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Western Interconnection Flexibility Assessment

Executive Summary

December 2015

NATIONAL RENEWABLE ENERGY LABORATORY

Energy+Environmental Economics

Western Interconnection Flexibility Assessment

Executive Summary

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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 Energy & Environmental Economics, Inc. (E3) and the National Renewable Energy Laboratory (NREL) to investigate these questions using advanced, stochastic reliability modeling and production cost modeling techniques. 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 Review Committee (TRC) comprising representatives from utilities, regulatory agencies, and industry throughout the Western Interconnection:

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

The TRC met a number of times throughout the course of the project to provide input and guidance on technical modeling decisions, to help interpret analysis, and to craft the study's ultimate findings and conclusions. The feedback of the TRC throughout the project was highly valuable to the project.

Executive Summary

Background

Over the past decade, the penetration of renewable generation in the Western Interconnection has grown rapidly: nearly 30,000 MW of renewable generation capacity—mostly solar and wind—have been built. By 2024, under current state policies, the total installed capacity of renewable generation in the Western Interconnection may exceed 60,000 MW. In front of this landscape of increasing renewable policy targets and declining renewable costs, interest in renewable generation and understanding its impacts on electric systems has surged recently. Regulators, utilities, and policymakers have begun to grapple with the potential need for power system "flexibility" to ensure reliable operations under high penetrations of renewable generation.

The Western Electricity Coordinating Council (WECC), in its role as the Regional Entity responsible for reliability in the Western Interconnection, is interested in understanding the long-term adequacy of the interconnected western grid to meet the new operational challenges posed by wind and solar generation across a range of plausible levels of penetration. WECC stakeholders have expressed a similar interest through study requests to examine high renewable futures that that implicate operational and flexibility concerns. The Western Interstate Energy Board (WIEB) seeks to understand these issues in order to inform policymakers about the implications of potential future policies targeting higher renewable penetrations.

With this motivation, WECC and WIEB collaborated to jointly sponsor this WECC Flexibility Assessment. The sponsors established three goals for this effort:

+ **Assess the ability of the fleet of resources in the Western Interconnection to accommodate high renewable penetrations while maintaining reliable operations.** Higher penetrations of renewable generation will test the flexibility of the electric systems of the West by requiring individual power plants to operate in fundamentally new ways, changing operating practices as well as the dynamics of wholesale power markets. This study aims to identify the major changes in operational patterns that may occur 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—for example, increased use of curtailment as an operational strategy and greater regional coordination in planning and operations—as well as physical changes to the electric system—new investments in flexible generating resources and the development of new demand side programs. This study examines how such measures can mitigate the challenges that arise with interconnection-wide increases in renewable penetration.
+ **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.

Assessment Methods

This study is organized into two sequential phases of analysis. The first phase, a resource adequacy assessment of the generation fleet, uses traditional loss-of-load-probability techniques to ensure that the electric system adheres to a traditional "one-day-in-ten-year" planning standard for loss of load. The second phase, the flexibility assessment, uses stochastic production cost analysis to examine the degree to which operational challenges are encountered with the additional of renewables to the system. By nesting the flexibility assessment within a traditional study of resource adequacy, the approach used in this study seeks to ensure that any challenges encountered in operations can be attributed to a lack of flexibility and are not simply the result of a system whose available capacity is inadequate to meet its peak demands.

The first phase of the analysis uses E3's **Renewable Energy Capacity Planning (RECAP)** model, a loss-of-load probability (LOLP) model designed to evaluate resource adequacy under high renewable penetrations. The RECAP analysis confirmed that the modeled resources across the study area were capable of meeting or exceeding the traditional one-in-ten loss of load frequency standard.[1] The second phase uses the **Renewable Energy Flexibility (REFLEX)** model for **PLEXOS for Power Systems**—an adaptation of traditional production cost modeling that incorporates principles from more traditional reliability analysis—to examine the impacts of high penetrations of renewable generation on the operations of these resources. Production simulation models are used for a variety of purposes, but the approach taken in this study has been tailored directly to the examination of flexibility challenges under high renewable penetrations.

While loss-of-load probability modeling is the de facto standard method for assessing conventional capacity adequacy, there is no analogous industry-standard approach for assessing the adequacy of flexibility in an electric system. A number of approaches have been explored, and a variety of metrics have been proposed as a means of measuring flexibility adequacy—for instance, "Expected Unserved Ramp."[2] While these metrics may be useful as *indicators* of power system inflexibility, they are not directly actionable because there is no standard for unserved ramping that power systems are required to meet. Rather than attempting to define a new metric, the REFLEX production cost modeling approach used in this study is designed to measure the *consequences* of inadequate flexibility, thereby illustrating a method through which actionable information can be provided to planners and decision-makers.

[1] The results of the Phase 1 analysis, summarized in the body of this report, were also published as a standalone report available at: **http://westernenergyboard.org/wp-content/uploads/2015/06/04-2015-WECC-WIEB-Flexibility-Assessment-Report-Interim.pdf**

[2] See, for example, EPRI's "Power System Flexibility Metrics: Framework, Software Tool and Case Study for Considering Power System Flexibility in Planning," available at: **http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?productId=000000003002000331**.

In traditional LOLP analysis, the consequence of inadequate capacity is straightforward: the system is incapable of simultaneously meeting all loads, so some loads cannot be served. This is measured using conventional metrics such as LOLP, Loss of Load Expectation (LOLE), and Expected Unserved Energy (EUE). Inadequate flexibility can also lead to loss of load, even for systems that would otherwise be resource adequate. For example, if a large portion of the thermal fleet is cycled off to accommodate high output from renewable generators, the system might not have adequate resources committed to meet a large upward net load ramp (this is illustrated in Figure 1a). REFLEX therefore tracks EUE as one measure of power system inflexibility.

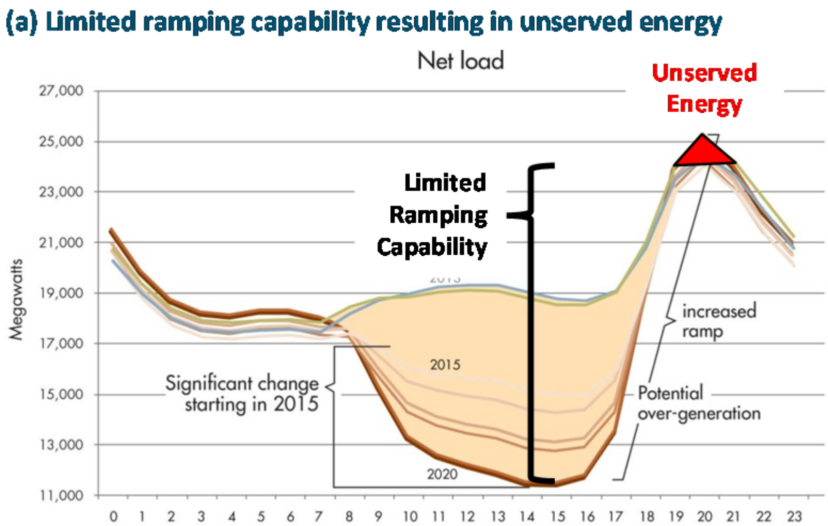
However, loss of load can be avoided through prospective curtailment of renewable generation to ensure that the thermal resources required to maintain reliability can remain online. This is illustrated in Figure 1b, where renewable generation is curtailed during the mid-afternoon in order to ensure that the system has sufficient operating capability to meet the evening ramp. In this way renewable curtailment is both a key operational strategy in flexibility-constrained systems and is also the primary consequence of inadequate flexibility.

