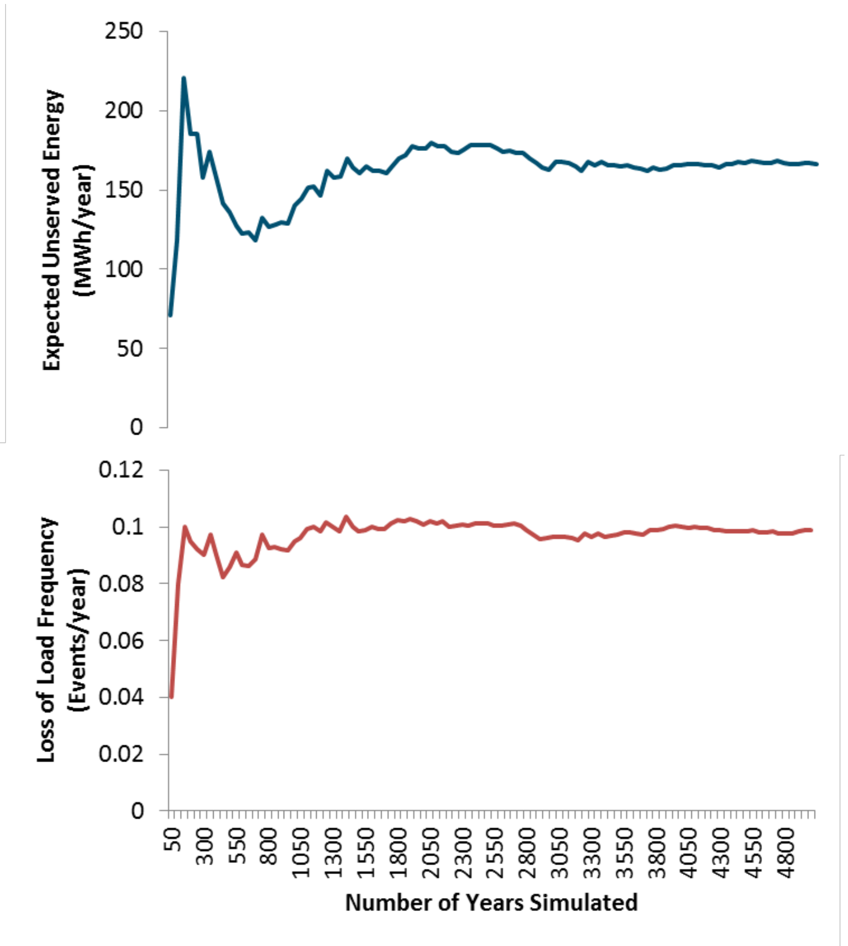


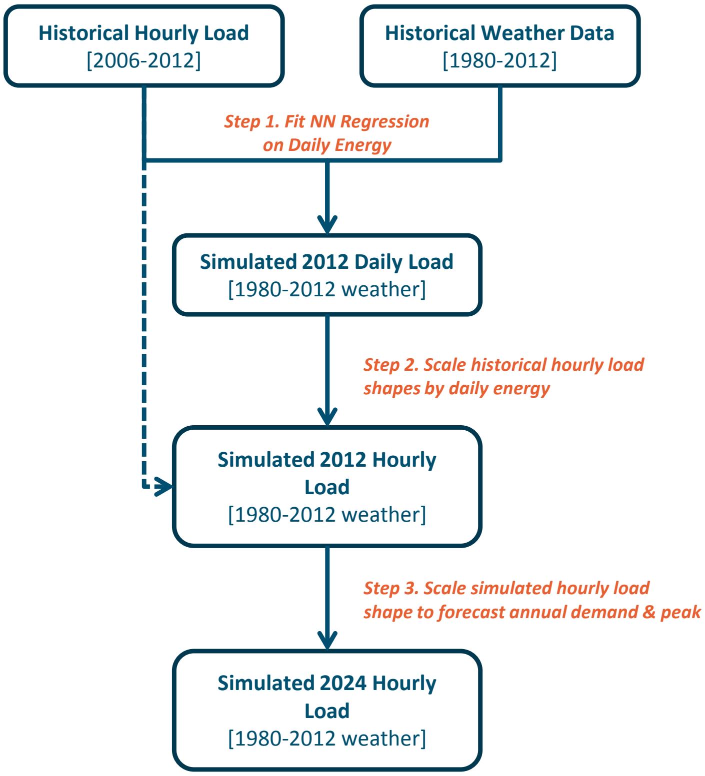
Figure 34. Convergence of reliability metrics in RECAP



