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# Flexibility Inventory for Western Resource Planners

**Andrew Mills and Joachim Seel**

**Energy Technologies Area**

**October 2015**

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## Disclaimer

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# Flexibility Inventory for Western Resource Planners

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Principal Authors

Andrew Mills and Joachim Seel

Ernest Orlando Lawrence Berkeley National Laboratory
1 Cyclotron Road, MS 90R4000
Berkeley CA 94720-8136

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## Acronyms and Abbreviations

| | |
|---|---|
| APS | Arizona Public Service |
| BPA | Bonneville Power Administration |
| CAISO | California Independent System Operator |
| CCGT | Combined-cycle gas turbine |
| CT | Combustion turbine |
| d | Day(s) |
| DR | Demand response |
| DSW | Desert Southwest |
| GW | Gigawatt(s) |
| h | Hour(s) |
| ICE | Internal combustion engine |
| IEA | International Energy Agency |
| IRP | Integrated resource plan |
| IRRE | Insufficient ramping resource expectation |
| LBNL | Lawrence Berkeley National Laboratory |
| min | Minute(s) |
| MW | Megawatt(s) |
| PGE | Portland General Electric |
| PNW | Pacific Northwest |
| PSCo | Public Service of Colorado |
| PSE | Puget Sound Energy |
| PUD | Public Utility District |
| RoR | Run of river |
| RPP | Resource Planning Portal |
| WECC | Western Electricity Coordinating Council |
| yr | Year(s) |

## Executive Summary

For utility planners, one criterion for choosing a portfolio of resources to meet future needs is that a portfolio has sufficient flexibility. Flexibility indicates the capability of the system to accommodate variability and uncertainty in demand, production from variable renewable resources like wind and solar, and other unforeseen events. Historically, flexibility has not been a primary concern and has not been systematically evaluated in utility planning studies. Growth in the share of energy produced by variable renewables will increase variability and uncertainty, potentially making flexibility more important in the future.

In order to better gauge the flexibility of planned resource portfolios, we developed a way to measure, at a screening-level, the overall flexibility of a portfolio. Our flexibility inventory is based on a methodology developed by the International Energy Agency (IEA) as part of a cross-country comparison of the potential to accommodate growing shares of variable renewables.[1] The key inputs to the flexibility inventory are the capacity of existing and planned resources, forecasts of peak demand, and several key parameters that are discussed in the full report.

The primary use of the flexibility inventory is to show trends in the balance between flexibility supply and flexibility demand over the planning horizon. Flexibility supply measures the capability of generation or demand to change in response to system conditions over various time scales relevant to power system operations (specifically we consider four time intervals of 15 min, 1 h, 6 h, and 36 h both in the up and down direction). Contributors to flexibility supply include conventional generation, demand response, bulk energy storage, and transmission interconnections. Flexibility demand is the amount that the net demand is expected to change over those different time scales, the degree to which those changes can be predicted ahead of time, and the contingency reserves.

The flexibility inventory can act as an "early warning" system. If planned resources lead to large changes in the balance of flexibility supply and flexibility demand, then additional detailed studies may be warranted to ensure the system will be sufficiently flexible in the future. Because it is a high-level analysis, and not a detailed study, it is just as important to understand what the flexibility inventory developed in this report does **not** do, as summarized in Table ES1.

[1] The original IEA methodology can be found in the IEA *Harnessing Variable Generation* report (2011).

**Table ES1. Summary of the Capabilities and Limitations of the Flexibility Inventory**

| What does the Flexibility Inventory do? | What does it <u>not</u> do? |
|---|---|
| Quantifies flexibility supply and demand based on planned generation | Does not identify which sources of flexibility should be added (no economic considerations) |
| Evaluates needs on various time intervals (15 min to 36 h) to find most constrained interval | Does not identify the cost of providing flexibility |
| Estimates contributions of different resources to flexibility supply based on simple parameters | Does not provide detailed determination of how much new flexibility should be added (if any), only tracks trends from year to year |
| Estimates flexibility demand based on summary statistics of load and variable generation | Does not conduct hourly or sub-hourly simulations of generation commitment and dispatch |

### Case Studies

To demonstrate the flexibility inventory, we apply the flexibility inventory to portfolios of resources identified in several utility integrated resource plans (IRPs) from various parts of the western U.S. The planned resources in these IRPs are tracked in the Resource Planning Portal (RPP, resourceplanning.lbl.gov), a database of loads and resources from IRPs managed by Lawrence Berkeley National Laboratory (LBNL). Specifically, we create an inventory for a utility in the Pacific Northwest (Puget Sound Energy [PSE]), a utility in the Desert Southwest (NV Energy), a regional collection of utilities in the Pacific Northwest (PNW), and a regional collection of utilities in the Desert Southwest (DSW). Utilities in the PNW have significant hydro and wind, while utilities in the Southwest rely mostly on conventional thermal plants and are expected to increasingly add solar.

For each of these regions we use the flexibility inventory to measure the balance between flexibility supply and flexibility demand over the planning horizon. To better understand the key parameters that impact the flexibility inventory, we analyze the sensitivity of the flexibility inventory to changes in parameters (e.g., thermal generator ramp rates and startup times) and changes in the capacity of key resources (e.g., capacity of combustion turbines or storage).

### Questions Informed by Results of the Flexibility Inventory

The results of the flexibility inventory can be used to answer a number of questions relevant to utility planners and regulators. However, it is important to note that answers to such questions will differ depending on the particular IRP or group of IRPs considered. The answers provided here reflect the results from the specific IRPs that we evaluated and are not meant to be generalizations.

*Are fast or slow sources of flexibility likely to be more important?*

Some resources, such as energy storage or demand response (DR) from direct load control, can provide fast response but potentially for a limited duration, whereas other resources, such as combined cycle natural gas turbines (CCGTs) can provide flexibility over longer periods. Which resource is more useful depends on which of the four flexibility intervals is the most constrained (i.e., has the lowest ratio of flexibility supply to flexibility demand).

Our results show that flexibility demand is greatest over the longer intervals (e.g., 6 h and 36 h), but the short flexibility intervals (15 min and 1 h) are the most constrained owing to the limited flexibility supply. In this case, fast sources of flexibility are more important than slower ones in determining the degree of surplus flexibility.

*Is more flexibility needed in one direction over the other?*

Some resources can only provide flexibility in one direction, or they provide it more easily or cheaply in one direction. For example, in our base case assumptions DR can provide flexibility in the up direction[2] (through load curtailment), but it does not provide flexibility down.[3] In contrast, wind or solar curtailment can more easily provide flexibility down than it can provide flexibility up.

Our results show that flexibility up is more important in the majority of cases owing to the contingency reserve requirements that increase flexibility demand in the up direction. Thus, sources of flexibility in the down direction, such as renewables curtailment, are less helpful for addressing flexibility in the binding flexibility interval than are sources of flexibility in the up direction. With higher shares of variable renewables, however, flexibility in the down direction may become the more important direction, in which case renewables curtailment or other sources of downward flexibility will be useful.

*With planned additions and retirements, is flexibility likely to become more or less important than it is today?*

Changes might occur over time in sources of flexibility supply (e.g., plant retirements or additions) and increases in flexibility demand with increasing shares of variable renewables. The trend in the balance between flexibility supply and flexibility demand with time can gauge the changing level of difficulty in managing the system.

Our results all show relatively gradual changes with time, with most showing a decreasing ratio of flexibility supply to demand and the 15 min up interval being the most constrained. The gradual decrease indicates that providing flexibility will be more important in the future. It does not, however, indicate a need for the dramatic changes that would be called for by a precipitous decline in the ratio of flexibility supply to demand.

[2] Flexibility up is the ability of the system to increase generation or decrease demand for electricity when needed.
[3] Flexibility down is the ability of the system to decrease generation or increase demand for electricity when needed.

*Are there opportunities to coordinate with neighbors to improve flexibility?*

If one utility has a low ratio of flexibility supply to demand, while a nearby utility has a high ratio, then coordination between the two utilities may alleviate the need to build new sources of flexibility. A difference in the ratio of flexibility supply to demand between IRPs indicates opportunities for such collaboration.

Our results show that the PNW group of utilities consistently has a higher ratio of flexibility supply to flexibility demand than the PSE utility. Thus, collaboration between PSE and utilities in the PNW might increase PSE's flexibility supply within the most constrained flexibility interval of 15 min in the up direction. In the DSW, the similar ratios of flexibility supply and flexibility demand for NV Energy and the DSW group of utilities suggests more limited opportunities for collaboration.

*What kind of resources can contribute to flexibility supply when it is most needed?*

For cases in which the ratio of flexibility supply to flexibility demand is decreasing, one option is to identify resources that can contribute to flexibility supply. Our capacity sensitivity analysis shows that resources providing flexibility in the up direction over a short time interval are the most helpful for increasing flexibility supply when it is needed most. In contrast, resources that are typically offline and cannot start quickly enough or resources that have too long of a notification period (e.g., DR with a day-ahead notification requirement) will not be as helpful. For cases where the flexibility is most constrained in the down direction (e.g., some portfolios with higher shares of variable renewables) resources that can provide flexibility down, such as energy storage, generation that is typically dispatched above its minimum generation level or can turn off quickly, or renewables curtailment, will be helpful.

*What types of questions is the Flexibility Inventory NOT equipped to answer?*

The flexibility inventory is not appropriate for answering some questions. For example, it cannot indicate which sources of flexibility are most cost effective, because it does not account for the economics of flexibility supply and demand. It is also unsuited to identifying the quantity of flexibility supply needed in a particular year, because it only provides a high-level assessment of trends over longer periods. Determining whether a particular resource is needed for flexibility would require a more detailed analysis. Finally, the resources that might offer flexibility may offer a number of other economically attractive services to the electricity system: even if a resource is not found effective at mitigating flexibility constraints, it may still be an economically attractive resource for other reasons.

## 1. Introduction

Growing shares of variable renewable energy are leading to concerns about the operational flexibility of the power system to manage increased uncertainty and variability. In this project, we apply a modified version of an existing, high-level methodology developed by the International Energy Agency (IEA)[4] to assess trends in flexibility supply and demand over the planning horizon in the western United States. The objective of the project is to provide metrics to utility planners and policymakers for assessing power system flexibility based on planned resources identified in utility integrated resource plans (IRPs).

Assessments of uncertainty and variability in power systems with increasing shares of renewables show increased flexibility needs (King et al. 2011, Huber et al. 2014). Integration studies—detailed grid simulations of power systems based on current practices or incremental changes to practices—are used to gauge the feasibility of operating power systems with large shares of wind and solar power (e.g., CAISO 2010a, Charles River Associates 2010, EnerNex 2010, EPRI 2011, GE Energy 2008, GE Energy 2010a, GE Energy 2010b, GE Energy 2014, Navigant et al. 2011, NYISO 2010, Piwko et al. 2007). These studies evaluate particular scenarios of wind and solar power expansion and identify particular conditions that might be most challenging. Owing to their technical complexity, these are often unique studies that are not routinely updated as resource plans or other factors change. In addition, they do not provide a metric to gauge the relative capability of the system to provide flexibility and the amount of flexibility needed.

Zhao et al. (2015) define a formal measure of flexibility based on a target range of uncertainty (i.e., demand for flexibility) and the capability of the system to respond to uncertainty (i.e., supply of flexibility). They use the metric to create a real-time situation-awareness tool for ISO New England that shows the degree to which flexibility capability exceeds the flexibility need in operational settings looking out over the next few hours. Where flexibility is limited, the operators can use the information to identify corrective actions while many options are still available. In operational settings, some of the steps operators can take to increase flexibility include increasing balancing reserves (e.g., BPA 2009, EnerNex 2010, GE Energy 2010a), adding flexible ramping constraints (Bouffard and Ortega-Vazquez 2011, Gu and Xie 2013, Wang and Hobbs 2014), or directly accounting for uncertainty in unit commitment through methods like robust unit commitment (e.g., Bertsimas et al. 2013) or stochastic unit commitment (Cheung et al. 2015, Papavasiliou and Oren 2013, Ruiz et al. 2009).

Such a situation-awareness tool could be helpful from a planning perspective as well. In the context of planning, the questions shift to determining whether resources available in future years will provide the flexibility needed to accommodate changing loads and growing shares of variable renewable energy resources. Flexibility has not historically been systematically considered in the planning context, because commonly used, commercial capacity-expansion models do not explicitly or fully account for many factors that constrain flexibility (e.g., ramp rates, startup times) or drive the need for more flexibility (e.g., uncertainty). Similarly, most reliability planning metrics, such as Loss of Load Expectation (LOLE), do not account for

[4] The original IEA methodology can be found in the IEA *Harnessing Variable Generation* report (2011).

flexibility. As a result, most planning studies like IRPs do not address flexibility in a comprehensive manner (Wilkerson et al. 2014). This obscures whether resource plans lead to increased or decreased flexibility supply relative to demand.

Because changes to the mix of resources may be justified for cases in which flexibility appears to be a constraining factor, efforts are underway to improve representation of flexibility in planning in at least-California (CPUC 2014), Oregon, and Colorado (Exeter Associates 2015), Washington (PSE 2013), and the Tennessee Valley Authority (TVA 2015). The Oregon Public Utility Commission, for example, now requires flexibility assessments in IRPs for investor-owned utilities (e.g., PacifiCorp 2015). Moreover, because common planning tools do not account for flexibility, revised capacity-expansion models have been proposed and are under development. Ma et al. (2013) propose a new flexibility metric and a capacity-expansion model that accounts for flexibility needs. They show that flexible generation can earn a premium relative to inflexible generation with increasing shares of wind. Hargreaves et al. (2014) introduce economic penalty terms for flexibility violations[5] in a modified form of a production-cost model (REFLEX) to examine the economic attractiveness of different options for increasing system flexibility. With this tool, flexibility is incorporated into traditional measures of production cost to help select future resources.