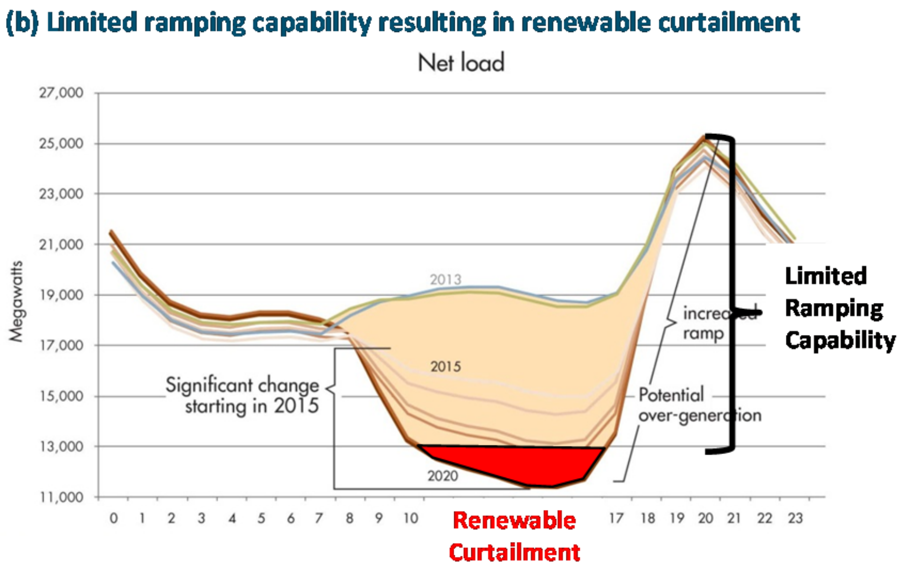
Because the system operator has a choice between curtailing renewables and curtailing loads, it needs a method for determining which strategy to use on a given day. Additional information is therefore needed about the economic consequences of unserved energy and curtailed renewables. This information may come through market-based bids provided by loads and renewable project operators. In the absence of market information, deemed values are used based on available literature.

Studies typically, ascribe a high value of between $10,000 and $100,000/MWh of lost load. In contrast, the cost of renewable curtailment is effectively smaller by orders of magnitude. Out-of-pocket costs of curtailment include O&M costs as well as any lost production tax credits. In addition, under a production quota such as an RPS, curtailed renewable generation must typically be replaced like-for-like in order to ensure compliance. Thus, the cost of curtailment is determined by the "replacement cost" of renewable generation (the cost of procuring an additional MWh of generation to "replace" the curtailed energy).

In this study, the penalty prices assumed for loss of load and renewable curtailment are **$50,000** and **$100/MWh**, respectively. The asymmetry between these penalties ensures that REFLEX will steer the system away from loss of load if at all possible, allowing some amount of curtailment when necessary to ensure that the system has adequate operating flexibility. In this respect, renewable curtailment serves as the "default solution" for system operators facing flexibility constraints, the relief valve with which an operator can ensure the electric system remains within an operable range.

Figure 1. Tradeoff between upward and downward flexibility challenges





In order to capture an adequately broad sample of operating conditions and possible flexibility constraints using this framework, this study uses Monte Carlo sampling of load, wind, solar, and hydro across a wide range of historical conditions. Production cost model are typically used to analyze a single "typical" year with its unique set of load, wind, solar, and hydro profiles. This study makes use of much longer historical records for each of these variables, as summarized in Figure 2. Inputs for these variables are derived from a variety of sources: load shapes based on historical weather conditions spanning a thirty-year period are created using a neural network regression model; wind and solar profiles are derived from NREL's WIND and SIND Toolkits, respectively; and hydro data is based on a combination of actual and simulated historical data for Western hydro systems obtained from the Energy Information Administration (EIA) and the Northwest Power and Conservation Council (NWPCC). Profiles from different periods are combined using a stratified sampling methodology to produce Monte Carlo "day draws" for production cost modeling. By adapting a technique that has historically been used in LOLP analyses, this approach captures a more robust distribution of expected long-run conditions than any single historical year.

Figure 2. Historical conditions incorporated into draws

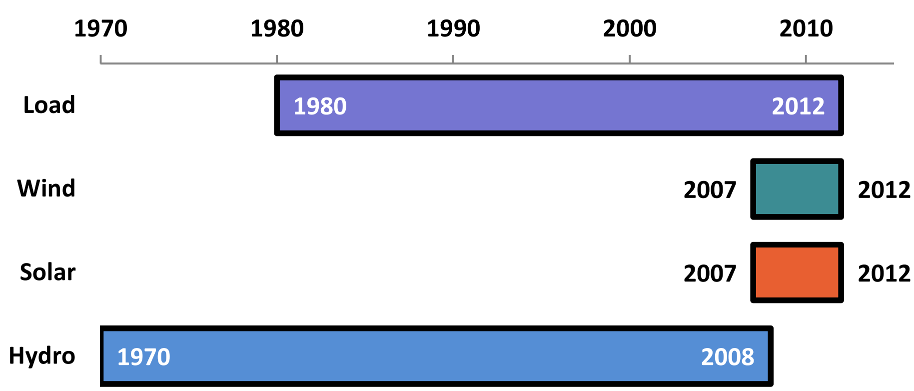
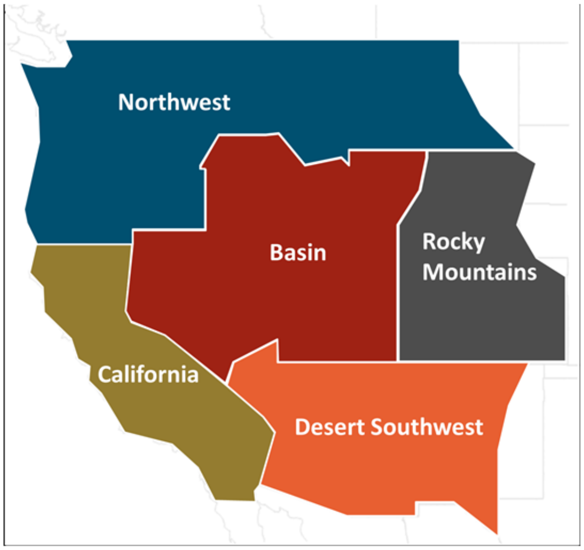


Figure 3. Regions included in analysis.



The analytical framework described above is used to evaluate the flexibility of five regions within Western Interconnection, shown in Figure 3. Each region represents a portion of the Western Interconnection with relatively homogeneous loads and resources, some existing degree of coordination in resource planning and/or operations, and limited internal transmission constraints.[3] In the study, each region is linked to its neighbors with a zonal transmission model. One of the key simplifying assumptions of this approach is that each region is perfectly coordinated in operations internally, effectively pools all of its generation resources to balance net load without regard for existing contracts, ownership, or operational conventions.