## 8.2 Development of Load Shapes

Simulated hourly load shapes are generated for this analysis using a neural network-based approach under historical weather conditions. This approach is applied to each TEPPC load area to create load shapes that reflect the load level forecast in the 2024 Common Case that reflect the weather patterns observed between 1980 and 2012. The approach is shown in Figure 38 and each step (1-3) is described in more detail below.

**Figure 35: Methodology for creating 2030 load profiles**



**Step 1. Develop an artificial neural network using a daily weather indicators as explanatory variables to predict daily load under historical weather conditions.** Table 17 shows the weather stations used in the regression for each load area. The weather indicators included in the neural network are include: daily minimum, maximum, and average temperature, lag/lead temperature (D-1, D-2,

D+1), and a solar azimuth variable. Additional indicators include a weekday indicator, semi-holiday[25] and real-holiday indicators, a spring/fall indicator, and a day number index that is utilized in to capture any additional trends in the underlying load data not explained by other variables (economic factors, population growth, load types, etc.). The neural network model is used to predict daily energy for 2012 demographic and economic conditions under historic weather conditions.

### Table 14. Weather stations included in neural network model for each load area.

| Load Area | Weather Stations |
|---|---|
| AVA | Spokane, Yakima, Kalispell |
| AZPS | Phoenix, Las Vegas NV, Durango, Tucson |
| BANC | Sacramento, Redding |
| BPAT | Seattle, Olympia, Yakima, Kalispell, Bend, Eugene |
| CHPD | Yakima |
| CIPB | San Francisco_2, San Jose_2, Sacramento |
| CIPV | Fresno, Bakersfield, Redding |
| CISC | Los Angeles_3, Bakersfield, Imperial, San Diego, Las Vegas NV |
| CISD | San Diego, Imperial, Los Angeles_3 |
| DOPD | Yakima |
| EPE | Las Cruces, Roswell |
| GCPD | Yakima |
| IID | Imperial, San Diego |
| IPFE | Boise |
| IPMV | Boise, Idaho Falls |
| IPTV | Boise, Idaho Falls |

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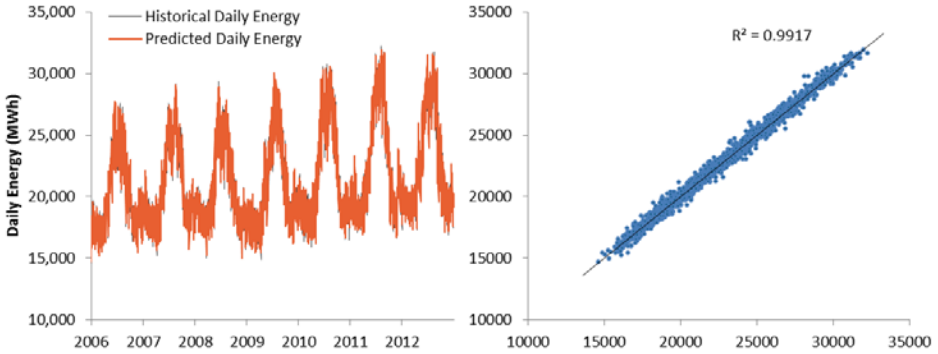
[25] A semi-holiday includes days such as the Friday after Thanksgiving, which are not Federal holidays, but are not standard work days and may have highly atypical load patterns.