Several options for measuring flexibility over the planning horizon are available. The flexibility metric developed by Zhao et al. (2015), for example, can also be applied in the context of resource planning, though they only demonstrate the metric in an operational setting. Meanwhile, Lannoye et al. (2012a, 2012b) introduced a probabilistic flexibility metric called the insufficient ramping resource expectation (IRRE). It measures the expected number of events during which a power system cannot manage predicted or unpredicted ramps in the net demand.

On the other end of the complexity spectrum, various approaches can assess flexibility of power systems in the planning context at a screening level. In these approaches, flexibility is estimated at a high level to determine if further analysis is warranted or to compare flexibility across different regions. As part of the transmission-planning process at the Western Electricity Coordinating Council (WECC), for example, flexibility was measured as the ratio of natural gas-fired combustion turbine (CT) capacity and 15% of hydropower capacity to the nameplate capacity of wind (WECC 2013). That measure shows trends in flexibility between the power system today compared with future years and scenarios.[6] A decline in the flexibility metric suggests that flexibility will be more important in the future than it is today, particularly in scenarios with higher shares of renewable energy. A somewhat-more sophisticated screening-level flexibility metric is reported as part of a cross-country comparison in the IEA *Harnessing Variable Generation* report (2011).

[5] A flexibility violation occurs when the power system is not able to maintain balance between supply and demand while maintaining adequate operating reserves. Examples of flexibility violations include unserved energy, overgeneration, and operating reserves that fall below desired levels.
[6] WECC measured the flexibility for the 2012 system, the 2022 Common Case, and eight different 2032 futures. In all cases the flexibility was lower in future years than in 2012.

The present work develops and applies a screening-level flexibility inventory approach that is intended to be easily applicable to different resource plans, like the WECC approach, while also building on insight from more detailed flexibility evaluations to develop measures of flexibility need and supply that are more refined than the WECC metric. Specifically, we focus on characterizing flexibility using a modified version of the IEA methodology (IEA 2011) for several reasons. Foremost is that the IEA methodology is appropriate for a high-level screening analysis in which broad trends with time and across regions are more important than the specific quantitative value of the metric at any particular time.[7] Also important, the IEA methodology can be applied to the Resource Planning Portal (RPP, resourceplanning.lbl.gov), a database of loads and resources from IRPs managed by Lawrence Berkeley National Laboratory (LBNL), in an automated fashion. This means that, once the methodology is integrated with the IRP database, the flexibility inventory implied by resources in the IRP database can be tracked in an ongoing fashion, as opposed to being a unique study. Because it is a high-level analysis, and not a detailed study, it is just as important to understand what the flexibility inventory developed in this report does **not** do, as summarized in Table 1.

**Table 1. Summary of the Capabilities and Limitations of the Flexibility Inventory**

| What does the Flexibility Inventory do? | What does it not do? |
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| Estimates flexibility demand based on summary statistics of load and variable generation | Does not conduct hourly or sub-hourly simulations of generation commitment and dispatch |

Given the advantages and limitations of our approach, we expect that the flexibility inventory developed here can be used as an "early warning" system. If planned resources lead to large changes in the balance of flexibility supply and flexibility demand, then additional detailed studies may be warranted to ensure the system will be sufficiently flexible in the future. Utility planners, utility regulators, regional transmission planners, and developers of flexible resources may all gain insight from application of the flexibility inventory to IRPs.

The remainder of this report describes essential features of the IEA flexibility methodology, and modifications to the method, starting in Section 2. Section 3 describes the data and assumptions used to apply the modified methodology to the Western Interconnection. Section 4 presents

[7] In addition to a quantitative evaluation of flexibility, the IEA methodology includes an approach to qualitatively assess the flexibility of various resources in a region. We rely only on the quantitative component of the IEA methodology and do not employ the qualitative component.

results of example applications of the inventory to specific IRPs in the database and collections of IRPs within a regional footprint. It also includes sensitivity analyses of the resulting flexibility inventories to determine which assumptions and parameters are most important and to obtain insight into ways to increase flexibility supply (or decrease flexibility demand) in future years. Section 5 uses the results of the flexibility inventory to answer questions about flexibility that are relevant to planners. We discuss the overall usefulness of a high-level flexibility screening tool, offer conclusions, and suggest directions for future work in Sections 6.

## 2. Methodology

The concept of a flexibility inventory is based on comparing the ability of resources in a power system to supply flexibility against the need for flexibility imposed by uncontrolled variability and uncertainty. For the remainder of this report, we define "**flexibility supply**" as the capability of generation or demand to change in response to system conditions over various time scales relevant to power system operations (day ahead, multiple hours ahead, 1 h ahead, and in real time), accounting for system or institutional factors that limit access to the technical capability.[8] We define "**flexibility demand**" as the amount that the net demand will change over those different time scales, the degree to which those changes can be predicted ahead of time, and the contingency reserves.[9] The remainder of this section explains how we create a flexibility inventory, estimate the demand for flexibility, estimate the supply of flexibility, and apply these estimates to case studies of resources identified in IRPs in the western U.S.

### 2.1 Flexibility Inventory

A flexibility inventory is the estimate of flexibility supply and flexibility demand over the planning horizon based on planned generation resources and load forecasts. In this case, we use the resources (and loads) identified in a utility's preferred portfolio (as reported in an IRP) to represent the planned resources (and loads) in future years. The planned resources include generation capacity that is not otherwise retired in the preferred portfolio and contracts with other generating resources.

Following the IEA methodology, the flexibility inventory tracks flexibility supply and demand across four particular time intervals[10] that are relevant to power system operations in both the up and down direction. The four time intervals, called the flexibility intervals, are 15 min, 1 h, 6 h, and 36 h. The up direction (**"flexibility up"**) represents the ability of the system to increase generation or decrease demand for electricity when needed. The down direction ("**flexibility down**") represents the ability of the system to decrease generation or increase demand for electricity when needed.

For any particular future year, the "**binding interval**" is the flexibility interval and direction for which the ratio of the flexibility supply to flexibility demand is the lowest. The ratio of flexibility supply to flexibility demand in the binding interval is the "**binding flexibility ratio**," which is the primary metric used to represent the flexibility inventory across time and regions.[11] A flexibility inventory with a binding flexibility ratio that is well above one will have more

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[8] Our use of *flexibility supply* is analogous to the "largest variation range of uncertainty within which the system can remain feasible under a given response time horizon," used to describe flexibility in Zhao et al. (2015).
[9] Our use of *flexibility demand* is analogous to the "variation range of uncertainty that the system aims to accommodate," used to describe the target uncertainty range in Zhao et al. (2015).
[10] The time intervals are used to characterize the amount that the net demand might change and the options available to the system operator to respond to those changes.
[11] In contrast, Zhao et al. (2015) define a flexibility metric for any flexibility interval as the net difference between flexibility supply and flexibility demand (rather than the ratio), without limiting the focus to a particular binding interval.

flexibility supply than flexibility demand in the most critical flexibility interval. Conversely, a region with a binding flexibility ratio that is less than one faces higher risk that the demand for flexibility will outstrip the supply of flexibility over one or more flexibility intervals.

### 2.2 Flexibility Demand

Demand for flexibility is driven by the variability and uncertainty of the net demand (load less variable renewable generation) and the need for contingency reserves.[12,13] Variability is defined here as the change in net demand over hours and days, while uncertainty is defined as the inability to predict the exact magnitude of those changes in net demand. Variability and uncertainty contribute to flexibility demand in both the up and down directions,[14] whereas contingency reserves only contribute to flexibility demand in the up direction (i.e., to cover the loss of a large generator). The contingency reserve contribution to flexibility demand applies across all four flexibility intervals. Because the contingency reserve requirement is directly added to the variability and uncertainty of the net demand, our methodology assumes that contingency reserves are not available to meet extreme forecast errors or ramps in the net demand.

Following the IEA methodology, flexibility demand is based on summing the estimated variability and uncertainty of net demand for all flexibility intervals of 6 h and shorter. In effect, this assumes that the worst ramp and the worst forecast error can occur simultaneously, and resources used to meet a ramp cannot be used to meet a forecast error. For the longer flexibility interval of 36 h, only variability is assumed to contribute to flexibility demand.[15]

In the flexibility inventory, the variability and uncertainty of the net demand are estimated based on the variance and correlation of ramps in demand, wind, and solar over the different flexibility intervals. The IEA methodology on the other hand assumes that the worst load ramps can occur at the same time as the worst wind ramps and worst solar ramps (implying perfect correlation between ramps across demand, wind, and solar). By introducing the correlation of ramps into the estimate of the worst net-demand ramps, the approach applied in the flexibility inventory allows for extreme ramps to be lower than in the IEA methodology, as long as the ramps are less than

[12] We do not directly account for forced outages of individual resources but use instead the contingency reserve requirement (e.g., 6% of peak demand) to account for outages in conventional generators (further elaborated in Section 3.1).

[13] System operators also sometimes dispatch resources in order to manage imbalances caused by interchange schedules on transmission lines that are flat over the hour (elsewhere in the literature these are referred to as scheduling leaps, e.g., Hirth and Ziegenhagen 2015). Managing these interchange schedules can also contribute to flexibility demand. We did not include it in this analysis since interchange schedules are not part of the IEA methodology and data required to estimate the magnitude of the effect for various regions is limited.

[14] In this analysis, we do not consider curtailment of wind and solar to provide flexibility in the down direction. As shown in Section 4.2, the binding flexibility interval across regions and future years proved to be in the up direction and could thus not have been addressed with renewables curtailment. Adding renewables curtailment as a form of flexibility down would be possible in future applications of the flexibility inventory.

[15] The IEA methodology uses the greater of the variability or the uncertainty for the 36 h flexibility interval. For the parameters used in this analysis, as described later, the variability in net demand over 36 h was always greater than the uncertainty over 36 h.

perfectly correlated.[16] We assume that the "worst" ramp or forecast error is based on three times the standard deviation of the net-demand ramps and forecast errors. The choice of three standard deviations reflects our approximation of the risk tolerance of decision makers. A decision maker who is willing to tolerate greater risk would choose fewer standard deviations, resulting in a lower flexibility demand.[17,18] For estimating the flexibility demand, the "worst ramp" was determined by measuring the largest net-demand delta over the four flexibility intervals (15 min, 1 h, 6 h, and 36 h), independent of the time of day when the ramps occur. Additional details regarding this approach are in Section 3 and Appendix A.

## 2.3 Flexibility Supply

Broadly, we consider flexibility supply to be based on the capabilities of the system to change in response to a need. The flexibility supply is more of a reliability-focused metric than an economic metric, because we do not attempt to assess the economics of providing the flexibility. Following the IEA methodology, the flexibility inventory uses four main types of resources to characterize flexibility supply: conventional generation (thermal and hydro plants), energy storage, demand response (DR), and transmission interconnections with neighboring regions. The total flexibility supply is based on the sum of the flexibility supply from each of the individual resources.

### 2.3.1 Conventional Generation

Flexibility supply from conventional generation depends on the capabilities of the generation to change output and the initial state of the generator when needed to provide flexibility. We refer to the initial state of the generator when needed to provide flexibility as the **"typical dispatch"** of the generator. As in the IEA methodology, the capabilities depend on the maximum ramp rate, the minimum generation level, and the startup and shutdown times of the generation.[19] Typical dispatch, on the other hand, depends on the manner in which generation is dispatched to maintain a balance between supply and demand. For the most part, typical dispatch depends on the merit order of the generator and demand. Generation with low variable operating cost is usually dispatched to its full output before more expensive generation is dispatched.

[16] In theory, this approach could also be applied to summing net-demand variability and uncertainty. However, we could not implement it in this study owing to limitations in the available data; in particular, we lack estimates of the correlation between net-demand variability and net-demand uncertainty over the different flexibility intervals.

[17] Zhao et al. (2015) describe this choice as follows: "The target range [flexibility demand] reflects the decision makers' risk preference, and is subjectively set by operation or planning criteria. The larger the target range [i.e., the greater the number of standard deviations] the more conservatively the decision makers design or operate the system."

[18] Puget Sound Energy uses the 95$^{th}$ percentile of net load volatility to establish their estimate of flexibility demand. If deviations were normally distributed then the 95$^{th}$ percentile would approximately correspond to two standard deviations. Our estimate of flexibility demand is therefore more conservative than used by PSE and will tend to overstate flexibility demand. We examine the impact of different choices of the standard deviations in a parameter sensitivity in Section 4.

[19] This analysis uses startup and shutdown times instead of minimum up or down times to approximate flexibility supply limitations of conventional generators and associated potential over-generation periods. Sensitivity analysis regarding the choice of those parameters is discussed in Section 4.4.1.

The effects of typical dispatch and the capabilities of a thermal generator on the flexibility supply over different flexibility intervals are illustrated in Figure 1. In this case the typical dispatch of the generator (Pdispatch) is such that it is online and generating between the minimum generation level (Pmin) and its maximum capacity (Pmax). Over short flexibility intervals (e.g., 15 min), the flexibility supply is limited by the ramp rate of the generator. Over longer intervals, the flexibility in the up direction is limited by the difference between the typical dispatch level and the maximum capacity of the generator. Flexibility in the down direction is limited by the difference between the typical dispatch level and the minimum generation level, until the unit can fully shut down; this illustrative generator can shut down after 6 h.