[3] The Alberta Electric System Operator (AESO) and BC Hydro (BCH) are excluded from this analysis due to lack of data availability; their exclusion from the study may overstate the magnitude of flexibility challenges, particularly if the flexibility of the hydro system in British Columbia could be used to facilitate renewable integration

This study begins with a conservative assumption that exchange between any two regions is limited to the range that has been observed historically rather than the full physical capability of the transmission system that links them. This approach serves three purposes: (1) it serves as a proxy for the many institutional constraints that exist in today's system, in which power exchange between regions generally occurs on a limited and bilateral basis; (2) it helps to isolate the renewable integration challenge in each region in order to characterize each fleet's ability to integrate its own renewable portfolio rather than relying on the flexibility and diversity of the entire Western system; and (3) it provides a useful counterfactual to a scenario in which limits on the transmission system are relaxed to their full physical capability, allowing this study to highlight the value that could be achieved through centralized dispatch of all resources in the WECC region.[4]

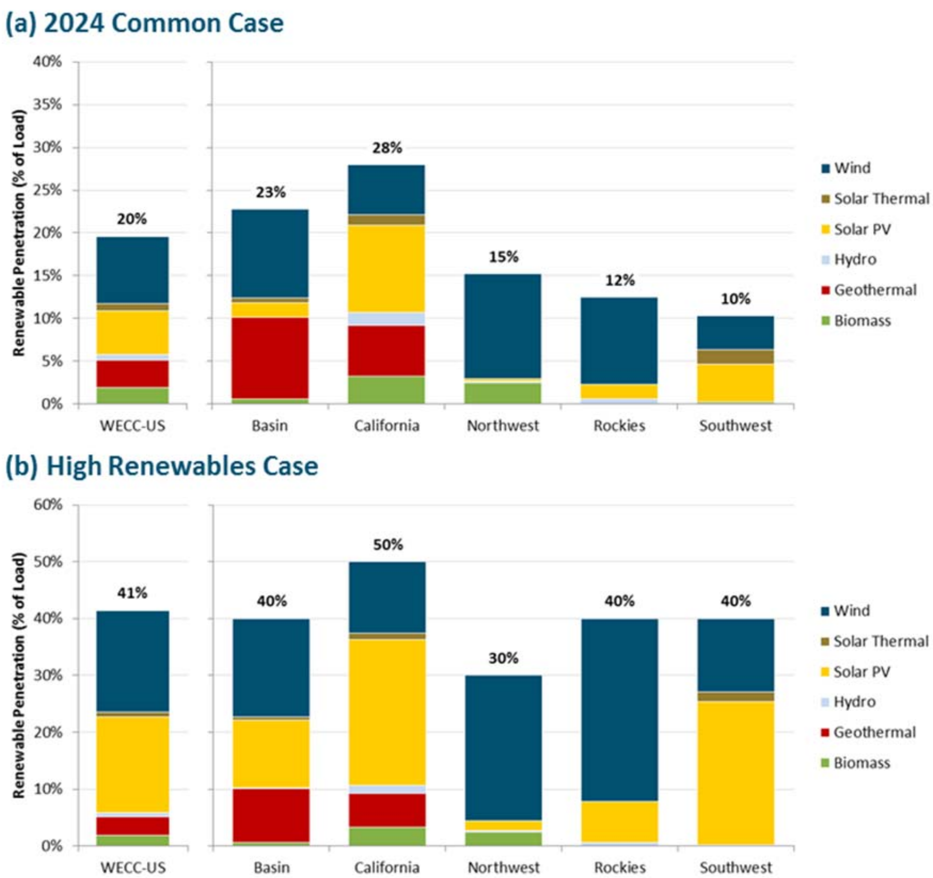
Two renewable portfolios are examined within the flexibility assessment for each region. The first, shown in Figure 4a, is based on the 2024 Common Case developed by WECC's Transmission Expansion Planning Policy Committee (TEPPC) and represents a penetration of renewable generation that is largely consistent with state RPS targets current as of 2014;[5] analysis of this case

[4] Increased regional coordination is one of the integration "solutions" examined in this report, and this contrast provides the underlying method through which its value is characterized.

[5] At the time of the development of the 2024 Common Case database and the start of this study, California's RPS policy remained at 33%. With the increase to a 50% target by 2030, the Common Case is no longer indicative of current policy in that region but still provides a useful point of reference for its near-term relevance.

provides a means of validating the model as well as an indication of potential flexibility challenges that could emerge under existing policy. The second portfolio studied is a "High Renewables Case," whose composition is shown in Figure 4b. The penetrations chosen for study in the High Renewables Case were intentionally chosen to be high enough to cause significant changes in operations, and to ensure that flexibility challenges would result, allowing this study to characterize renewable integration challenges that may emerge above current policy levels.

Figure 4. Renewable portfolios analyzed in the flexibility assessment



Nature of Regional Renewable Integration Challenges

Because the penalty prices for unserved energy and curtailment prioritize load service over the delivery of renewable generation, renewable curtailment is the key indicator of a system that is constrained in its ability to integrate renewables. Curtailment can occur due to simple oversupply—where the generation available exceeds the load—or as a means to ensure reliable operations in the presence of dispatch flexibility constraints. REFLEX produces many metrics that are useful for understanding how high penetrations of renewables impact a system; however, this study uses renewable curtailment as the key indicator of flexibility constraints for each case.

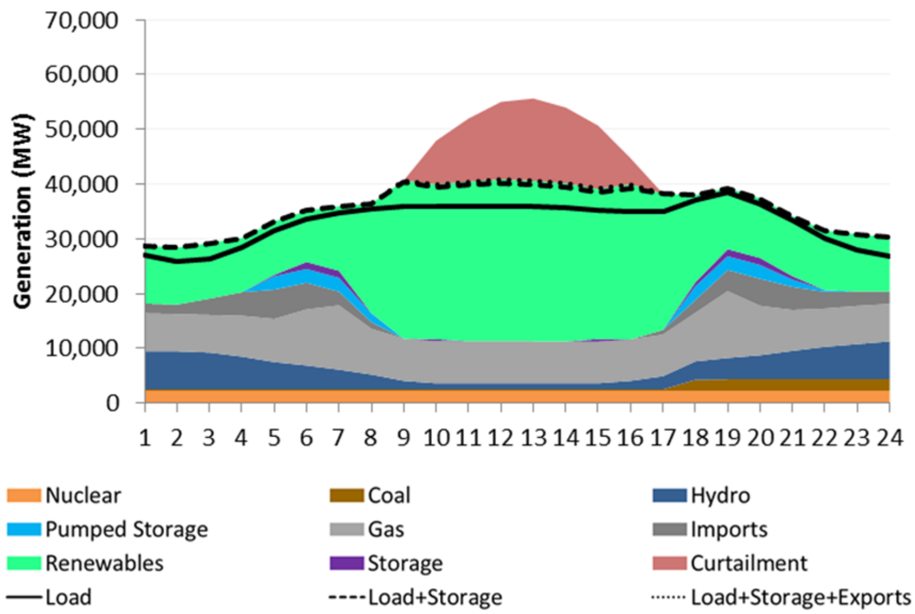
Table 1 summarizes the renewable curtailment observed in each region for the renewable portfolios examined. In the Common Case, the extent of renewable curtailment experienced across the Western Interconnection is limited—it constitutes less than 0.1% of the available renewable energy. In contrast, in the High Renewables Case, renewable curtailment appears routinely and represents a large share of the available renewable generation. The specific nature of the challenges differ across regions—each a unique result of the region's distinct renewable portfolio, the characteristics of its conventional generators, and the profile of its loads.

Table 1. Renewable curtailment observed in the Common Case and High Renewables Case (% of annual generation)

Scenario	Basin	California	Northwest	Rockies	Southwest	WECC-US
Common Case	0.01%	0.00%	0.06%	0.13%	0.00%	0.02%
High Ren Case	0.4%	**8.7%**	**5.6%**	0.6%	**7.3%**	**6.4%**

In the High Renewables Case, renewable curtailment is most prevalent in California and is driven by a phenomenon that has been well-characterized in past studies of renewable integration: because solar PV resources produce only during daylight hours, a large share of the generation in California's renewable portfolio is concentrated in the middle of the day. The high daytime renewable production exerts pressure on the non-renewable fleet to reduce its output to low levels, but non-renewable generation is limited in its ability to do so by inflexibility (especially for must-run resources like nuclear & cogeneration), minimum generation constraints, and the need to carry contingency and flexibility reserves. The result of this dynamic is a regular daily pattern of midday renewable curtailment illustrated in Figure 5, which shows a typical spring day in California in the High Renewables Case.