| Load Area | Weather Stations |
|---|---|
| LDWP | Los Angeles_3, Bakersfield, Las Vegas NV |
| NEVP | Las Vegas NV |
| NWMT | Missoula, Great Falls, Bozeman_1, Billings, Sioux Falls, Aberdeen |
| PACW | Medford, Eugene, Redding |
| PAID | Idaho Falls, Pocatello |
| PAUT | Salt Lake City, Payson |
| PAWY | Rock Springs, Idaho Falls |
| PAX | Rock Springs, Idaho Falls, Salt Lake City, Payson, Pocatello |
| PGE | Portland, Salem |
| PNM | Albuquerque, Las Vegas NM, Santa Fe, Roswell |
| PSCO | Denver_1, Colorado Springs |
| PSEI | Seattle, Olympia |
| SCL | Seattle, Olympia |
| SPPC | Reno, Elko |
| SRP | Phoenix, Tucson |
| TEPC | Tucson, Phoenix |
| TIDC | Turlock, Sacramento, Fresno |
| TPWR | Tacoma |
| WAAZ | Durango, Las Vegas NV, Phoenix |
| WACO | Grand Junction, Durango, Rock Springs |
| WANM | Durango, Albuquerque |
| WAUW | Omaha, Billings, Rapid City, Bismarck, Fargo, Sioux Falls |
| WAWY | Cheyenne, Rock Springs, Casper, Gillette |
| WAXTEPC | Tucson, Phoenix, Durango, Albuquerque, Las Vegas NV |

Figure 39 shows a comparison between the daily energy predicted by the neural network model and the actual historical daily energy for the period 2006-2012. As shown in this example, the neural network model serves as a highly accurate predictor of daily energy across a large number of samples.

**Figure 36. Predicted vs. actual El Paso Electric daily energy for 2006-2012**



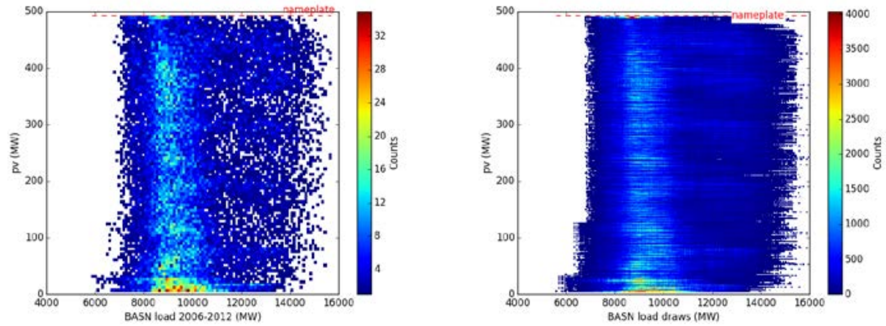
**Step 2. Use a daily energy matching function to produce hourly load data back to 1950.** For all years without hourly data (1980-2004), a normalized hourly shape is chosen from those years where hourly data is available (2005-2012) based on the closest match of total daily energy. Matched days are within 15 calendar days of each other so that seasonally specific diurnal trends are preserved. In addition, weekdays and weekends are matched separately. The chosen normalized daily shape is multiplied by daily energy to produce hourly profiles. This step yields an hourly profile for the weather record from 1980-2012 that is consistent with 2012 demographic and economic conditions.

**Step 3. Scale load shape to 2024 forecast levels.** The resulting 33 years of hourly load profiles are scaled to the expected 2022 energy and median annual peak load using a linear transformation. The result of this step is an hourly profile for the weather record from 1980-2012 that is consistent with the forecast level of demand in the 2024 Common Case.