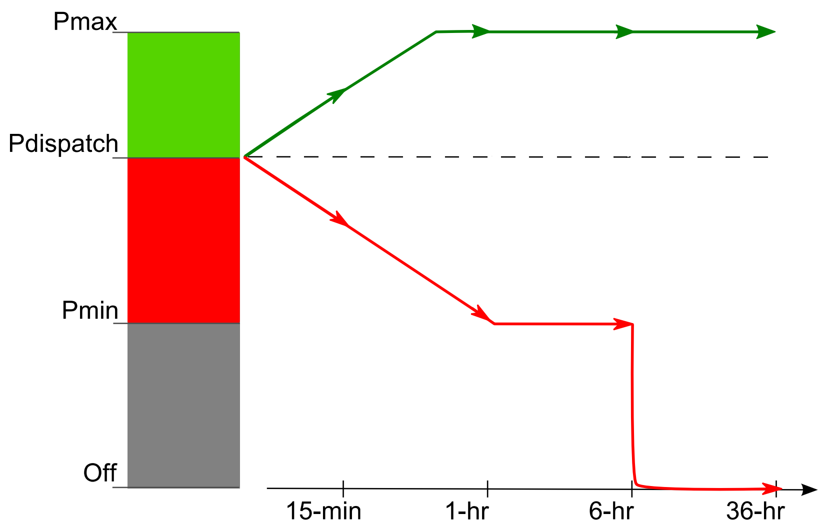


**Figure 1. Flexibility Supply from a Conventional Generator**

Following the IEA methodology, the total flexibility supply from conventional resources is based on an estimate of the fraction of generation that is in one of four possible states when flexibility supply is needed. The four states are offline, near minimum generation, near the middle of the operating range, and near maximum. The fraction of generation in each of these four states is based on typical dispatch during peak-load or low-load hours.[20]

The IEA method associates typical dispatch with peak- or low-load hours differently depending on the flexibility interval and direction. For flexibility intervals of 15 min and 1 h, the IEA

[20] Following the IEA methodology, traditional electricity demand (not net demand) was analyzed to determine the typical dispatch level of conventional generators. This raises the question: Why not use typical dispatch based on net demand instead? There are two reasons. First, we can look at historical dispatch during high-load and low-load periods, but we cannot do the same for the net demand for futures with high renewables. Second, the effects of wind and solar generation are incorporated in our estimates of the flexibility demand, rather than through assessments of the typical dispatch parameters. Including wind and solar generation in our assessment of typical dispatch levels of conventional generators would yield misleading results, because the impact of wind and solar generation would be counted twice.

method uses typical dispatch during peak-load times for flexibility in the up direction and during low-load times for flexibility in the down direction. Over the longer intervals of 6 h and 36 h, the combinations of flexibility direction and typical dispatch are switched: the method uses typical dispatch during low-load times for flexibility in the up direction and during peak-load times for flexibility in the down direction (Table 2).

The logic of this approach in the IEA method is as follows. During low-load conditions (illustrated on the left side of Figure 2) ramping generators down to manage 15 min and 1 h variations is expected to be challenging. Generation is not expected to ramp down further over the longer periods of 6–36 h, because load is already near its minimum. Instead, generation will need to increase over these longer intervals, meaning flexibility supply in the up direction will be most challenging. During peak-load conditions (illustrated on the right side of Figure 2) 15 min and 1 h variations around peak load will be challenging to meet in the up direction. In contrast, because the load is already at its peak, ramping generation down over the next 6–36 h is expected to be challenging.

Similar logic is applied in the flexibility inventory. Hence, we largely follow the original IEA assumptions as summarized in Table 2. One exception to this is introduced here and described in more detail in Section 3. In the Pacific Northwest (PNW), which has a large hydro resource and relatively little reservoir storage capacity, we assume that the constrained low period is during high-hydro/low-load periods (not just low-load periods) and that the constrained high period is during low-hydro/peak-load periods (not just peak-load periods).

**Table 2. System Conditions Used To Determine Typical Dispatch of Conventional Generators**

| Flexibility Interval | Up Direction | Down Direction |
|---|---|---|
| **15 min** | Peak Load | Low Load |
| **1 h** | Peak Load | Low Load |
| **6 h** | Low Load | Peak Load |
| **36 h** | Low Load | Peak Load |

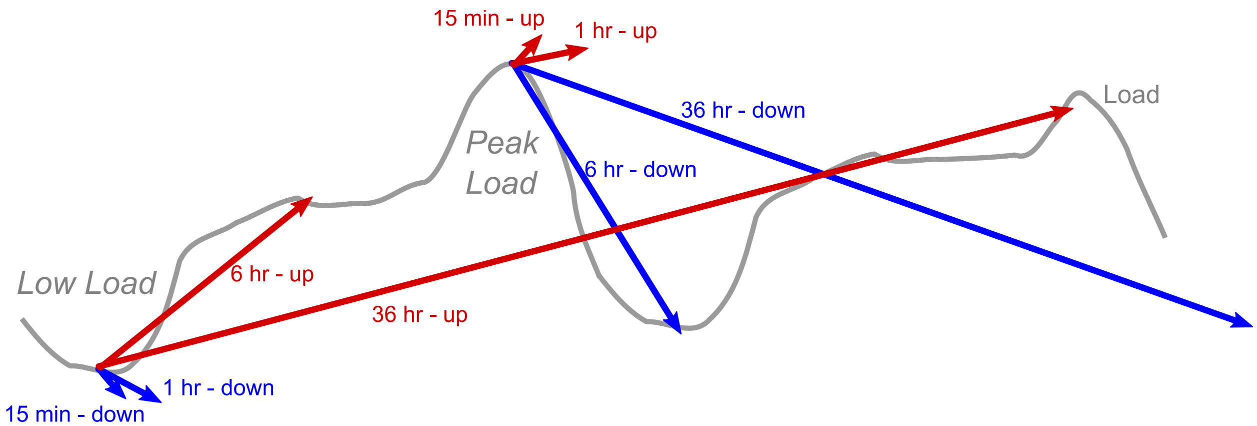


**Figure 2. Illustration of System Conditions Used To Determine Typical Dispatch of Conventional Generators**

Additional details regarding the parameters used to define typical dispatch and the capabilities of different conventional generation are provided in Section 3. The system conditions of low and peak loads are only used for determining the typical dispatch parameters required to estimate the flexibility-supply capabilities of conventional generators. These system conditions are not used for quantifying the potential capabilities of energy storage, DR, and transmission.

#### 2.3.2 Energy Storage

Following the IEA methodology, flexibility from energy storage is based on the full nameplate capacity of energy storage (i.e., the megawatt rating) for both the up and down directions, limited only by its ramp rate. The contribution of energy storage over longer flexibility intervals is not limited by the size of the storage reservoir (i.e., the megawatt-hour rating), though IEA notes that the ability of energy storage to sustain output over longer flexibility intervals is limited. By ignoring the size of the storage reservoir in the calculation of flexibility supply we are in effect assuming a large reservoir (> 36 h at full capacity) or that the energy storage resource will have an opportunity to cycle multiple times within longer flexibility intervals.[21]

#### 2.3.3 Demand Response

The capability of DR to provide flexibility depends on three characteristics: capacity, notification period, and directionality. The IEA methodology assumes DR is fully controllable such that DR can provide flexibility in both the up (curtail load) and down (increase load) directions over all four flexibility intervals. In contrast, many DR programs implemented by utilities in the western U.S. can only provide flexibility in the up direction (i.e., load curtailment) and only for flexibility intervals longer than the notification period (e.g., flexibility intervals greater than 24 h for DR with a day-ahead notification). We reflect these constraints by limiting the flexibility supply to the up direction and classifying demand response programs by their notification period. As described further in Section 3, we identify three types of DR programs: direct load control (no notification required), interruptible (30-min notification), and other (24-h notification). Similar to the IEA methodology, we do not limit the capability of DR to provide flexibility based on the duration of events, we only limit capabilities based on the notification requirement.

#### 2.3.4 Transmission Interconnection

In the IEA methodology, transmission into and out of a region is a source of flexibility in the up and down directions, respectively, and the contribution of transmission is limited only by the interconnection capacity. In our methodology, we similarly assume that transmission is a source of flexibility up and down, but, as detailed in Section 3, we limit the contribution of transmission based on the maximum historically observed ramp rates over the different flexibility intervals.

[21] As described later, the binding flexibility interval is found to be relatively short, either 15 min or 1 h, implying that the capability of energy storage to provide flexibility on the 6 h to 36 h interval is relatively less important. In cases where the longer flexibility intervals are binding, the assumptions about the capability of energy storage to provide flexibility over longer intervals should be revisited.

### 2.4 Summary of Differences between IEA and Our Flexibility Inventory

To conclude our description of flexibility demand and supply assumptions, Table 3 summarizes the similarities and differences between the IEA methodology and our approach.

**Table 3. Comparison of Flexibility Demand and Supply Assumptions Used by IEA and Our Flexibility Inventory**

| Flexibility Demand or Supply | IEA | Flexibility Inventory |
|---|---|---|
| **Flexibility Demand** | Sum of variability and uncertainty of load, wind, and solar (assuming perfect correlation among resources) plus contingency reserves | Similar to IEA, but accounting for correlation in ramps or forecast errors for load, wind, and solar (i.e., does not assume perfect correlation between load, wind, and solar) |
| **Conventional Generation (Thermal and Hydro)** | Limited by physical constraints and typical dispatch | Generally same as IEA, but with adjustment reflecting historical operations and parameters specific to WECC |
| **Demand Response** | Limited only by nameplate in either direction over all intervals | Three types of DR:<br>• Direct load control (no notification to curtail)<br>• Interruptible (30-min notification to curtail)<br>• Other (24-h notification to curtail) |
| **Bulk Energy Storage** | Limited by nameplate and ramp rate | Same as IEA method |
| **Transmission Interconnection** | Limited only by transmission capacity over all intervals | Limited by capacity and historically observed ramp rates |

### 2.5 Case Study

We apply the flexibility inventory to resources identified in IRPs from various parts of the western U.S. Specifically, we create an inventory for a utility in the PNW (Puget Sound Energy [PSE]),[22] a utility in the DSW (NV Energy),[23] a collection of utilities in the PNW,[24] and a

[22] Using the PSE 2011 IRP and a supplemental survey administered by LBNL.
[23] Using the NV Energy 2012 IRP and a supplemental survey.
[24] The IRPs included in the region are from PSE, Portland General Electric (PGE), Avista, Idaho Power, Chelan Public Utility District (PUD), Clark Public Utilities, Cowlitz PUD, Grant PUD, Northwest, Seattle City Light, Snohomish PUD, and Eugene Water and Electric Board.

collection of utilities in the DSW.[25] Utilities in the PNW have significant hydro and wind, while utilities in the Southwest rely mostly on conventional thermal plants and are expected to increasingly add solar (Table 4).

**Table 4. Peak Demand, Wind Capacity, and Solar Capacity for each Inventory**

| | | | Demand/Capacity | |
|---|---|---|---|---|
| **Utility/Region** | **Load/Resource** | **2012 (GW)** | **2020 (GW)** | **2027 (GW)** |
| **PSE** | Peak Demand | 5.0 | 5.1 | 5.5 |
| | Wind | 0.82 | 1.12 | 1.22 |
| | Solar | 0.00 | 0.00 | 0.00 |
| **PNW** | Peak Demand | 18.7 | 21.8 | 22.9 |
| | Wind | 1.74 | 2.09 | 2.05 |
| | Solar | 0.00 | 0.01 | 0.06 |
| **NV Energy** | Peak Demand | 5.5 | 5.7 | 6.3 |
| | Wind | 0.15 | 0.16 | 0.20 |
| | Solar | 0.18 | 0.34 | 0.27 |
| **DSW** | Peak Demand | 18.7 | 20.5 | 23.8 |
| | Wind | 0.50 | 0.71 | 1.11 |
| | Solar | 0.46 | 1.31 | 1.44 |

The data and assumptions used in this case study are based on commonly used datasets or historical observations that focus on the western U.S. The intention of the case study is to demonstrate the capabilities of the flexibility inventory, create an initial set of assumptions and parameters, and highlight parameters to which the flexibility inventory is most sensitive. The variable renewable capacity in these particular IRPs is proportionally much lower than in some states with high renewables targets and limited supply of non-variable renewables (e.g., California). Though we do not present the results in detail here, we did examine cases where we greatly increased wind or solar penetration beyond the level identified in the IRP (without changing anything else in the portfolio) in order to understand the degree to which results may change in situations with higher shares of variable renewables. We describe these supplementary results where appropriate in the Results, Discussion, and Conclusions.

[25] The utility IRPs included in the region are from Arizona Public Service (APS), El Paso Electric, NV Energy, Tucson Electric Power, and Public Service New Mexico.

## 3. Data and Assumptions

Two main approaches are used to create the flexibility inventories in the case study: 1) identify load forecasts and planned resources from IRPs in the LBNL IRP database, and 2) develop parameters that are not included in the IRP database to characterize flexibility supply and flexibility demand. This section is separated into descriptions of the data available in the IRP database and the process for developing the additional parameters.

### 3.1 Resource and Load Forecasts in the IRP Database

For the purpose of the flexibility inventory, the IRP database provides two key datasets: the utility forecast of peak demand over its planning horizon and the capacity of all existing and planned resources the utility will use to meet its needs (including utility-owned and contracted resources). We map these different resources to either flexibility supply or flexibility demand. In general, the IRP database only provides information on the capacity and timing of each of these resources. As described in the next section, we use external analysis to estimate the flexibility of each of these resources.

Resources in the IRP database that contribute to flexibility **demand** include the load (net of planned energy efficiency) as well as wind and solar resources. In addition, we assume contingency reserves equivalent to 6% of the peak demand must be met in all flexibility intervals.