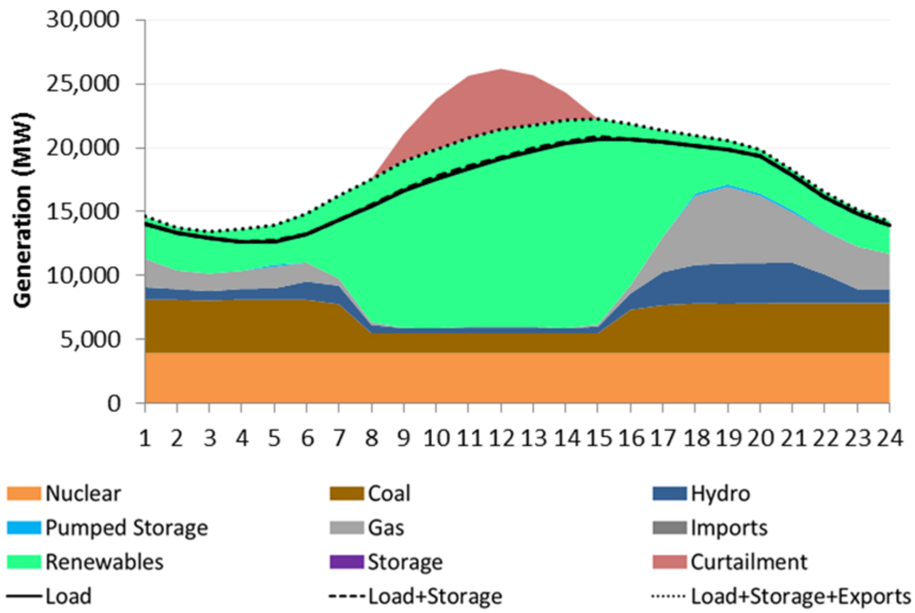
Figure 5. Typical spring day, California, High Renewables Case[6]



The Southwest also experiences a large volume of renewable curtailment in the High Renewables Case. Much like California, the Southwest relies heavily on solar PV resources in the High Renewables Case and, as a result, experiences a similar diurnal oversupply phenomenon. Figure 6 presents a typical spring day in the Southwest in which many of the same elements that characterize the California challenge are apparent: large diurnal net load ramps that coincide with sunrise and sunset and a mid-day period of renewable curtailment when all dispatchable resources have been reduced to their lowest output.

[6] Note that this study reports all results in Pacific Standard Time; all plots that show hourly results use the PST convention.

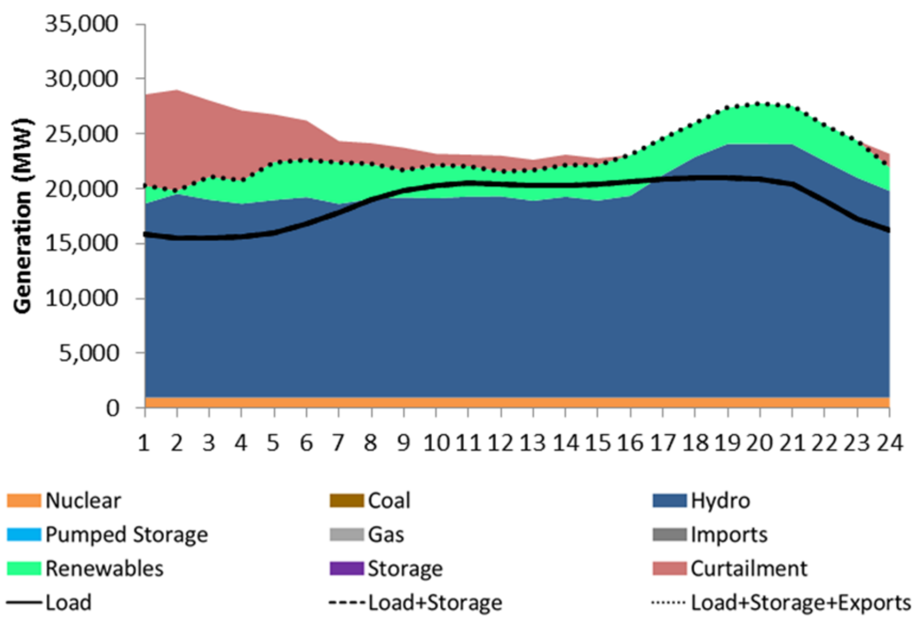
Figure 6. Typical spring day, Southwest, High Renewables Case



Notwithstanding these similarities, the Southwest does have an important distinguishing characteristic from California: its reliance on coal generation for a large share of its installed capacity. Historically, the coal fleet in this region has operated largely in a baseload capacity, ramping and cycling with limited frequency. The ability to operate the coal fleet more flexibly during high renewable output days is a key strategy to facilitate renewable integration in the Southwest and in other regions that rely on coal generation today.

The third region that experiences significant quantities of renewable curtailment in the High Renewables Case is the Northwest; though oversupply is its primary cause, the nature of the oversupply is entirely unique to that region. The Northwest is characterized by its large hydroelectric fleet, and during the spring runoff season, during average and wet hydro years, the Northwest hydro system is capable of meeting most or all of the Northwest's energy needs on a day-to-day basis. Adding wind generation to that system during that time of year results in an excess supply of zero-marginal-cost generation. Such oversupply events have already been experienced in parts of the Northwest in 2010-2012 when surplus hydro conditions, combined with dispatch inflexibility, led to wind curtailment.[7] With the addition of large amounts of wind generation in the High Renewables Case, the oversupply during the spring runoff is intensified. An example of such a day is shown in Figure 7.

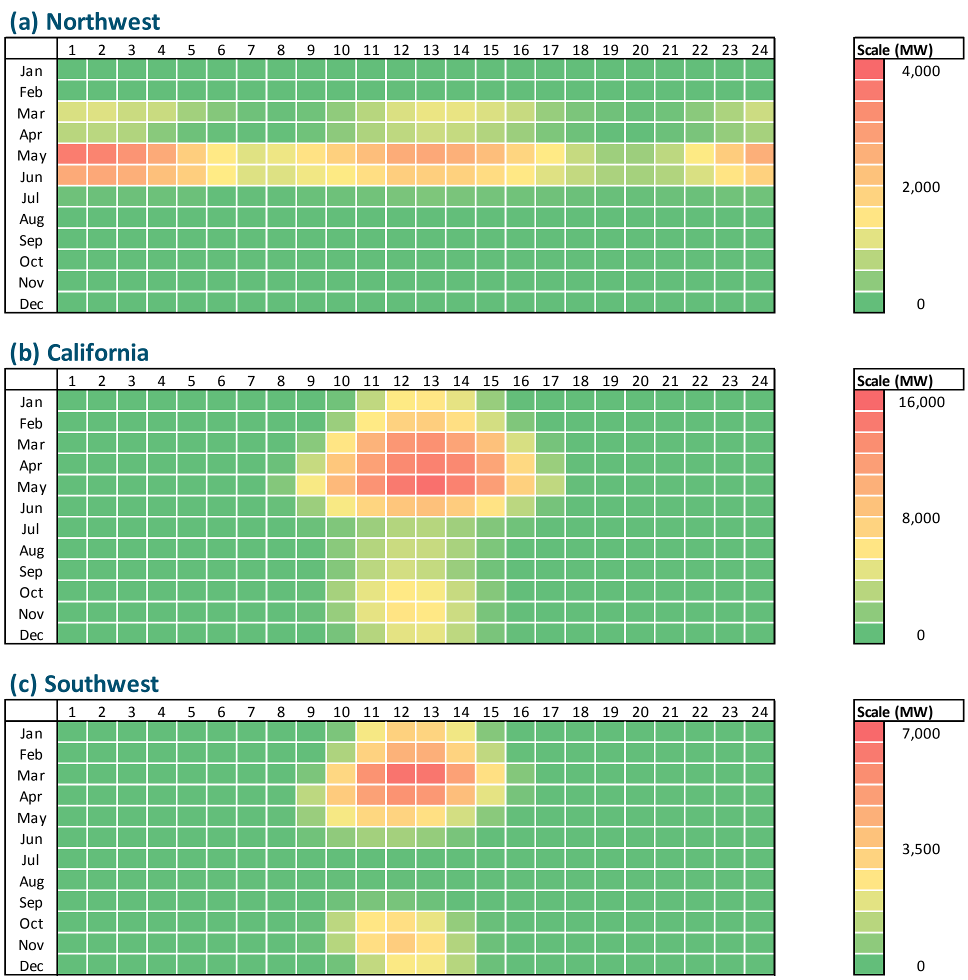
Figure 7. Typical spring day, Northwest, High Renewables Case



[7] In recognition of this phenomenon, the Bonneville Power Administration (BPA) has developed an "Oversupply Management Protocol" to allow for prudent management of generation resources during oversupply conditions.