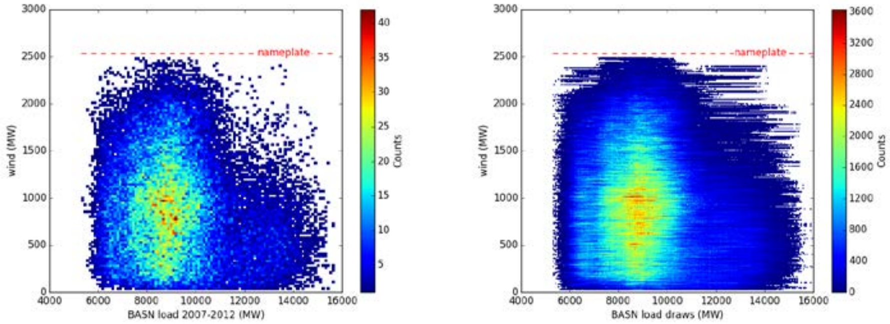
## 8.3 Results of Draw Methodology

Figure 37. Frequency of load & renewable pairings for Common Case portfolio, Basin region.

(a) Load & solar PV, hist (2007-2012)    (b) Load & solar PV, simulated draws



(c) Load & wind, hist (2007-2012)    (d) Load & wind, simulated draws



(e) Load & total VG, hist (2007-2012)    (f) Load & total VG, simulated draws

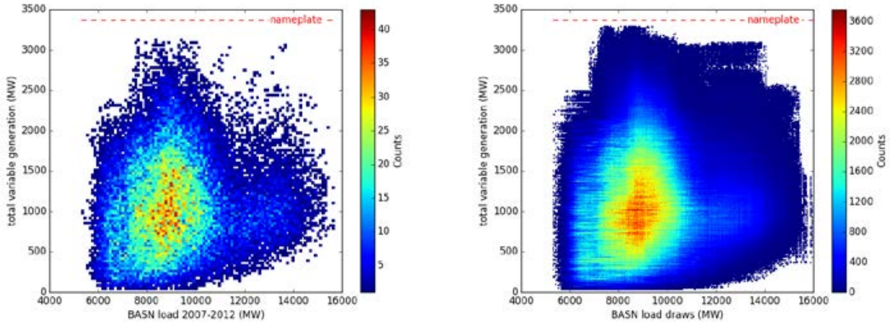
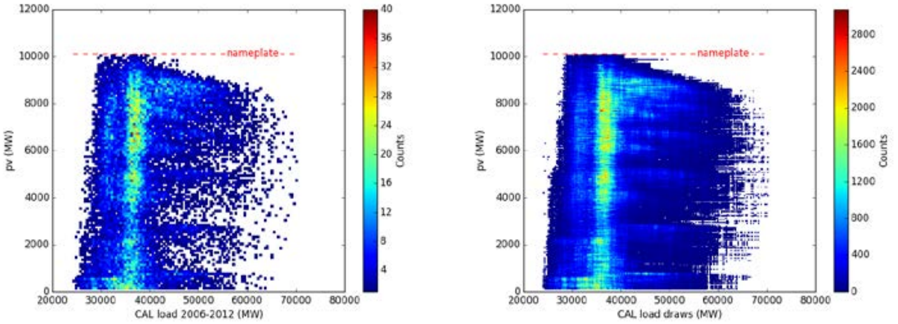
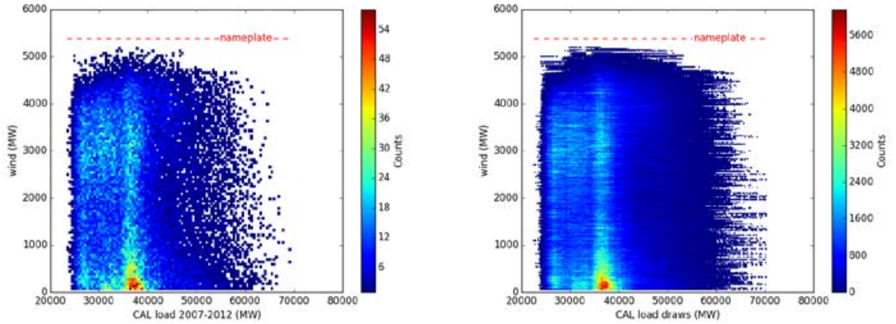