Resources in the IRP database that contribute to flexibility **supply** are conventional generation, energy storage, DR, and transmission. We categorize individual conventional generation resources in the IRP database as one of the following types:

- Coal
- Cogeneration
- Combined-cycle gas turbine (CCGT)
- Combustion turbine (CT)
- Geothermal
- Hydro
- Hydro - run of river (RoR)
- Internal combustion engine (ICE)
- Nuclear
- Steam (natural gas or biomass)

All energy storage resources in the IRP database are treated as one energy storage type. Similarly, all transmission is treated as one transmission type.[26] We segment DR into three types:

- Direct load control (can immediately curtail load)
- Interruptible load (can curtail load with 30-min notice)

[26] Further segmentation was not warranted given the limited information beyond the nameplate generation capacity of energy storage and transmission in the IRP database and the relatively simple approach used to calculate flexibility supply from these resources.

- Other DR (can curtail load with 24-h advance notice)

## 3.2 Parameters

Because the IRP database only includes the capacity and timing of each of these resources, we rely on additional analysis, data, and assumptions to develop several parameters that define the flexibility of the resources. We first describe the parameters related to flexibility demand and then describe the parameters related to flexibility supply.

### 3.2.1 Flexibility Demand Parameters

From the IRP database, we have forecasted peak load, planned wind capacity, and planned solar (photovoltaic) capacity into future years (Table 4). We translate that information into flexibility demand over different time intervals based on parameters estimated from several highly detailed generation and uncertainty datasets, augmented by parameters in the literature.

To estimate parameters related to variability of load, wind, and solar, we used four primary datasets: 1-min data for the California Independent System Operator (CAISO 2011), 1-min data for APS (Mills et al. 2013), 10-min data for PGE, and 10-min data for Public Service of Colorado (PSCo). The first two datasets were developed for previous studies. We developed the last two datasets using data in the Western Wind and Solar Integration Study datasets (Lew et al. 2013), information regarding the location of existing and planned resources, and interpolations of historical hourly load data for the years 2004–2006 from the Ventyx Velocity Suite.

We defined the contribution of load, wind, and solar to flexibility demand to be the 99.7$^{th}$ percentile of the changes in net demand (load less wind and solar power) and then directly observed the contribution to flexibility demand with each of these datasets. We then used these direct observations to validate a “3-sigma” approximation method. In the approximation, we use the standard deviation of the load variability, the wind variability, and the solar variability over the different flexibility intervals along with the correlation among the different sources to estimate the standard deviation of the net demand. We then multiply the estimated standard deviation of the net demand by a factor of three to estimate the maximum changes that the system is designed to accommodate. Additional details can be found in Appendix A.

We estimated the standard deviation of the load, wind, and solar and the correlation between terms for each of the four primary datasets. We then averaged the parameters across all datasets to form our best estimate.[27] This average value was then used to calculate the 3-sigma variability for each of the four cases. The 3-sigma estimate was found to provide a reasonable approximation of the direct measurement of the 99.7$^{th}$ percentile for each of the four datasets. As an example, Figure 3 shows the 99.7$^{th}$ percentile of the variability in the net demand that was directly measured from the APS dataset along with the estimate of the variability based on the average standard deviation and correlation parameters.

[27] Alternatively, we could have used region-specific estimates of the variability and correlation parameters. We found that the average parameters across all four datasets performed no worse than the parameters developed from each dataset independently, indicating little additional value from using region-specific estimates.

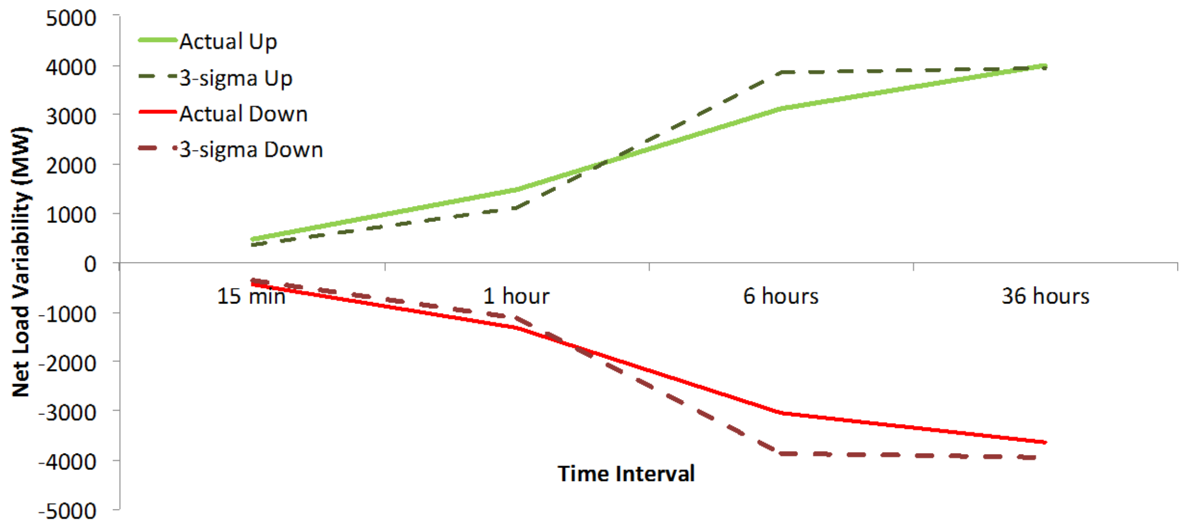


**Figure 3. Validation of 3-Sigma Approximation Compared to the Actual, Directly Measured 99.7th Percentile Variability of Net Demand Using the APS Dataset**

To characterize the uncertainty of net demand, we similarly use the 3-sigma approach described for variability. We have limited datasets that include the uncertainty of load, wind, and solar over the flexibility intervals, so instead we rely much more on values reported in the literature (CAISO 2010a, CAISO 2010b, Charles River Associates 2010, GE Energy 2010a, Hodge et al. 2012, Lew et al. 2013, Makarov et al. 2009, Mills et al. 2013). In particular, we extracted from each of these studies the standard deviation of the forecast error for load, wind, and solar over forecast horizons similar to the flexibility intervals used in our methodology. For each flexibility interval and each resource, we then averaged the standard deviations of the forecast errors. We assume that the correlation of forecast errors among load, wind, and solar is close to zero across all flexibility intervals.

The only other source of flexibility demand is contingency reserves. We assume that contingency reserves are equivalent to 6% of the forecasted peak demand in each year. Contingency reserves increase flexibility demand across all flexibility intervals, but only in the up direction.

The impacts of the parameters used to define the flexibility demand are shown in Figure 4, for a hypothetical system with a peak load of 1,000 MW. To illustrate the impact of adding wind and solar, we first add solar sufficient to meet 5% of the annual energy demand, then add wind sufficient to meet 10% of the annual energy demand, and finally add both wind and solar.[28] In the shorter flexibility intervals (15 min and 1 h), increasing the share of variable renewables increases the flexibility demand. Increasing the share of wind also increases the flexibility demand in the longer flexibility intervals (6 h and 36 h) because variability and uncertainty in wind somewhat exacerbates variability and uncertainty in demand. One interesting result is that the addition of 5% solar tends to decrease the overall flexibility demand in the longer flexibility

[28] Wind and solar are assumed to produce different amounts of energy per unit of installed capacity. In this illustration we assume similar installed capacities of wind and solar which leads to different energy penetrations.

intervals (6 h and 36 h) relative to the flexibility demand from load alone (with or without the addition of 10% wind). On the other hand, the correlation between load and solar ramps is such that the addition of solar leads to smaller ramps in the net demand, resulting in lower flexibility demand. Similarly the flexibility demand is smaller with 5% solar and 10% wind than for the load alone. This is not a general finding but depends on the particular penetration of solar. For example, when the penetration of solar is increased to above about 7% of the annual energy demand, the flexibility demand in the 6 h flexibility interval begins to exceed the flexibility demand of load alone.

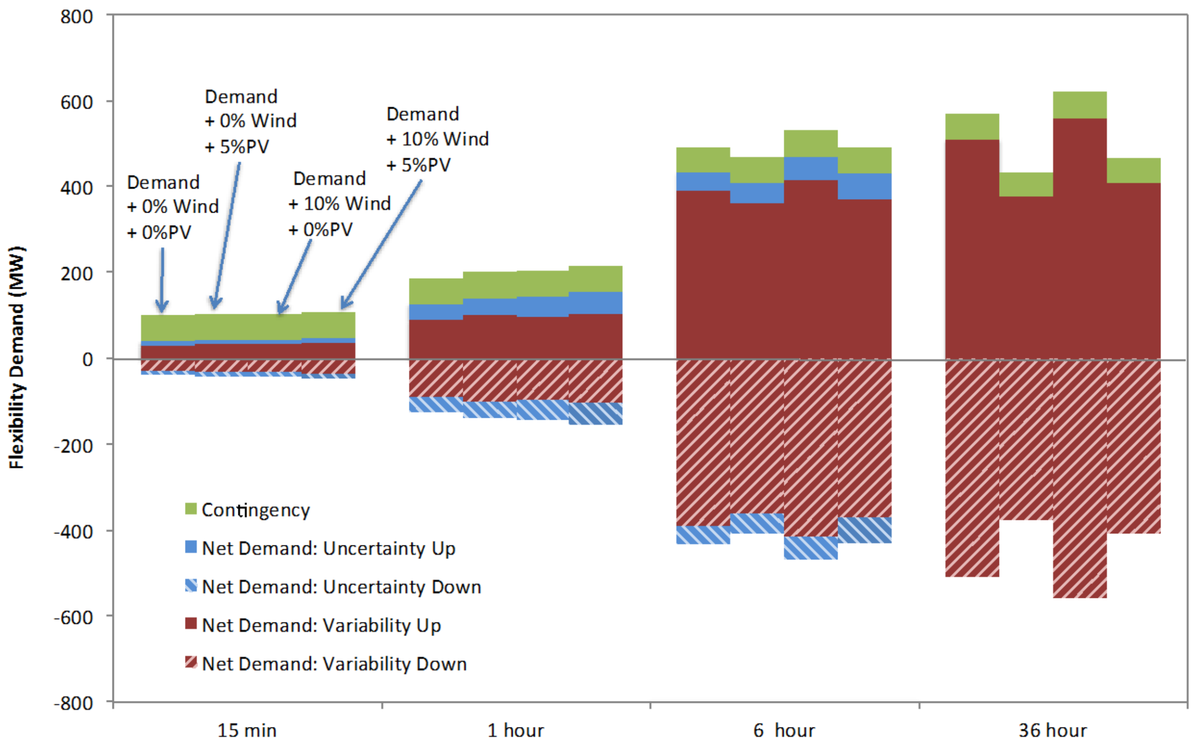


**Figure 4. Illustration of Flexibility Demand for Parameters Used in this Analysis**

### 3.2.2 Flexibility Supply Parameters

The flexibility supply parameters are derived from a wide range of sources specific to the western U.S. The parameters include thermal plant ramp rates, minimum generation levels, and start up and shut down times, typical dispatch of thermal generators during constrained periods, hydro ramping capability, transmission ramping capability, DR assumptions, and energy storage assumptions. Each of these is described in this section, and additional details are in Appendix B. In general, we err on the side of characterizing flexibility supply parameters based on the current use of elements in the power system, rather than attempting to project potential capabilities based on how the elements might be used in the future. This focus on the status quo leads to conservative estimates of the flexibility supply throughout the parameters described below.

The thermal plant ramp rates, minimum generation levels, and startup and shutdown times are derived from the WECC Common Case dataset (WECC 2014), with some modifications. The

WECC dataset includes unit-specific generator parameters for generation in WECC. Many generators have ramp rates of exactly 150, 160, or 320 MW/h, irrespective of the plant size. We deemed these entries to be anomalous and likely erroneous, and our primary modification was to remove them from the dataset. In addition, startup and shutdown times are not directly available in the WECC dataset; instead we use WECC's data on minimum up and down times to inform our startup and shutdown times.[29] We grouped the individual generators into generator types and then found the median value for ramp rate (in terms of percentage of capacity per hour), minimum generation level (in terms of percentage of capacity), and startup and shutdown times for all units of the same generator type.

Similar to the IEA methodology, another key parameter is the typical dispatch of the different generation types when the system is most constrained (Figure 5). For most of the western U.S., we follow the IEA assumptions and assume that the most constrained times are during peak-load and minimum-load periods. Minimum- and peak-load periods are identified based on the 1$^{st}$ and 99$^{th}$ percentiles of hourly load data between 2007 and 2012 from the Ventyx Velocity Suite (Ventyx 2014). However, in the PNW, thermal system dispatch also depends heavily on hydro dispatch. Hence, for the PNW, we identify the constrained low and high periods as the 1$^{st}$ and 99$^{th}$ percentiles of hourly load less hydro generation. To identify these periods, we used hourly load data from the Ventyx Velocity Suite and hourly hydro generation data from the Bonneville Power Administration (BPA) between 2007 and 2012.[30] We then used historical generator dispatch data during these constrained periods to classify generators into one of four states: off, minimum generation, mid-merit, and maximum generation. The historical generation data, retrieved from the Ventyx Velocity Suite, are based on the U.S. Environmental Protection Agency's Continuous Emissions Monitoring System (CEMS) dataset. For some of the generator types, e.g., hydro, we could not use this approach to estimate the typical dispatch; instead we used the original IEA assumptions or our own judgment.