Spring days are chosen to highlight flexibility challenges because the spring months (March through June) represent the most challenging periods for renewable integration throughout the West. The combination of relatively low loads, high hydro system output, and high renewable output results in a concentration of oversupply during this period of the year. Figure 8 illustrates the diurnal and seasonal trends in renewable curtailment for these three regions through heat maps that display the average amount of renewable curtailment in each month-hour. The similarities between California and the Southwest are immediately evident: throughout the year, curtailment is concentrated in the middle of the day, driven by the solar PV oversupply in each region. This oversupply is greatest in the spring and smallest in the summer, when each region's loads are highest due to high cooling loads and can absorb higher quantities of solar PV output. The seasonal trend in the Northwest, by contrast, is more closely linked to the spring runoff from the hydro system and its interaction with a wind-heavy renewable fleet, which leads to renewable curtailment at all hours in the spring but is most concentrated at night when wind output is high and loads are low.

Figure 8. Seasonal and diurnal patterns of renewable curtailment, High Renewables Case

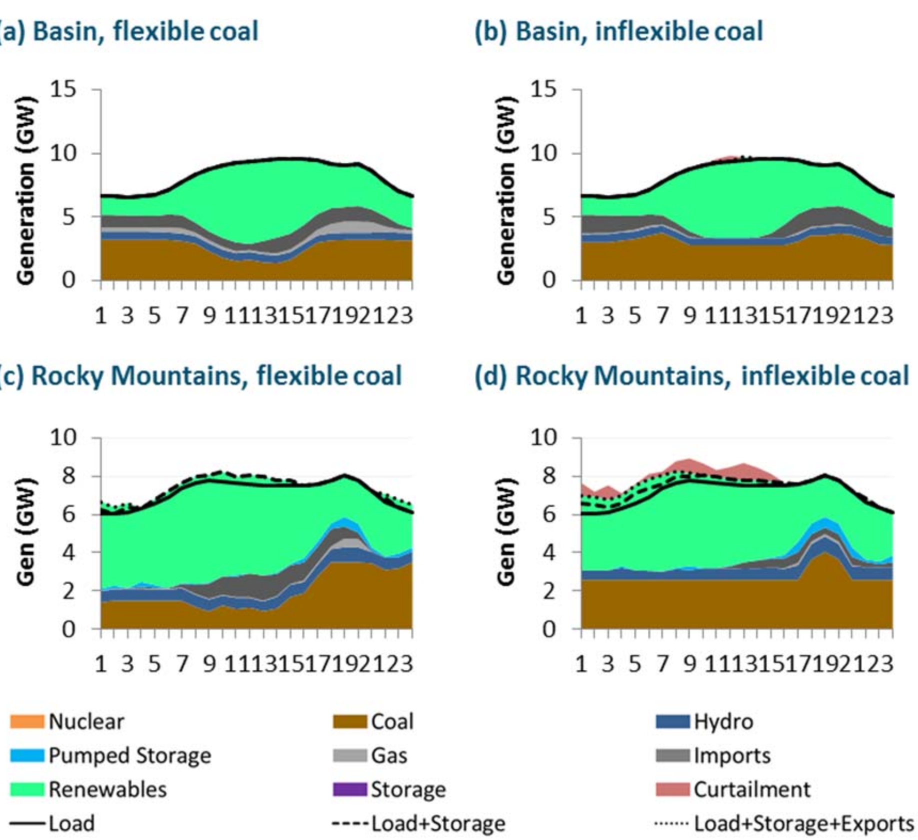


The dramatic increase in curtailment observed in these three regions between the Common Case and the High Renewables Case is indicative of a phenomenon that is highly nonlinear. In the absence of mitigation measures, curtailment grows at an increasing rate as renewable penetration climbs. For example, the marginal curtailment for a new solar PV resource (i.e. the next solar resource built on top of the portfolios described here) in California is between 50-60%—that is, in excess of half of its available energy would not be able to be delivered to the California system—a figure substantially higher than the average curtailment of 9%.

In contrast to California and the Northwest and Southwest regions, curtailment is observed in much lower quantities in both the Basin and Rocky Mountain regions. What distinguishes the Basin and Rocky Mountain regions from California and the Southwest—all four fleets rely primarily on dispatchable thermal resources to serve net load—is the amount of diversity assumed in their renewable portfolios. Whereas the concentration of solar PV during the middle of the day drives the oversupply phenomenon in California and the Southwest, production is far less concentrated during specific periods of the year in the Basin and Rocky Mountain regions. In the Basin, this is a result of technological diversity that combines geothermal, solar and wind resources; in the Rocky Mountains, it is the result of a portfolio comprising primarily wind resources whose scale and geographic dispersion result in production spread throughout the year.

While curtailment is observed in limited quantities in these regions, both the Rocky Mountains and the Basin region show dramatic changes in how the generation fleets operate to balance higher penetrations of renewable generation. A key driver of the magnitude of operational challenges in these two regions is the extent of the ability of thermal generators to ramp and cycle. Historically, coal generators have operated as baseload resources, running at high capacity factors throughout the year. Higher penetrations of renewable generation will exert pressure on operators to use these units more flexibly than they have historically; however, there are technical, economic, and institutional factors that might limit their ability to do so. The amount of flexibility that can be harvested from the aging coal fleet is uncertain and deserves further attention, but its implications for renewable integration are clear: an electric system with coal generators whose flexibility is limited in day-to-day operations will experience renewable curtailment in larger quantities and more frequently than one in which coal generation operates flexibly. This tradeoff is illustrated for both the Basin and Rocky Mountain regions in Figure 9.

Figure 9. Typical spring days, Basin and Rocky Mountains, High Renewables Case (with and without limits on coal flexibility)



Enabling Strategies for Renewable Integration

This study treats renewable curtailment as the “default solution” to flexibility challenges as it represents a last recourse for system operators—prior to shedding load—once the flexibility of the existing traditional dispatchable system has been exhausted. However, there are many options for alternative strategies that, if identified and deployed in advance, can provide operators with additional flexibility and mitigate the need to curtail renewable generation. These “solutions” include improvements in scheduling and dispatch, investments in new flexible generation, and new demand-side programs. Investigating the full potential list of integration solutions is beyond the scope of this study; the solutions chosen for study herein are intended to help illustrate the types of attributes that flexibility planners may wish to consider. This study considers three specific measures to facilitate renewable integration:

+ Increased regional coordination;
+ Investments in energy storage technologies; and
+ Investments in flexible gas generation.