**Figure 38. Frequency of load & renewable pairings for Common Case portfolio, California region.**

**(a) Load & solar PV, hist (2007-2012)** **(b) Load & solar PV, simulated draws**



**(c) Load & wind, hist (2007-2012)** **(d) Load & wind, simulated draws**



**(e) Load & total VG, hist (2007-2012)** **(f) Load & total VG, simulated draws**

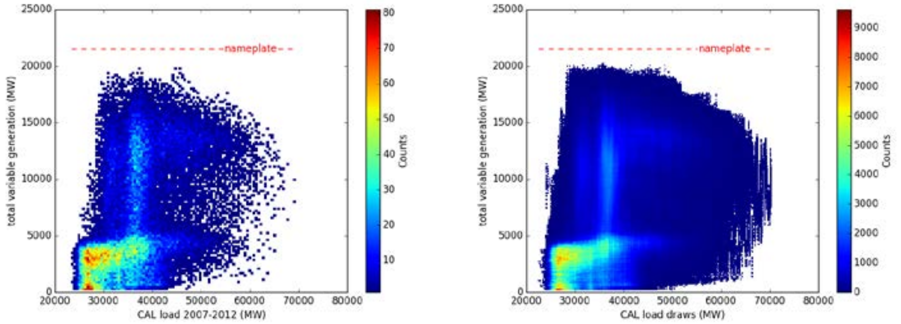
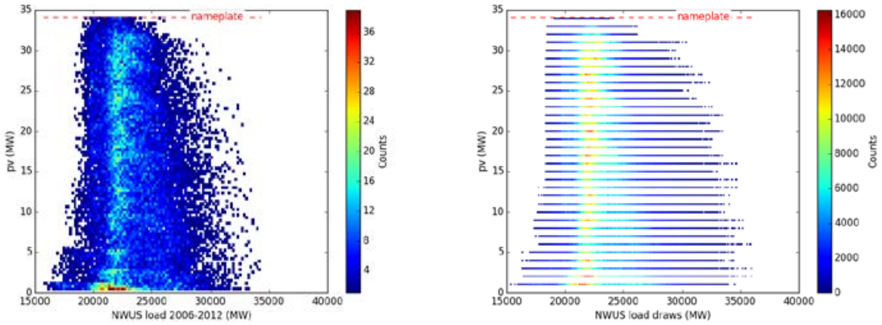
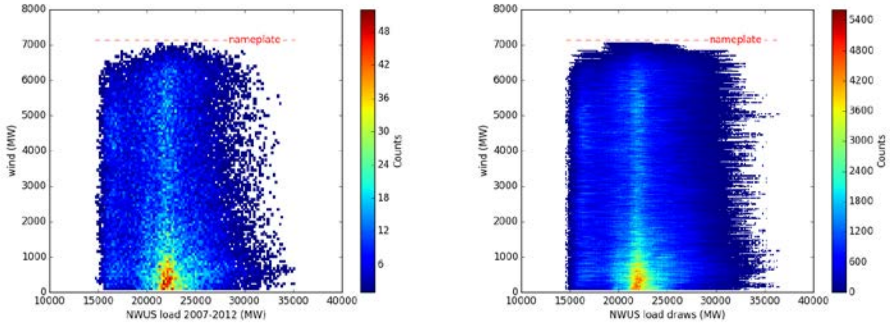


Figure 39. Frequency of load & renewable pairings for Common Case portfolio, Northwest region.