IEA assumes that hydro is very flexible—able to ramp to full output within 15 min—but constraints on hydro operation in the West may limit its ability to provide flexibility. To develop hydro ramping parameters better suited to the region, we used historical hydro data from a 6-yr period to examine swings in hydro production at BPA. With this dataset we found that large swings in hydro did occur at the same time as large swings in demand, confirming that hydro can ramp in response to the need for flexibility. However, the maximum observed ramps over the four flexibility intervals were consistently less than the hydro capacity. We use the highest observed ramp over 15 min, 1 h, 6 h, or 36 h (at the 99$^{th}$ percentile) as a percentage of the highest sustained 18-h hydro production as the ramp rate of hydro (Table 5). These are conservative estimates of the ability of hydro to provide flexibility, because we rely on historical performance (future abilities could be greater if the need is greater than observed in the past), and we use the

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[29] For CTs, the WECC data indicated the minimum down times are 2 h. However, most values we found in the literature suggest startup times of 1 h or less for CTs. We therefore assume 1 h startup times for CTs and examine startup times of 15 min in the sensitivity analysis.

[30] Historical BPA hydro data were downloaded from: http://transmission.bpa.gov/Business/Operations/Wind/default.aspx.

99th percentile rather than the observed maximum.[31] We use the 99th percentile to ensure that the parameters are based on capabilities that have repeatedly occurred in the past and are not due to some single emergency or unique event. Hydropower resources identified as run-of-river (RoR) hydro have less ability to store water in a reservoir than conventional hydro. We reflect the limited ability of RoR hydro to supply flexibility by assuming a higher minimum generation level (and therefore a smaller range available to change generation levels) than conventional hydro while maintaining similar assumptions about ramp rates and typical dispatch levels.

The resulting conventional flexibility supply, as a percentage of the nameplate capacity of the resources, is illustrated in Figure 6. These values represent the culmination of the previously described parameters and assumptions and help to explain the results in the following sections.

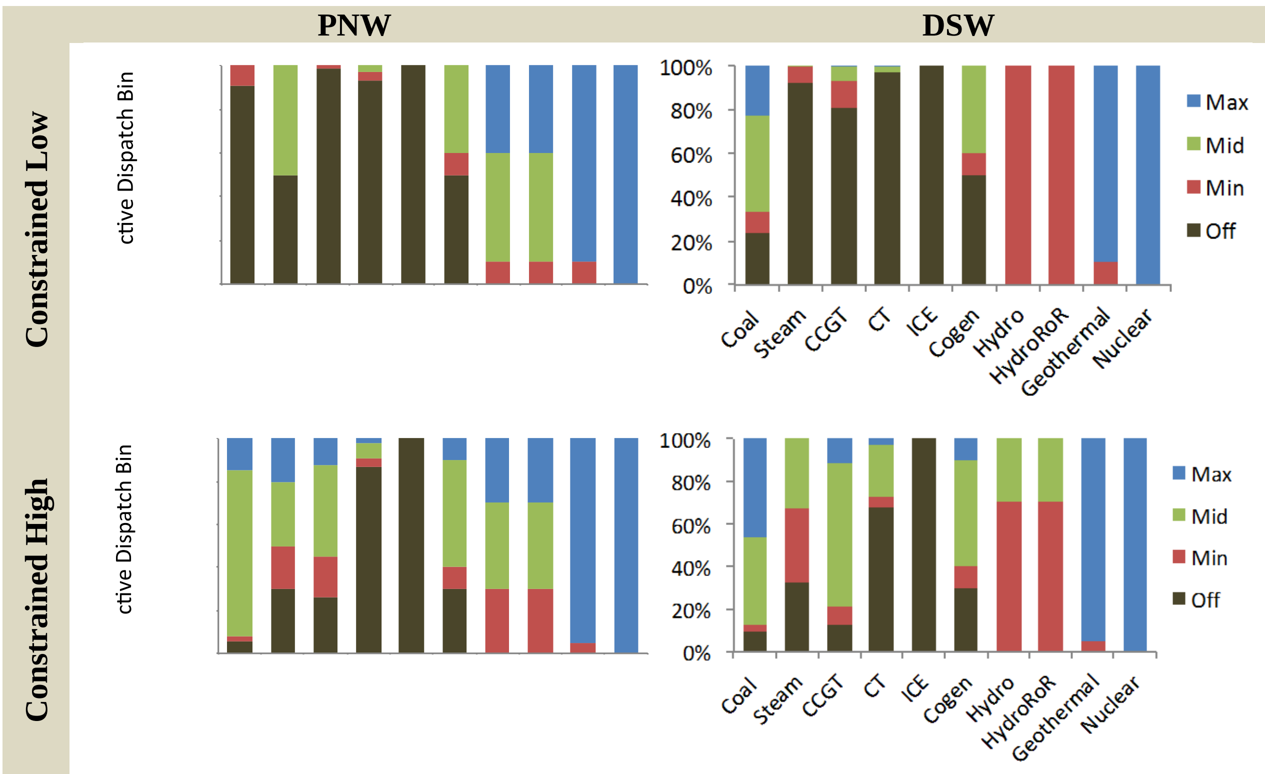



**Figure 5. Typical Dispatch Parameters Used for Utilities in the PNW and DSW**

**Table 5. Hydro Ramp Rates**

| Flexibility Interval | Maximum Ramp (% of hydro capacity) |
|---|---|
| **15 min** | 5% |
| **1 h** | 16% |
| **6 h** | 45% |
| **36 h** | 60% |

[31] Puget Sound Energy (PSE) indicates that their contracted hydro is very flexible over short time periods (PSE 2013). Our parameters will therefore understate the overall flexibility supply for PSE.

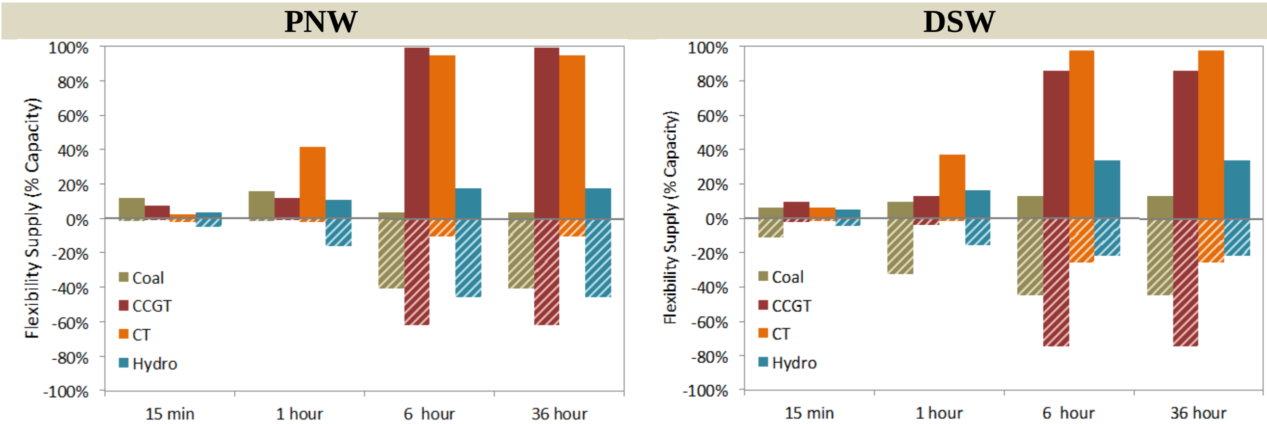



**Figure 6. Flexibility Supply Resulting from Parameters and Assumptions for Select Generation Types**

IEA assumes that transmission interconnections, like hydro, are very flexible—able to ramp to full output within 15 min—but resources on the other side of a transmission line may limit the ability to provide flexibility. To develop more refined estimates of the capability of the transmission interconnections with other electric systems, we examined changes in flows with 10 yr of hourly data for transmission lines into and out of the PNW region.[32] We used the 99$^{th}$ percentile of the change in transmission flows over 1, 6, and 36 h intervals as a percentage of the combined import plus export line limit (i.e., we assumed the largest possible ramp would involve switching from full export to full import or vice-versa). The resulting maximum transmission ramping capability in the up and down directions is shown in Table 6. Because we only had hourly data, we estimated the 15 min ramps as 25% of the observed hourly ramps.[33] The transmission ramping capability is conservative for the same reason the hydro ramping estimates are conservative.

**Table 6. Transmission Ramp Rates**

| Flexibility Interval | Maximum Ramp (% of combined line limit) |
|---|---|
| **15 min** | 2.6% (estimated) |
| **1 h** | 10% |
| **6 h** | 30% |
| **36 h** | 37% |

Transmission capacity is rarely reported in the IRP database, leading to an understatement of the transmission capacity between individual utilities and regions. To correct for this, we augment the IRP database with our own assumptions about transmission capacity. We allocate regional transmission capacity identified by E3 (Olson 2015) to utilities within those regions in proportion to peak demand in 2012. We assume that this transmission capacity does not change

[32] Historical transmission flow data were downloaded from: http://www.wiebgridtracker.com/. Because transmission capacity is an important flexibility supply parameter, the flexibility inventory analysis could be improved with more detailed forward-looking data that take transmission expansion and flow-path changes into account.
[33] We assume that transmission interconnections can provide sub-hourly flexibility based on the recent Federal Energy Regulatory Commission Order 764 that requires 15 min scheduling be offered to transmission customers.

in future years unless the IRP database explicitly includes additional transmission capacity as a resource.

The DR parameters are based on assumptions. We assume that DR programs identified in the IRP database as “direct load control” can be curtailed across all flexibility intervals. Based on analysis of direct load control programs with residential air conditioning (Sullivan et al. 2013), we assume that direct load control can be fully deployed within the 15 min flexibility interval. We assume DR programs identified as interruptible load can only curtail load (flexibility up) with a 30-min notification period (Cappers et al. 2012), which makes it available in the 1 h, 6 h, and 36 h intervals but not in the 15 min interval. Finally, all other DR is assumed to curtail load only (flexibility up) and to require a 24 h advance notice, which makes it only available in the 36 h flexibility interval.

As the majority of energy storage identified in the IRP database is pumped hydro storage, we use characteristics of pumped hydro to estimate the contribution of energy storage to flexibility supply. Based on a description of the operational characteristics of the Helms Pumped Hydro station in California (Yeung 2008), which reportedly can reach full deployment in 8 min, we assume energy storage can be fully deployed within the 15 min flexibility interval.

## 4. Results

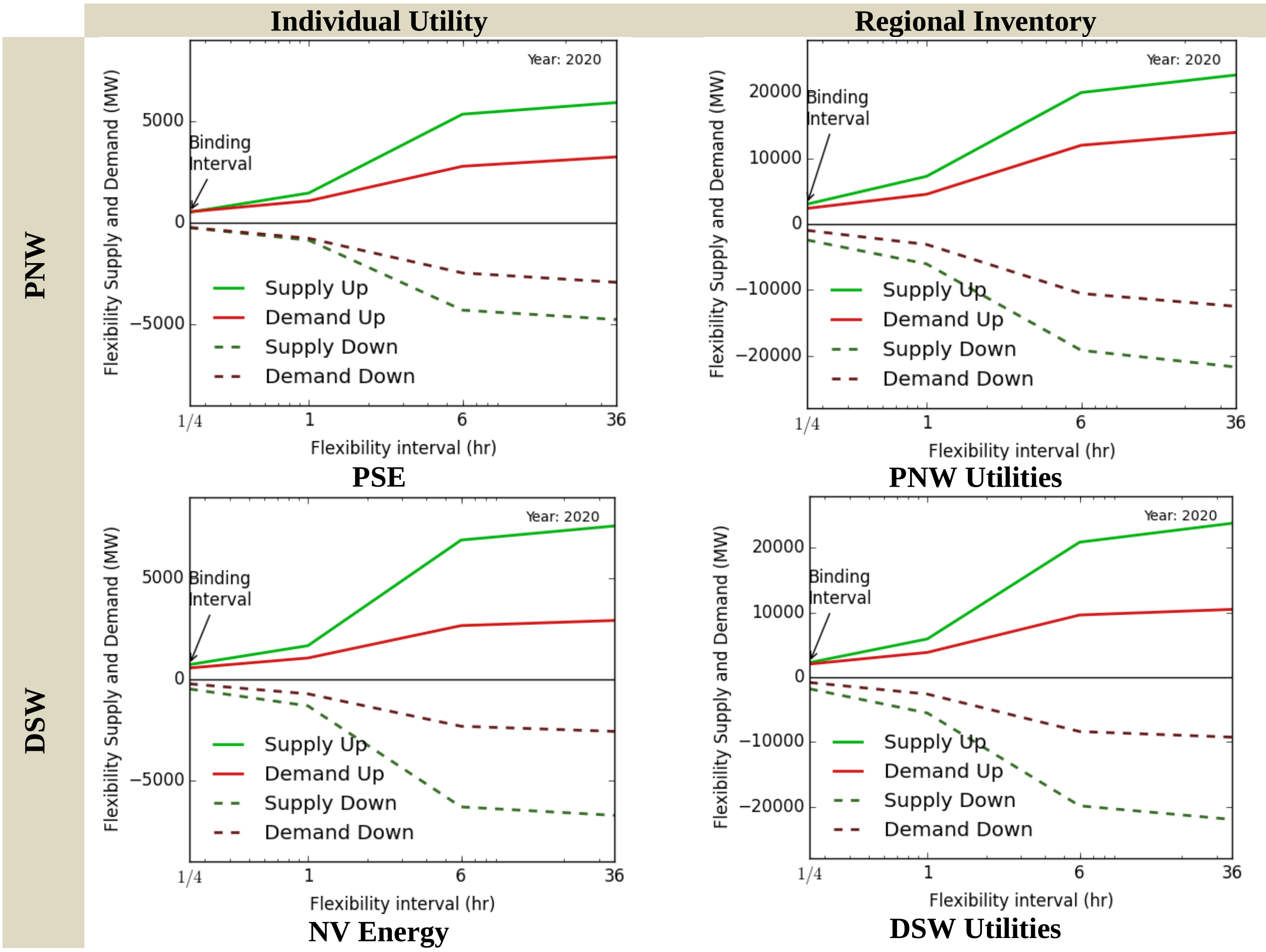
We applied the flexibility inventory methodology to the resources identified in the IRP database to create flexibility inventories for several example regions. The results begin with the flexibility inventory for a future year and the binding interval. Next the flexibility supply and demand in the binding interval and the resulting binding flexibility ratio are shown over the planning horizon. To clarify the results and the parameters that impact the outcome, we then present an analysis of the sensitivity of the binding flexibility ratio to changes in parameters and changes in the capacity of key resources.