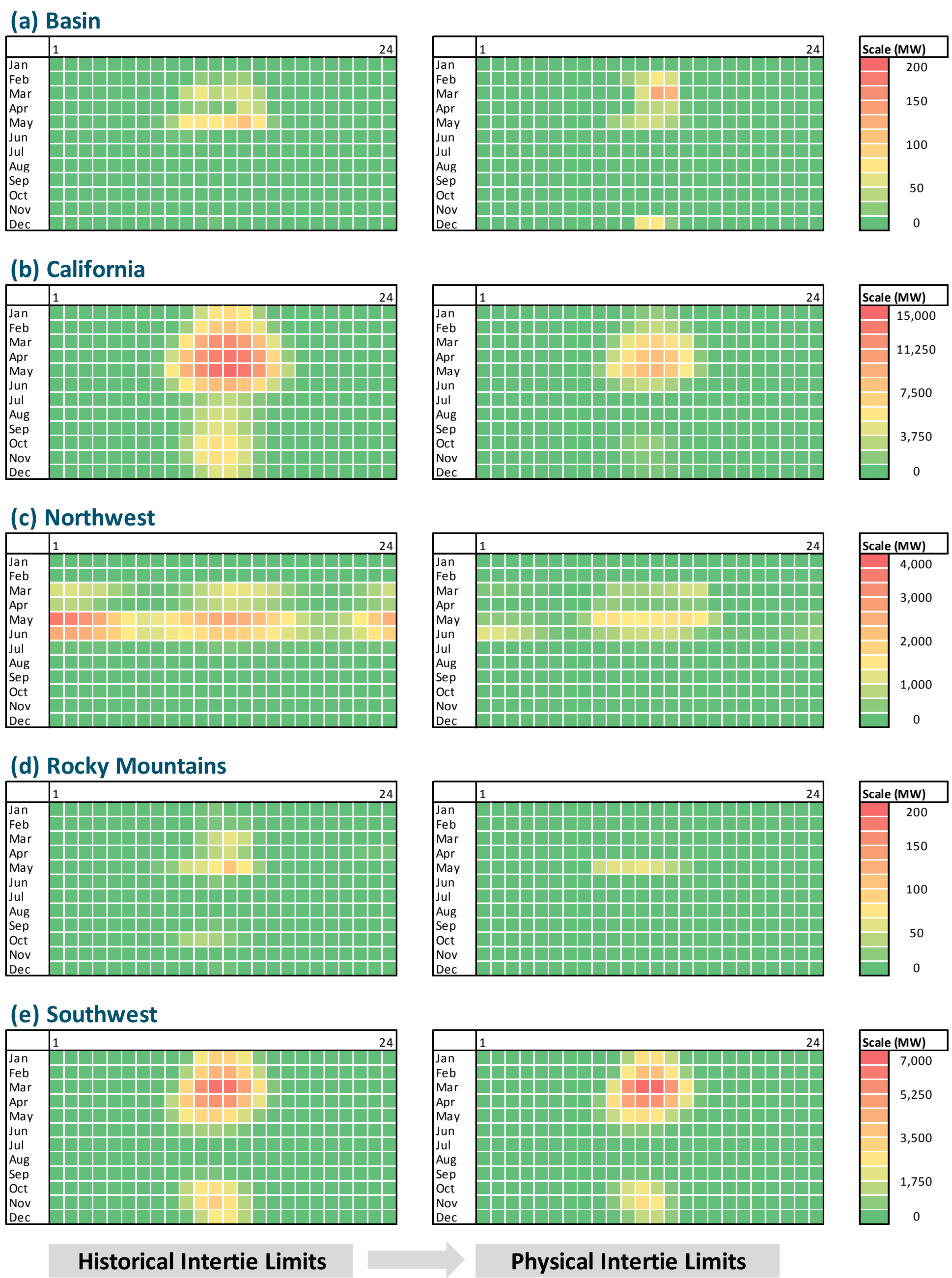
The first among these—improving regional coordination in operations—represents an institutional improvement to facilitate renewable integration. Historically, the balkanized Western Interconnection has operated largely according to long-term contractual agreements and through bilateral power exchange. “Regional coordination” could represent a step as incremental as improving upon existing scheduling processes or as comprehensive as the consolidation of the Western Interconnection under a single centralized operator. This study does not presume the mechanism through which coordination occurs, but demonstrates the value of achieving full coordination by contrasting a future in which interregional exchange is limited to the historical range with one in which it is limited by the ratings of interregional transmission paths, allowing fuller utilization of load and resource diversity.

Relaxing the constraint on interregional exchange to allow the use of the transmission system to its physical limits results in a reduction of renewable curtailment from 6.4% to 3.0% (see Table 2). A significant share of this value is derived from regions that, facing an oversupply condition that might otherwise require renewable curtailment, are able to use the full capability of the transmission system to find an alternative market for their power. This impact is shown in Figure 10. The reduction of curtailment is largest in California—which is both electrically and institutionally close to a market in the Northwest that can accommodate midday exports outside of the spring season—and in the Northwest—whose nighttime oversupply finds a destination in both California and the Southwest markets. Notably, the observed impact on the Southwest is lower than in the prior two regions, as connections with the Basin and Rocky Mountains provide it with limited export markets and California's frequent simultaneous oversupply makes it an impractical market for solar surplus.

Table 2. Comparison of regional renewable curtailment with historical and physical intertie limits imposed, High Renewables Case

Scenario	Basin	California	Northwest	Rockies	Southwest
Historical Intertie Limits	0.4%	8.6%	6.1%	0.1%	7.3%
Physical Intertie Limits	0.5%	3.1%	1.6%	0.5%	6.0%
Difference	**+0.1%**	**-5.6%**	**-4.5%**	**-0.0%**	**-1.3%**

Figure 10. Impact of increased regional coordination upon seasonal curtailment patterns.



While desirable from a technical and economic perspective, harvesting the full diversity of the Western Interconnection through coordination of operations to integrate renewable generation presents a significant institutional challenge. Individual utilities, balancing authorities, and planning entities may be justified in examining potential investments or demand-side programs to provide greater local or regional operational flexibility. To examine the potential flexibility benefits of investments in new flexible resources, 6,000 MW of energy storage[8] and new fast-starting, fast-ramping gas CCGTs are added to the High Renewables Case in separate scenarios to quantify their impact on operations.[9] The impact of each additional resource on renewable curtailment is summarized in Table 3.

Table 3. Impacts of new investments on regional renewable curtailment, High Renewables Case.

Scenario	Basin	California	Northwest	Rockies	Southwest
Reference Grid	0.4%	8.7%	5.6%	0.6%	7.3%
+6,000 MW Storage (2hr)	0.4%	7.2%	5.7%	0.6%	6.2%
+6,000 MW Storage (6hr)	0.4%	5.8%	5.8%	0.6%	5.1%
+6,000 MW Storage (12hr)	0.4%	5.8%	5.7%	0.6%	5.1%
+6,000 MW Flex CCGT	0.4%	8.7%	5.6%	0.6%	7.3%

The primary result this analysis indicates is that the addition of new "downward" flexibility (e.g. the ability to charge energy storage) provides substantially greater benefits than the addition of new "upward" flexibility (e.g.

[8] Multiple durations of energy storage resources were modeled, including 2-hr, 6-hr, and 12-hr.
[9] In each scenario, 4,000 MW of the candidate resource was located in California and 1,000 MW was located in both the Northwest and the Southwest. The choice of where to add storage was made on the basis of where the largest flexibility challenges were identified.

the ability to ramp from Pmin to Pmax very quickly), as it expands the net load range across which a system can operate. This analysis indicates several findings on the impacts of new flexibility investments:

- Energy storage provides a clear benefit through curtailment mitigation in the Southwest and California. This is largely due to the fact that each region's diurnal solar oversupply allows storage resources to cycle almost daily, charging during the middle of the day during curtailment hours and discharging in the early morning and/or evening to help meet solar-driven net load ramps.
- The value of energy storage in the Northwest is limited by comparison. Here, where oversupply events during the spring runoff persist much longer, often throughout the day, there is a much more limited opportunity to shift generation within the day.[10] Also, the Northwest already has significant intra-day energy storage capability through its existing system of hydroelectric resources.
- In all regions where new flexible gas CCGT capacity is added, the impact is minimal. While further study is needed, it appears that all regions have sufficient upward ramping capability in the base system. These new, efficient gas resources may reduce system *cost* due to their efficiency, but they do little to reduce curtailment because they do not appreciably improve the system-wide ratio of minimum to maximum generation capability.