(a) Load & solar PV, hist (2007-2012) (b) Load & solar PV, simulated draws



(c) Load & wind, hist (2007-2012) (d) Load & wind, simulated draws



(e) Load & total VG, hist (2007-2012) (f) Load & total VG, simulated draws

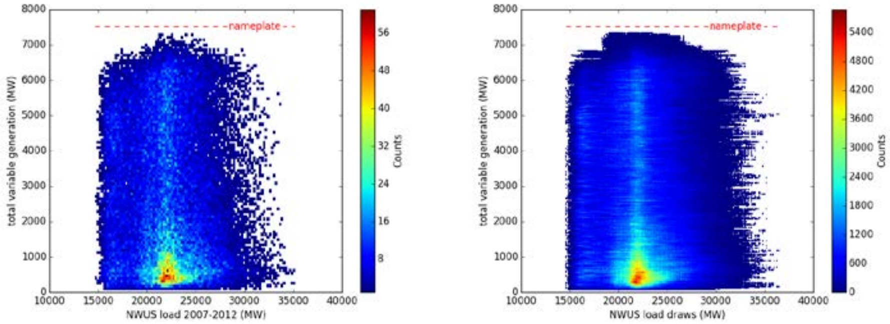
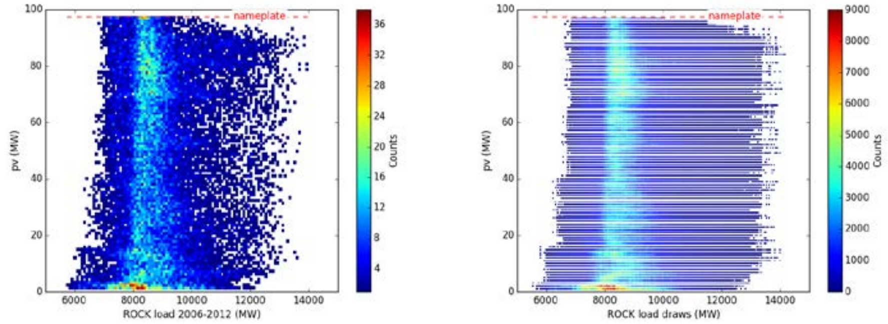
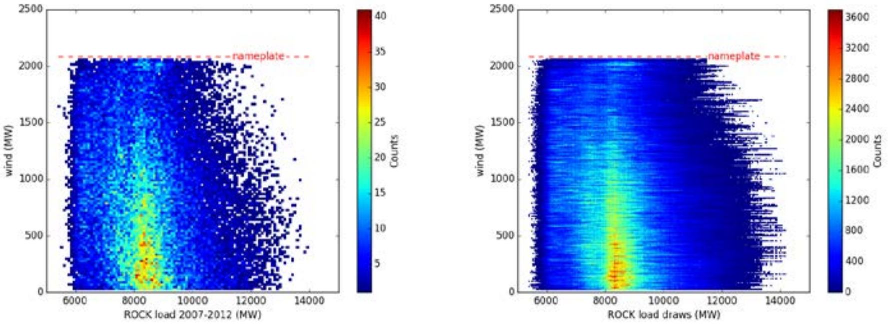


Figure 40. Frequency of load & renewable pairings for Common Case portfolio, Rockies region.



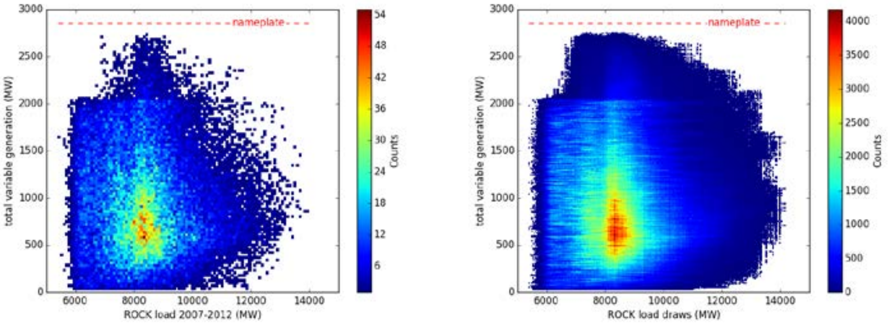
(a) Load & solar PV, hist (2007-2012)