### 4.1 Inventory for Year 2020

For any particular year, the flexibility inventory method can estimate the flexibility supply and demand across all flexibility intervals in both the up and down directions. The interval with the lowest ratio of flexibility supply to flexibility demand is the binding flexibility interval. The results of the flexibility inventory for the four examples are shown for 2020 in Figure 7. Each of the inventories shows the total estimated flexibility supply and demand in each of the four flexibility intervals in the up and down directions.

In each case, the flexibility interval with the lowest ratio of flexibility supply to flexibility demand, the binding interval, is 15 min in the up direction. In this interval, only online resources can contribute to flexibility supply, and we assume generators are being dispatched to meet peak-demand conditions in the DSW or high-demand/low-hydro conditions in the PNW. The demand for flexibility in this interval includes 15 min increases in load, 15 min decreases in wind and solar power, and the contingency reserves equivalent to 6% of peak demand.

Over the longer flexibility intervals, flexibility demand grows—particularly after 1 h—but so does flexibility supply. Flexibility supply increases in part owing to the ability to start up and shut down CTs and CCGTs.




Note: The x-axis, indicating the flexibility interval, is on a log scale.

**Figure 7. Flexibility Inventories for Selected Utilities and Regions in 2020**

Within the binding flexibility interval of 15 min in the up direction, we can identify the contribution of each resource to flexibility supply and demand in 2020 (Figure 8). Flexibility demand (made up of contingency reserves, variability in net demand, and uncertainty in net demand) is shown as a negative value, and flexibility supply is shown as a positive value. Across all four examples, the largest source of flexibility demand in the binding interval is the contingency reserve, followed by variability in net demand. The major suppliers of flexibility in the binding flexibility interval are transmission, CCGTs, coal, and CTs. In the PNW, pumped hydro storage and hydro (both reservoir and run-of-river) are also large sources of flexibility supply during the binding 15 min up flexibility interval. DR does not contribute to flexibility supply in the binding interval, because the type of DR included in IRPs requires more than a 15 min notification.

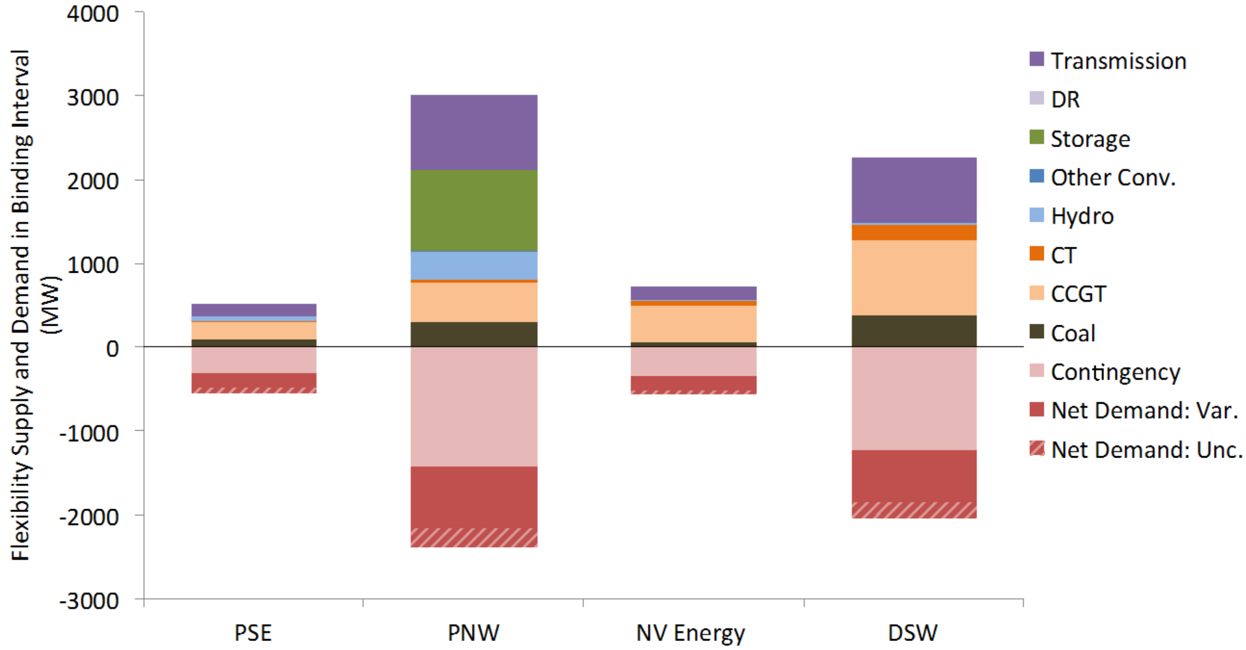


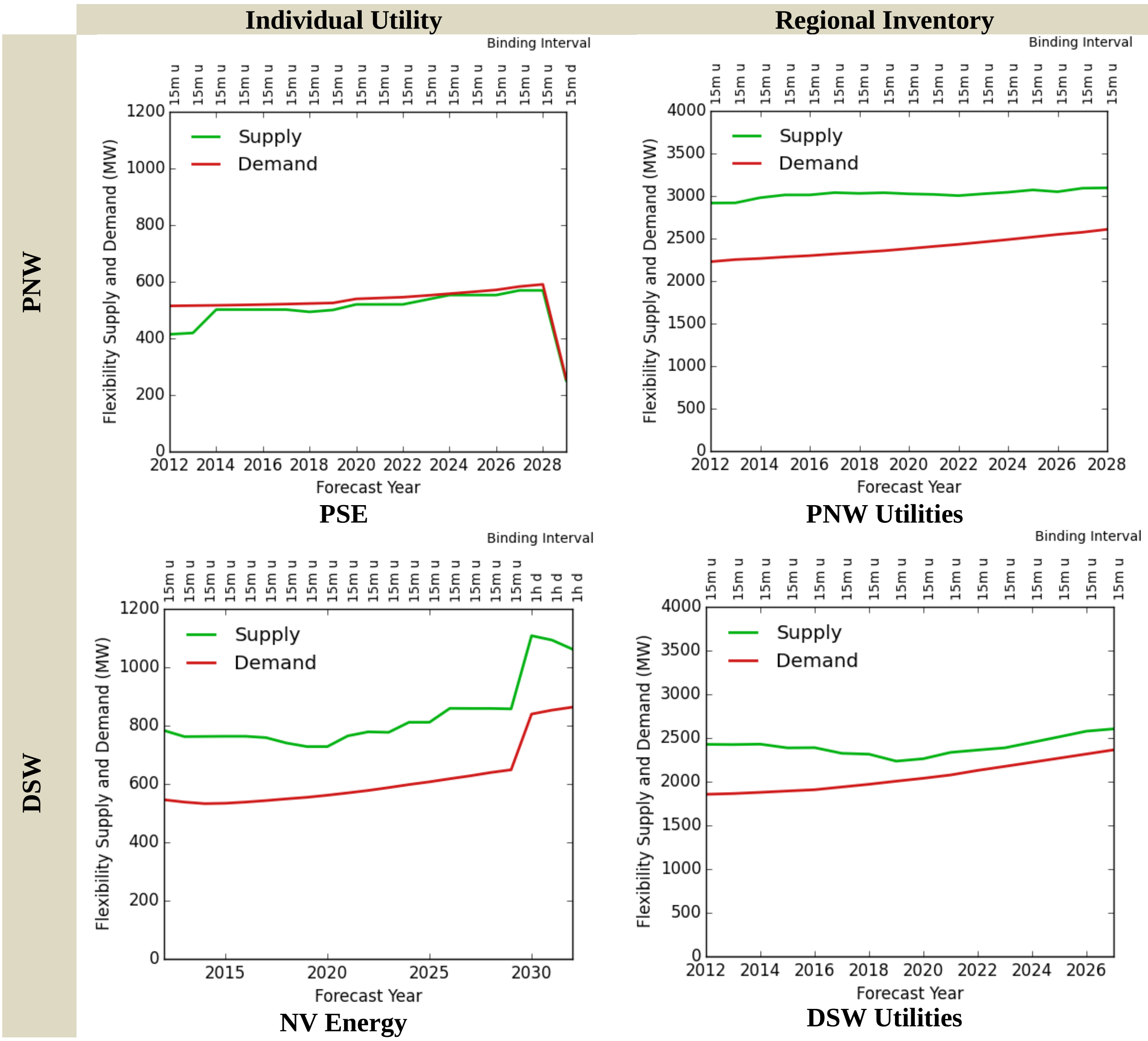

**Figure 8. Sources of Flexibility Supply and Demand in the Binding Flexibility Interval (15 min up) in 2020**

### 4.2 Flexibility Inventory over the Planning Horizon

The main advantage of connecting the flexibility inventory methodology to the IRP database is being able to assess trends in flexibility supply and demand over a planning horizon of 10–20 yr. The flexibility demand and supply in the binding interval over time is shown in Figure 9. In almost all cases, except the last years of the PSE and NV Energy inventory, the binding interval continues to be 15 min in the up direction. The implications are that (1) the shorter flexibility intervals are more critical than the longer flexibility intervals and (2) providing flexibility in the up direction is more important than the down direction. In the last year of the PSE inventory, the binding interval shifts to the 15 min down direction. The shift occurs largely because of planned CTs contributing more to flexibility supply in the up direction than the down direction. These new CTs increase the flexibility ratio in the 15 min up direction more than the flexibility ratio in the 15 min down direction, which causes the down direction to become the more binding constraint in 2029. A similar shift is caused by the planned addition of CTs to the NV Energy system in later years, which contribute more flexibility in the 15 min up direction then they do in the 1 h down direction.

In many cases the flexibility supply in the binding interval is relatively stable over time. However, the flexibility demand tends to increase with time as both demand and the share of variable renewable generation grows.

In the case of PSE, the flexibility supply is consistently below the flexibility demand.[34] At the same time, the larger grouping of PNW utilities shows a surplus of regional resources that can provide flexibility up in the 15 min interval. This result suggests that PSE could benefit from coordination with neighbors to ensure adequate flexibility.




Note: m = minutes; u = up; d = down.

**Figure 9. Flexibility Supply and Demand in the Binding Interval over the Planning Horizon**

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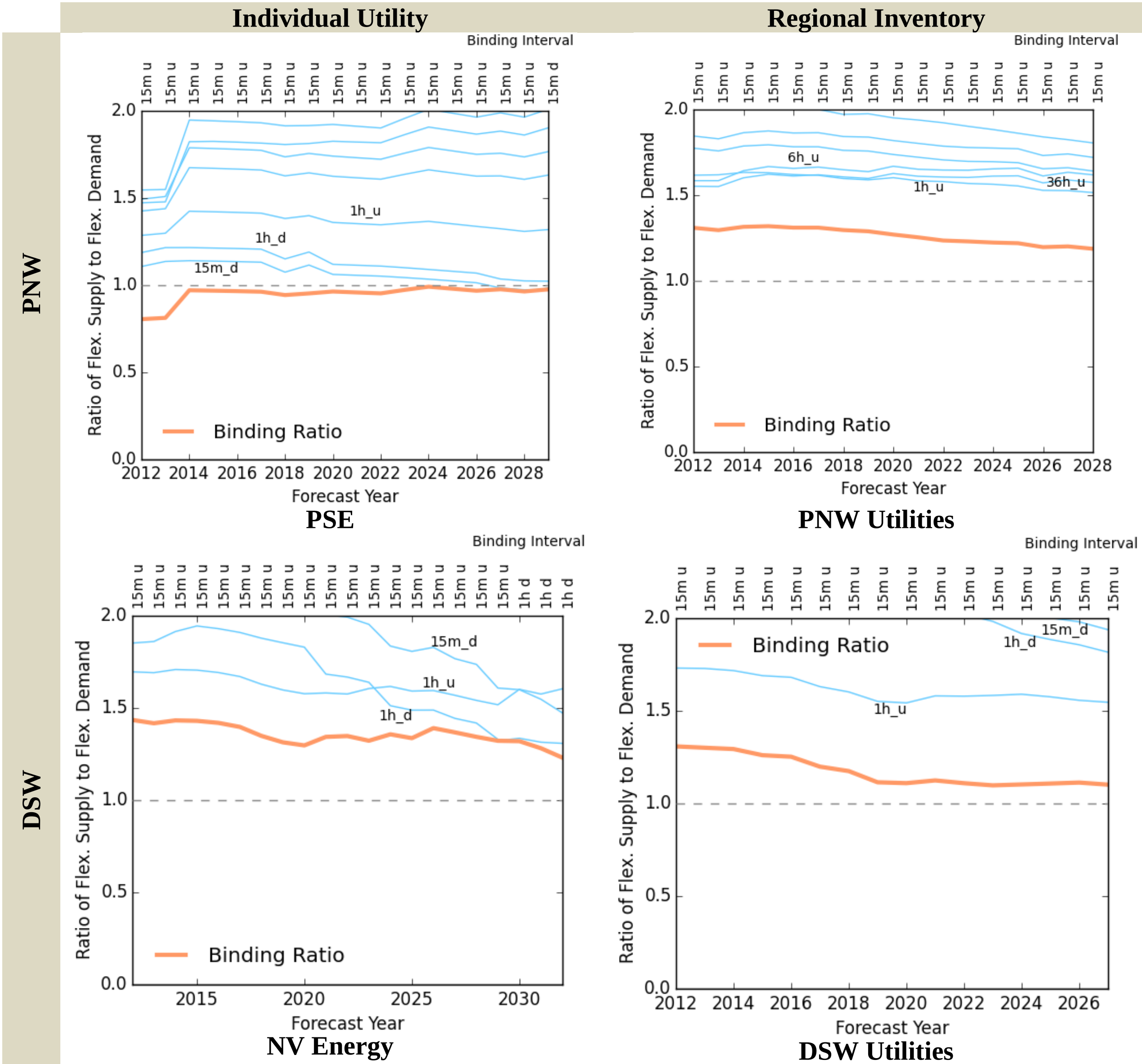
[34] In contrast, Puget Sound Energy's own analysis of flexibility supply and demand (PSE 2013) found flexibility supply was projected to exceed flexibility demand in future years. Of the many potential reasons for this difference, the main reasons are likely to be our more conservative estimation of hydro flexibility (which lowers our estimate of flexibility supply) and our more conservative estimate of the risk tolerance (which increases our estimate of flexibility demand). In addition, PSE uses an hour-ahead commitment to determine if CTs should be started to provide more flexibility. Our use of historical typical dispatch of CTs (which finds many CTs offline during times of need) and our base assumption of a 1 h start time also decrease our estimate of flexibility supply. We further explore these issues in the parameter sensitivity in Section 4.4.