[10] Note that the REFLEX approach of using day draws likely understates the value of storage in the Northwest, as it does not capture value that could be provided through inter-day charging and discharging patterns.

While the general findings of these cases help to illustrate the attributes of new flexible resources that provide significant benefits, the limitations of their applicability must also be understood:

- One of the underlying assumptions of the regional approach is that each constituent utility and balancing authority of a region makes its resources fully available for optimal dispatch within that region. However, this assumption is optimistic for today's electric system—one that is dominated by bilateral transactions—and findings that apply to a wholly optimized region may not be applicable to individual entities within it.
- The starting case to which the flexible resources are added assumes a significant degree of flexibility in the existing thermal system. Production simulation models typically do not consider increased O&M costs incurred as units are asked to cycle more frequently. As the sensitivity on coal flexibility demonstrates, there is value to a system that can operate its thermal units flexibly (i.e. can reduce their output to very low levels or turn off), and to the extent that technical, economic, or institutional factors prevent the coal fleet from operating as this study assumes, additional flexible thermal generation could have more value than this study identifies.
- A critical qualifier for this analysis is that each regional fleet already meets traditional resource adequacy needs prior to the addition of incremental flexible capacity. While the value of flexibility alone may not be enough to justify procuring a specific resource, entities should carefully consider the benefits that additional flexibility could provide when new system capacity is needed due to load growth, retirement of aging coal generation, or other factors.

Implications and Next Steps

The technical findings and conclusions reached through this study have a number of implications that are relevant for regulators and policymakers seeking to enable higher penetrations of renewable generation on the system and to ease the associated challenges.

1. The analysis conducted in this study identifies no technical barriers to the achievement penetrations of renewable generation of up to 40% of total supply in the Western Interconnection.

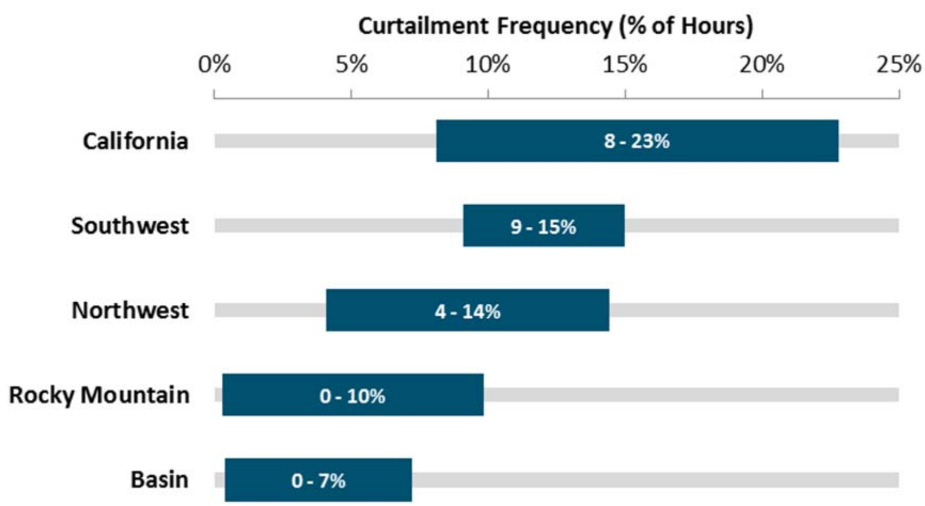
In both the Common Case and the High Renewables Case, the flexibility assessment demonstrates capability of the electric system of the Western Interconnection to serve loads across a diverse range of system conditions. Further, no "need" for additional flexible capacity beyond existing and planned resources is identified in either case. Examination of issues relating to stability, adequacy of frequency response, and the potential impact of major contingencies is beyond the scope of this study; however, other studies to examine these topics are have come to similar conclusions regarding the technical feasibility of integrating high penetrations of renewable generation.[11]

What does distinguish the High Renewables Case from the Common Case is the significant quantity of renewable curtailment observed. At relatively low penetrations, renewable generation can be integrated into the system

[11] See the Western Wind and Solar Integration Study – Phase 3 (NREL & GE), available at: http://www.nrel.gov/electricity/transmission/western-wind-3.html

effectively with limited curtailment; however, once a region's penetration surpasses a certain threshold, curtailment occurs with increasing frequency. Renewable curtailment is characteristic of all of the High Renewables scenarios investigated: Figure 11 summarizes the range of curtailment frequency across all of these scenarios.

Figure 11. Observed range of hourly curtailment frequency across all High Renewables scenarios in each region.



2. Routine, automated renewable curtailment is a fundamental necessity to electric systems at high renewable penetrations, as it provides operators with a relief valve to manage net load conditions to ensure a system can be operated reliably at increasing penetrations.

Historically, the idea of "curtailment" has had negative connotations, but at high penetrations of renewable generation, it is a fundamental necessity.

Notwithstanding its cost to ratepayers, renewable curtailment provides operators with a tool with which to manage the net load to ensure reliable service when the flexibility of all other existing resources has been exhausted; in this respect, it serves as the “default solution” for a system constrained on flexibility.

The role of curtailment in the operations of an electric system at high renewable penetrations is multifaceted. In addition to allowing operators to mitigate oversupply events when generation would otherwise exceed loads, renewable curtailment can be used to mitigate the size of net load ramps across one or more hours, to adjust for forecast error between day-ahead and other scheduling processes, and to substitute for traditional flexibility reserve services (including regulation).

Because of the crucial role of renewable curtailment in operating electric systems at high penetrations of renewables, ensuring that curtailment is available and can be used efficiently in day-to-day operations requires a number of steps:

+ **Market structures and scheduling processes must be organized to allow participation by renewable generators.** Within organized markets, this means ensuring that utilities can submit bids into the market on behalf of renewable generators that reflect the opportunity cost of curtailing these resources as well as ensuring that renewable plants are not excessively penalized for deviations from their schedules due to forecast errors. In environments in which vertically integrated utilities or another type of scheduling coordinator is responsible for determining system dispatch, the operator must begin to consider the role of renewable curtailment in scheduling and dispatch decisions for both renewable and conventional resources.

+ **Contracts between utilities and renewable facilities must be structured to allow for economic curtailment.** Historically, many power purchase agreements have been set up to pay renewables for the generation that they produce and have included provisions limiting curtailment under the premise that limiting risk and ensuring an adequate revenue stream to the project are necessary to secure reasonable financing. **Compensated curtailment,** under which developers are paid a PPA price both for generation that is delivered to the system as well for estimated generation that is curtailed, would be one means of achieving this goal.

To the extent that additional institutional barriers that would limit operators from effectively dispatching renewable resources exist, these barriers must also be addressed to allow for renewable integration at higher penetrations.

3. Another key step to enabling reliable and efficient operations under high penetrations is ensuring operators fully understand the conditions and circumstances under which renewable curtailment is necessary or desirable.