(b) Load & solar PV, simulated draws



(c) Load & wind, hist (2007-2012)

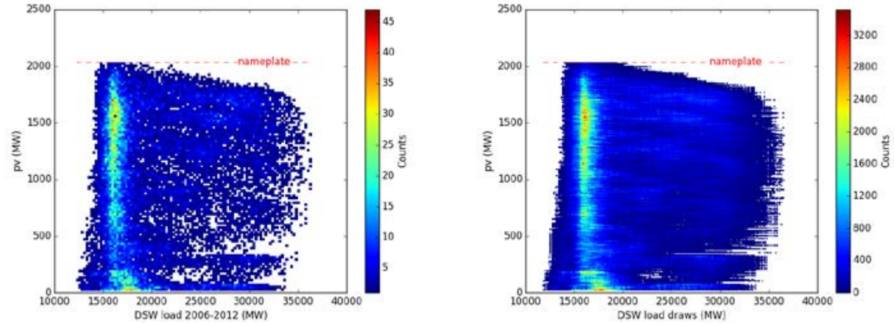
(d) Load & wind, simulated draws



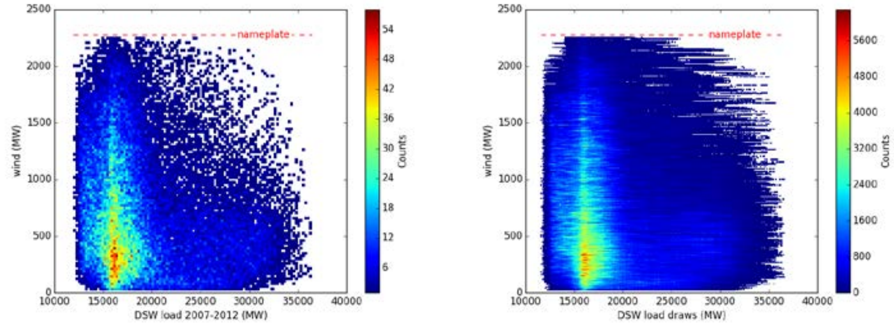
(e) Load & total VG, hist (2007-2012)

(f) Load & total VG, simulated draws

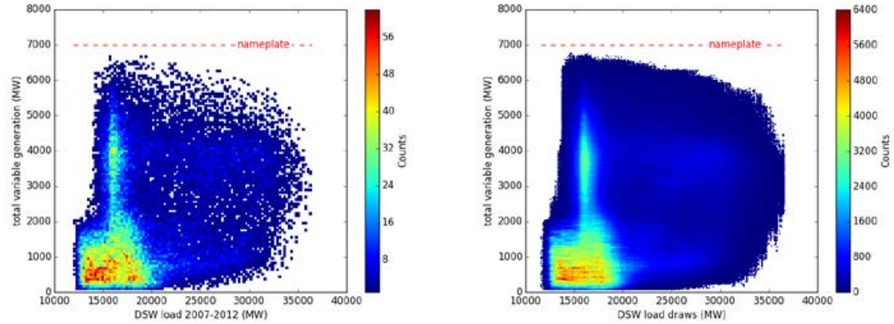
**Figure 41. Frequency of load & renewable pairings for Common Case portfolio, Southwest region.**



**(a) Load & solar PV, hist (2007-2012)** **(b) Load & solar PV, simulated draws**



**(c) Load & wind, hist (2007-2012)** **(d) Load & wind, simulated draws**



**(e) Load & total VG, hist (2007-2012)** **(f) Load & total VG, simulated draws**