For the PNW and DSW region, the binding constraint is always the 15 min up interval, and both show a flexibility surplus throughout the analyzed period.

### 4.3 Binding Flexibility Ratio

To illustrate the overall trend in flexibility with time, we plot the ratio of flexibility supply to flexibility demand in the binding interval (the binding flexibility ratio) in Figure 10. In addition to the binding flexibility ratio (the orange line), we also show the ratio of flexibility supply to demand in other intervals (light blue lines). Most charts show a declining binding flexibility ratio (indicating that managing the power system will become more challenging in future years), though the rate of change is gradual. The declining binding flexibility ratio suggests the increase in flexibility demand, from increasing load or increasing renewables, is faster than the increase in flexibility supply. In the case of PSE, the ratio is below one, and the ratio of flexibility supply to demand in the 15 min down interval decreases such that it becomes the binding interval in 2029. In the case of NV Energy, the ratio of flexibility supply to flexibility down in the 1 h down interval decreases in later years of the planning horizon to the point that it becomes the binding flexibility interval in 2030.




Note: m = minutes; h = hours; u = up; d = down.

**Figure 10. Binding Flexibility Ratio over the Planning Horizon**

The decreasing binding flexibility ratio suggests that additional sources of flexibility supply may be useful in the future. In these cases, the sources of flexibility that will be most helpful are those that can provide flexibility in the up direction in a short amount of time. Supplementary analysis that we conducted with higher shares of wind or PV found that, depending on the portfolio, the binding flexibility interval could switch to 15 min down, 1 h up, or 1 h down. Furthermore with very high shares of wind or PV the flexibility demand in the longer intervals also began to outstrip flexibility supply. So even though the shorter intervals (15 min and 1 h) were the binding flexibility intervals, the longer flexibility intervals also posed challenges.

## 4.4 Sensitivity Analysis

We conducted two types of sensitivity analyses: a parameter sensitivity, to understand which parameters have a significant impact on the resulting inventory, and a capacity sensitivity, to understand how much the flexibility inventory will change with the addition or removal of a similar amount of each resource.

### 4.4.1 Parameter Sensitivity

The sensitivity of the binding flexibility ratio in 2020 to various parameters is summarized in Figure 11 for PSE, the PNW utilities, NV Energy, and the DSW utilities. The dot shows the binding flexibility ratio using the base-case assumptions similar to the previous results. The sensitivity cases each vary one parameter at a time from the base case. The range represents the sensitivities that lead to the greatest increase or decrease in the binding flexibility ratio relative to the base case for each set of resources. The regional aggregations of utilities (PNW and DSW) are less sensitive to the different parameters than the individual utilities (PSE and NV Energy). This is most likely due to individual resources (e.g. CCGTs) contributing a smaller share of flexibility supply or demand for the regional aggregations than for individual utilities. At the extremes of the sensitivity range, the change in parameters primarily still results in the 15 min flexibility interval in the up direction being the binding interval with one case where it switches to 15 min in the down direction. Within the range some sensitivities result in the binding interval changing to the 15 min interval in the down direction or the 1 h interval in the up or down direction, though these occurrences are rare.

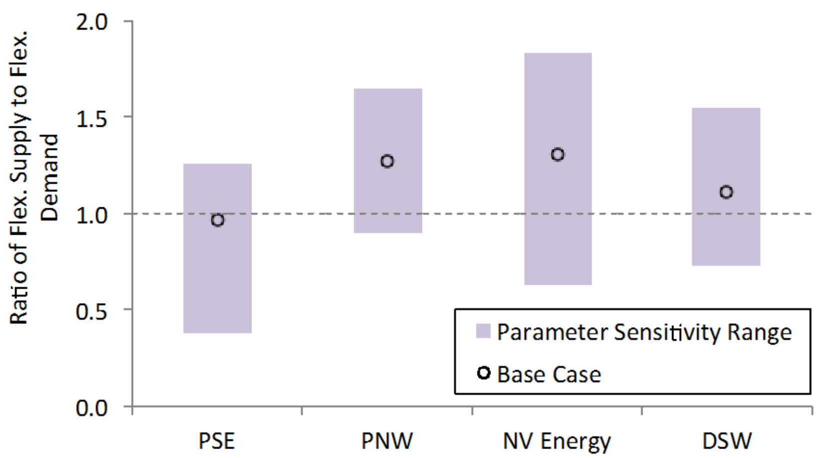



**Figure 11. Sensitivity of Binding Flexibility Ratio in 2020 to Various Parameters**

**Table 7. Sensitivity of Binding Flexibility Ratio in 2020 to Various Parameters**

| Parameter sensitivities | | (Base parameter) | (Change parameter) | PSE | PNW | NV Energy | DSW |
|---|---|---|---|---|---|---|---|
| Thermal | Coal | Start time (48 h) | Shorter (8 h) | 0.00 | 0.00 | 0.00 | 0.00 |
| | | Minimum generation (40%) | Lower (20%) | 0.00 | 0.00 | 0.00 | 0.00 |
| | | | Higher (55%) | 0.00 | 0.00 | 0.00 | 0.00 |
| | | Ramp rate (60%/h) | Faster (100%/h) | 0.05 | 0.04 | 0.04 | 0.07 |
| | | | Slower (30%/h) | -0.08 | -0.06 | -0.05 | -0.09 |
| | | Typical dispatch (Fig. 5) | IEA dispatch | -0.15 | -0.12 | -0.10 | -0.16 |
| | CCGT | Start time (4 h) | Shorter (1 h) | 0.00 | 0.00 | 0.00 | 0.00 |
| | | Minimum generation (55%) | Lower (30%) | 0.00 | 0.00 | 0.00 | 0.00 |
| | | | Higher (60%) | 0.00 | 0.00 | 0.00 | 0.00 |
| | | Ramp rate (50%/h) | Faster (100%/h) | 0.10 | 0.09 | 0.23 | 0.13 |
| | | | Slower (30%/h) | -0.16 | -0.08 | -0.31 | -0.18 |
| | | Typical dispatch (Fig. 5) | IEA dispatch | -0.33 | -0.17 | -0.67 | -0.38 |
| | CT | Start time (1 h) | Shorter (15 min) | 0.16 | 0.25 | 0.53 | 0.44 |
| | | | Longer (2 h) | 0.00 | 0.00 | 0.00 | 0.00 |
| | | Minimum generation (45%) | Lower (25%) | 0.01 | 0.01 | 0.04 | 0.03 |
| | | | Higher (60%) | -0.01 | -0.01 | -0.03 | -0.03 |
| | | Ramp rate (300%/h) | Faster (840%/h) | 0.00 | 0.00 | 0.00 | 0.00 |
| | | | Slower (90%/h) | -0.01 | 0.00 | -0.01 | -0.01 |
| | | Typical dispatch (Fig. 5) | IEA dispatch | 0.16 | 0.09 | 0.18 | 0.14 |
| | ICE | Start time (1 h) | Shorter (15 min) | 0.00 | 0.01 | 0.00 | 0.00 |
| Hydro | Reservoir | Minimum generation (25%) | Lower (10%) | 0.00 | 0.00 | 0.00 | 0.00 |
| | | | Higher (50%) | 0.00 | 0.00 | 0.00 | 0.00 |
| | | Ramp rate (Table 5) | Faster (Double) | 0.02 | 0.00 | 0.00 | 0.00 |
| | | | Slower (Halve) | -0.01 | 0.00 | 0.00 | 0.00 |
| | | Typical dispatch (Fig. 5) | IEA dispatch | 0.01 | 0.00 | 0.00 | 0.00 |
| | RoR | Minimum generation (50%) | Lower (10%) | 0.00 | 0.00 | 0.00 | 0.00 |
| | | | Higher (75%) | 0.00 | 0.00 | 0.00 | 0.00 |
| | | Ramp rate (Table 5) | Faster (Double) | 0.06 | 0.13 | 0.02 | 0.01 |
| | | | Slower (Halve) | -0.03 | -0.07 | -0.01 | 0.00 |
| | | Typical dispatch (Fig. 5) | IEA dispatch | -0.10 | 0.06 | 0.00 | 0.00 |
| Energy Storage | | Ramp rate (750%/h) | Faster (1500%/h) | 0.00 | 0.00 | 0.00 | 0.00 |
| | | | Slower (375%/h) | 0.00 | -0.03 | 0.00 | 0.00 |
| Demand response | | Controllability (Table 3) | Full control for all | 0.23 | 0.10 | 0.50 | 0.43 |
| | | | No notification for all | 0.10 | 0.10 | 0.50 | 0.43 |
| | | | Bi-directional for all | 0.00 | 0.00 | 0.00 | 0.00 |
| Transmission | | Ramp rate (Table 6) | Faster (Double) | 0.30 | 0.37 | 0.28 | 0.38 |
| | | | Slower (Halve) | -0.25 | -0.19 | -0.14 | -0.19 |
| | | | No Subhourly | -0.59 | -0.37 | -0.28 | -0.38 |
| Flexibility demand | | Risk tolerance (3-sigma) | More tolerant (2-sigma) | 0.16 | 0.20 | 0.20 | 0.17 |
| | | | Less tolerant (4-sigma) | -0.17 | -0.15 | -0.15 | -0.13 |

| Decreases Flexibility | No Impact on Flexibility | Increases Flexibility |
|---|---|---|

The particular sensitivity cases and results are detailed in Table 7. Each row represents the sensitivity when one parameter is changed relative to the base-case assumptions presented in previous sections. The change in the binding flexibility ratio is then presented such that a positive change (highlighted with blue) represents an increase in flexibility supply relative to flexibility demand. A negative change (highlighted with red) represents a decrease in flexibility supply relative to demand. The ranges of parameters were chosen to reflect the range of parameters described by other sources in the literature (e.g., Fenton 1982, GE Energy 2010a, Lew et al. 2013, Koch 2013, Makarov et al. 2008, Mills et al. 2013, Schroeder et al. 2013) or other reasonable assumptions.

The binding flexibility ratio is highly sensitive to only a few parameters, as shown by the narrow bands of bold blue and red. These sensitivity results are very much driven by the binding interval being 15 min in the up direction. The key parameters that increase flexibility supply in the binding interval include shorter start-up times for CTs (15 min instead of 1 h), changes to the assumed dispatch status of CTs (using the IEA assumptions[35] instead of the typical dispatch parameters derived for each region from historical data; see Section 3.2.2), and faster ramp rates for coal and CCGTs. Removing the notification requirement for DR ("No notification for all") or making DR fully controllable ("Full control for all" - both removing the notification requirement and requiring all DR to decrease and increase load) would also increase the flexibility supply, as would faster ramp rates of transmission interconnections (doubling of the ramp rate capability across all flexibility intervals). In addition, the binding flexibility ratio increases if the decision maker is more risk tolerant, which lowers the flexibility demand (use of two standard deviations of the net demand instead of three).

The key parameters that decrease flexibility supply in the binding interval include slower ramp rates for flexibility supply accessed via transmission (halving the ramp rate or preventing any sub-hourly transmission interchanges), slower ramp rates for coal and CCGTs, alternate assumptions for the typical dispatch of coal and CCGTs during constrained periods,[36] and a lower risk tolerance of the decision maker. The fact that the results are highly sensitive to the typical dispatch of thermal generators during constrained periods indicates that production-cost models or other dispatch tools may be needed to improve estimates of flexibility metrics.

Parameters that the results are sensitive to are common across all regions in most cases, with the exception of RoR hydro parameters, which only affect the PNW substantially. RoR hydro is common in the PNW and relatively uncommon in the DSW. RoR hydro would contribute more to flexibility supply if its ramp rate were faster than assumed based on analysis of historical hydro ramping at BPA. RoR hydro would contribute less with a slower ramp rate or typical dispatch based on the IEA assumptions.