In some instances—namely, during oversupply conditions—the need to curtail is relatively intuitive; however, in other instances, the important role of curtailment may not be so obvious. For example, an operator faced with a choice between keeping a specific coal unit online and curtailing renewables or decommitting that coal unit to allow additional renewable generation should make that decision with knowledge of the confidence in the net load forecast as well as an understanding of the consequences of possible forecast errors. Similarly, an operator anticipating a large upward net load ramp may decide to curtail renewable generation prospectively to spread the ramp across a longer duration if the ramp rates of conventional dispatchable units are limited. Additional work is necessary to identify such operating practices and conditions in which renewable curtailment may be necessary outside of oversupply conditions to ensure reliable service.

The role of operating reserves at avoiding unserved energy under unexpected upward ramping events must also be considered. Resources under governor response or Automated Generation Control (AGC) respond quickly to small deviations in net load. Contingency reserves (spinning and supplemental or "non-spin" reserves) are used to manage large disturbances such as the sudden loss of a generator or transmission line. Additional categories of reserve products—for instance, "load following" or "flexibility" reserves—have been contemplated at higher renewable penetration, but have not yet been formalized. How these reserves are deployed will impact the magnitude of challenges encountered at higher renewable penetrations.

4. The consequences of extended periods of negative pricing must be examined and understood.

Historically, the centralized markets and bilateral exchanges of the Western Interconnection have, for the most part, followed the variable costs of producing power—most often the costs of fuel and O&M for coal and gas plants. In a future in which renewable curtailment becomes routine, forcing utilities to compete to deliver renewable generation to the loads to comply with RPS targets, the dynamics of wholesale markets will change dramatically. How the dynamics of negative pricing ultimately play out remains a major uncertainty; nonetheless, with frequent low or negative prices in a high renewables future, utilities, other market participants, and regulators will be confronted by a host of new questions:

+ How should generators that provide other services to the system during periods of low negative prices be compensated?
+ How can the proper signal for investment in generation resources be provided as frequent negative prices further erode margins in energy markets?
+ Do negative prices create new issues for loads, who, rather than paying for power from the wholesale market during periods of curtailment, would be paid to consume?
+ At what point does the prevalence of negative prices lead to new policy mechanisms other than production quotas to promote the development of new renewable energy?
+ How should future retail tariffs be designed to balance considerations of equity and cost causation with the radical changes in wholesale market signals?

These and other questions will require consideration as penetrations of renewables continue to increase.

5. While renewable curtailment is identified as the predominant challenge in operations at high renewable penetrations, its magnitude can be mitigated through efficient coordination of operations throughout the Western Interconnection.

The balkanization of operations today presents an institutional barrier to efficient renewable integration; by allowing full utilization of the natural diversity of loads and resources throughout the Western Interconnection, regional coordination offers a low-hanging fruit to mitigating integration challenges. A number of studies have identified the significant operational benefits that can be achieved through balancing authority consolidation, a conclusion that is supported by the reduction in renewable curtailment at high penetrations identified in this study.

6. Many supply- and demand-side solutions merit further investigation to understand their possible roles in a high renewable penetration electric system.

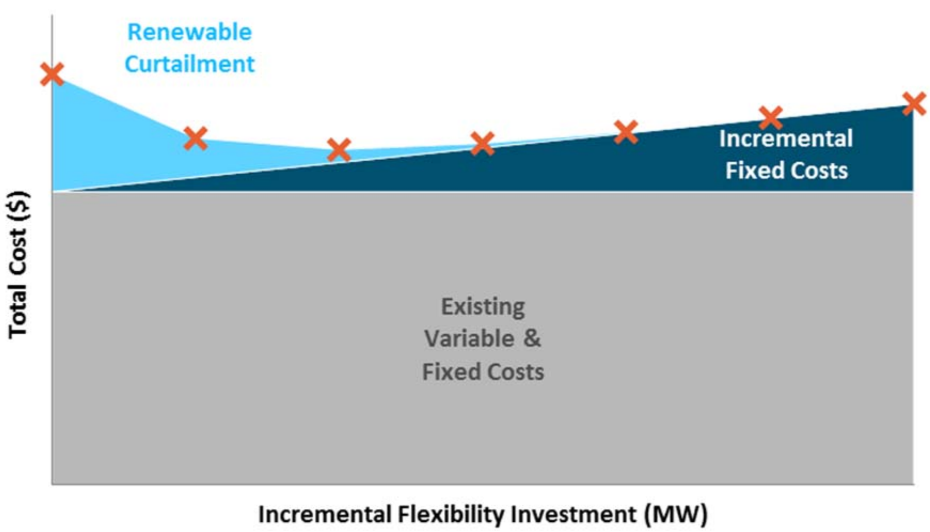
This study examines a select few of the multitude of possible supply- and demand-side portfolio measures available to utilities to illustrate how different attributes do (or do not) provide value to electric systems at high penetrations of renewable generation. The solutions examined within this study illustrate how different “types” of flexibility impact a system to differing degrees: whereas storage effectively mitigates renewable curtailment through its ability to charge during periods of surplus, fast-ramping flexible gas resources have a comparatively limited impact on operations, displacing less efficient gas generation resources but effecting minimal changes in curtailment.

7. The ability of renewable curtailment to serve as an “avoided cost” of flexibility points to an economic decision-making framework through which entities in the Western Interconnection can evaluate potential investments in flexibility and ultimately rationalize procurement decisions.

As the need for operational flexibility has grown, a number of efforts have explored whether additional planning standards—analogous to those used for resource adequacy today—are necessary to ensure that when the operating day comes, the generation fleet is sufficiently flexible to do serve load reliably. As this study demonstrates, so long as (1) the generation fleet is capable of meeting extreme peak demands, and (2) the operator can use curtailment as a relief valve for flexibility constraints, the operator can preferentially dispatch the system to avoid unserved energy. Thus, the consequence of a non-renewable fleet whose flexibility is inadequate to balance net load is renewable curtailment, whose implied cost is orders of magnitude smaller than the cost of unserved energy. In this respect, the determination of flexibility adequacy is entirely different from resource adequacy: for resource adequacy, conservative planning standards are justified on the basis of ensuring that costly outages are experienced exceedingly rarely; for flexibility adequacy, the appropriate amount of flexibility for a generation system is instead an economic balance between the costs of "inadequacy" (renewable curtailment) and the costs of procuring additional flexibility.

Because renewable curtailment can serve as an "avoided cost" of flexibility, the question of "flexibility adequacy" is economic, rather than technical. Renewable curtailment imposes a cost upon ratepayers, reflected in this study by the idea of the "replacement cost," and, to the extent it can be reduced through investments in flexibility, its reduction provides benefits to ratepayers. At the same time, designing and investing in an electric system that is capable of delivering all renewable generation to loads at high penetrations is, itself, cost-prohibitive. Between these two extremes is a point at which the costs of some new investments or programs that provide flexibility may be justified by the curtailment they avoid, but the cost of further investments would exceed the benefits. This idea is illustrated in Figure 12, which shows the tradeoff between the costs of renewable curtailment with the costs of a possible theoretical measure undertaken to avoid it. This study provides both an example of the type of analytical exercise that could be performed to quantify the operational benefits of flexibility solutions as well as a survey of the analytical considerations and tradeoffs that must be made in undertaking such an exercise.

Figure 12. Illustration of an economic framework for flexibility investment.



While not performed in the context of this study, this type of economic assessment of flexibility solutions to support renewables integration will depend on rigorous modeling of system operations combined with accurate representation of the costs and non-operational benefits of various solutions. The specific types of investments to enable renewable integration that are found necessary will vary from one jurisdiction to the next, but the overarching framework through which those necessary investments are identified may be consistent. Implementation of such an economic framework for decision-making for flexibility will foster the transition to high renewable penetration, enabling the achievement of policy goals and decarbonization while mitigating the ultimate impacts of those changes to the quality and cost of service received by ratepayers.