[35] IEA assumptions for typical dispatch of CTs are as follows: in the constrained high period 20% of CT capacity is offline, 30% is near minimum generation, 30% is near the middle of its generation range, and 20% is near maximum generation; in the constrained low period 70% of the CT capacity is offline, and 30% is near minimum generation levels.

[36] IEA assumptions for typical dispatch of CCGTs are as follows: in the constrained high period 10% of CCGT capacity is offline, 10% is near minimum generation, and 80% is near maximum generation; in the constrained low period 10% of the CCGT capacity is offline, 40% is near minimum generation levels, and 50% is near the middle of its generation range.

The table's large light-colored and white areas show where different parameter choices have little or no impact on the binding flexibility ratio. For example, there is little value in further refining the estimates for parameters such as minimum generation levels for coal, CCGTs, CTs, and hydro or for startup times for coal and CCGTs, because the binding flexibility ratio changes little or not at all over a wide range of parameter choices when the binding interval is 15 min in the up direction. There is also little value in just making DR bi-directional ("Bi-directional for all")[37] without decreasing the notification time since DR can already curtail load (i.e. provide flexibility up) in the base case.

### 4.4.2 Capacity Sensitivity

Another way to show the sensitivity of the flexibility inventory is to increase or decrease the amount of resources in the inventory. Whereas the parameter sensitivity helps clarify the importance of assumptions and data, this capacity sensitivity helps to understand which resources contribute most to improving the binding flexibility ratio. In this sensitivity analysis, we keep all parameters the same as in the base case, but we increase or decrease the capacity of each individual resource by 1% of the peak demand and measure the resulting change in the binding flexibility ratio. Changes to the merit order and associated typical dispatch levels of the generators are, however, not modeled. To gauge the relative importance of flexibility in generation, we also include the addition of quick-start (15 min start time) CTs and ICEs. The ranges of the binding flexibility ratio with changes in the capacity of individual resources are shown in Figure 12.

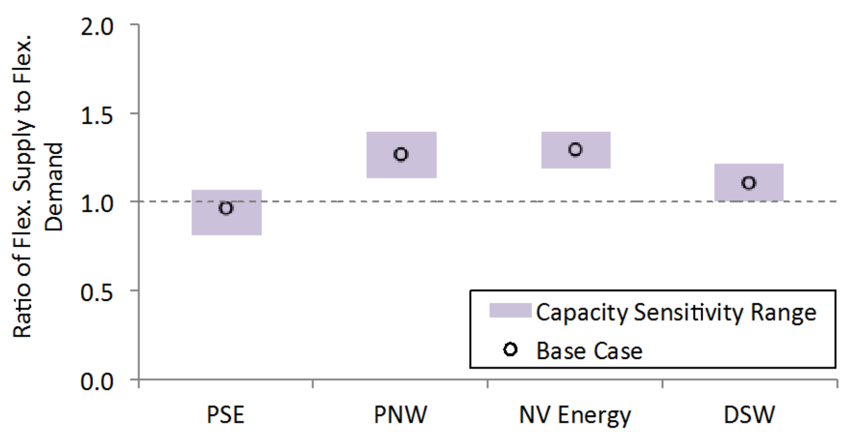



**Figure 12. Sensitivity of Binding Flexibility Ratio in 2020 to Changes in Capacity of Various Resources**

Changes in the binding flexibility ratio with changes in each individual resource (including load as well as wind and solar capacities) are summarized in Table 8. The two resources that produce the greatest change are energy storage and DR available via direct load control; quick start CTs and ICEs are also found to have a substantial impact. Relatively minor impacts are associated

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[37] The Bi-directional for all sensitivity makes the assumption that all demand response resources can both increase or decrease load in response to system needs.

with hydro, coal, CCGTs, non-quick-start CTs, and transmission. Changing coal capacity has a larger impact than changing non-quick-start CT capacity in the PNW because a larger fraction of coal is assumed to be online but below maximum output relative to CTs. Because a large fraction of CT capacity is offline, and its start time is assumed to be longer than 15 min, adding CT capacity does not make as big of a contribution to flexibility supply. Similarly the ICE contributes very little flexibility supply over 15 min, because most of the capacity is assumed to be offline, and the start time is assumed to be longer than 15 min. ICEs and CTs that could start in less than 15 min (quick start) contribute more to flexibility supply in the binding interval than the non-quick-start CTs and ICEs but less than energy storage or direct-load-control DR. Finally, changing flexibility demand via load, wind, or solar has a modest impact compared with the impact of adding flexible resources like DR, energy storage, or quick-start generation. As before, all of these results are driven by the binding flexibility interval being 15 min in the up direction; a portfolio of resources with a different binding interval would have different capacity sensitivities. In particular we would expect quick start CTs, quick start ICEs, and direct load control (which we assume to provide only flexibility up) to all be less important for cases where the binding interval is in the down direction. In this case, resources that can increase demand (e.g. energy storage) or that are online and can further decrease generation (including renewables curtailment) would all be important resources.

**Table 8. Sensitivity of the Binding Flexibility Ratio in 2020 for Changes in Capacity of Various Resources**

| Capacity Sensitivities | | | PSE | PNW | NV Energy | DSW |
|---|---|---|---|---|---|---|
| Thermal | Coal | Inc. | 0.01 | 0.02 | 0.01 | 0.01 |
| | | Dec. | -0.01 | -0.02 | -0.01 | -0.01 |
| | CCGT | Inc. | 0.01 | 0.01 | 0.01 | 0.01 |
| | | Dec. | -0.01 | -0.01 | -0.01 | -0.01 |
| | CT | Inc. | 0.00 | 0.00 | 0.01 | 0.01 |
| | | Dec. | 0.00 | 0.00 | -0.01 | -0.01 |
| | Quick Start CT | Inc. | 0.07 | 0.09 | 0.06 | 0.06 |
| | ICE | Inc. | 0.00 | 0.00 | 0.00 | 0.00 |
| | | Dec. | 0.00 | 0.00 | 0.00 | 0.00 |
| | Quick Start ICE | Inc. | 0.06 | 0.08 | 0.06 | 0.06 |
| Hydro | Reservoir | Inc. | 0.00 | 0.01 | 0.01 | 0.01 |
| | | Dec. | 0.00 | -0.01 | -0.01 | -0.01 |
| | RoR | Inc. | 0.00 | 0.01 | 0.01 | 0.01 |
| | | Dec. | 0.00 | -0.01 | -0.01 | -0.01 |
| Energy Storage | | Inc. | 0.11 | 0.13 | 0.11 | 0.11 |
| | | Dec. | -0.15 | -0.13 | -0.11 | -0.11 |
| Demand Response | Other DR | Inc. | 0.00 | 0.00 | 0.00 | 0.00 |
| | | Dec. | 0.00 | 0.00 | 0.00 | 0.00 |
| | Direct Load Control | Inc. | 0.10 | 0.13 | 0.11 | 0.11 |
| | | Dec. | -0.11 | -0.13 | -0.11 | -0.11 |
| Transmission | | Inc. | 0.01 | 0.01 | 0.01 | 0.01 |
| | | Dec. | -0.01 | -0.01 | -0.01 | -0.01 |
| Flexibility Demand | Load | Inc. | 0.00 | -0.01 | -0.01 | -0.01 |
| | | Dec. | 0.00 | 0.01 | 0.01 | 0.01 |
| | Wind | Inc. | -0.01 | -0.01 | 0.00 | 0.00 |
| | | Dec. | 0.01 | 0.00 | 0.00 | 0.00 |
| | Solar | Inc. | 0.00 | 0.00 | 0.00 | 0.00 |
| | | Dec. | 0.00 | 0.00 | 0.00 | 0.00 |

Note: Inc. = Increase in Capacity;
Dec. = Decrease in Capacity

| Decreases Flexibility | No Impact on Flexibility | Increases Flexibility |
|---|---|---|

## 5. Discussion

This study demonstrates different ways the flexibility inventory can be used to assess flexibility in the context of planning and to identify follow-up actions that planners and regulators can take. In this section, we use the results to answer a number of relevant questions. However, it is important to note that answers to such questions will differ depending on the particular IRP or group of IRPs considered. The answers provided here reflect the specific IRPs that we evaluated and are not meant to be generalizations. As a reminder, the frequently used flexibility terms are defined in Text Box 1.

**Text Box 1. Definitions of Flexibility Terms.**

| | |
|---|---|
| **Flexibility supply**: | Capability of generation or demand to change in response to system conditions over various time scales relevant to power system operations. |
| **Flexibility demand:** | Amount that the net demand will change over those different time scales, the degree to which those changes can be predicted ahead of time, and the contingency reserves. |
| **Flexibility up:** | Ability of the system to increase generation or decrease demand for electricity when needed. |
| **Flexibility down:** | Ability of the system to decrease generation or increase demand for electricity when needed. |
| **Binding interval**: | Flexibility interval and direction for which the ratio of the flexibility supply to flexibility demand is the lowest (most constrained). |
| **Binding flexibility ratio:** | Ratio of flexibility supply to flexibility demand in the binding interval. |

*Are fast or slow sources of flexibility likely to be more important?*

Some resources, such as energy storage or DR from direct load control, can provide fast response but potentially for a limited duration, whereas other resources, such as CCGTs can provide flexibility over longer periods. Which resource is more useful depends on the binding flexibility interval.

Our results show that flexibility demand is greatest over the longer intervals, but the short flexibility intervals constitute the binding intervals (most constrained) owing to the limited flexibility supply. In this case, fast sources of flexibility are more important than slower ones in determining the degree of surplus flexibility.

*Is more flexibility needed in one direction over the other?*

Some resources can only provide flexibility in one direction, or they provide it more easily or cheaply in one direction. For example, in our base case assumptions DR can provide flexibility in the up direction (through load curtailment), but it does not provide flexibility down. In contrast, wind or solar curtailment can more easily provide flexibility down than it can provide flexibility up.

Our results show that flexibility up is more important in the majority of cases owing to the contingency reserve requirements that increase flexibility demand in the up direction. Thus, sources of flexibility in the down direction, such as renewables curtailment, are less helpful for addressing flexibility in the binding flexibility interval than are sources of flexibility in the up direction. With higher shares of variable renewables, however, flexibility in the down direction may become the more important direction, in which case renewables curtailment or other sources of downward flexibility will be useful.

*With planned additions and retirements, is flexibility likely to become more or less important than it is today?*

Changes might occur over time in sources of flexibility supply (e.g., plant retirements or additions) and increases in flexibility demand with increasing shares of variable renewables. The trend in the binding flexibility ratio and the binding interval with time can gauge the changing level of difficulty in managing the system.

Our results all show relatively gradual changes with time, with most showing a decreasing ratio of flexibility supply to demand and the 15 min up interval as the binding flexibility interval. The gradual decrease indicates that providing flexibility will be more important in the future. It does not, however, indicate a need for the dramatic changes that would be called for by a precipitous decline in the ratio of flexibility supply to demand.

*Are there opportunities to coordinate with neighbors to improve flexibility?*

If one utility has a low ratio of flexibility supply to demand (near or below 1), while a nearby utility has a high ratio (greater than 1), then coordination between the two utilities may alleviate the need to build new sources of flexibility. A difference in the ratio of flexibility supply to demand between IRPs indicates opportunities for such collaboration.

Our results show that the PNW group of utilities consistently has a higher binding flexibility ratio than the PSE utility. Thus, collaboration between PSE and utilities in the PNW might increase PSE's flexibility supply within the binding flexibility interval of 15 min in the up direction. In the DSW, the similar binding flexibility ratios for NV Energy and the DSW group of utilities suggests more limited opportunities for collaboration.

*What kind of resources can contribute to flexibility supply when it is most needed?*

For cases in which the binding flexibility ratio is decreasing, one option is to identify resources that can contribute to flexibility supply. Our capacity sensitivity analysis shows that resources providing flexibility in the up direction over a short time interval are the most helpful for increasing flexibility supply when it is needed most. In contrast, resources that are typically offline and cannot start quickly enough or resources that have too long of a notification period will not be as helpful. For cases where the binding flexibility interval is in the down direction (e.g., some portfolios with higher shares of variable renewables) resources that can provide flexibility down, such as energy storage, generation that is typically dispatched above its minimum generation level or can turn off quickly, or renewables curtailment, will be helpful.

*What types of questions is the Flexibility Inventory NOT equipped to answer?*

The flexibility inventory is not appropriate for answering some questions. For example, it cannot indicate which sources of flexibility are most cost effective, because it does not account for the economics of flexibility supply and demand. It is also unsuited to identifying the quantity of flexibility supply needed in a particular year, because it only provides a high-level assessment of trends over longer periods. Determining whether a particular resource is needed for flexibility would require a more detailed analysis. Finally, the resources that might offer flexibility may offer a number of other economically attractive services to the electricity system: even if a resource is not found effective at mitigating a binding flexibility constraint, it may still be an economically attractive resource for other reasons.

## 6. Conclusions and Future Work

This analysis demonstrates an approach for creating a flexibility inventory that is similar to the IEA method and can be applied to resources included in an IRP. The approach uses only the type and capacity of the resources from the IRP along with a large set of externally defined parameters. The choice of a refined IEA methodology keeps the process for creating an inventory simple: no other model is required to conduct a new analysis. This means that the inventory can be continually updated in an automated fashion as new IRPs are released.

With case studies of four different utilities/regions, we found that the flexibility demand is greatest over longer flexibility intervals (greater than 6 h). Flexibility demand increases owing to the larger variability and uncertainty of load, wind, and solar over longer flexibility intervals. At the same time, the flexibility supply is also greatest over these longer intervals. The flexibility supply increases as dispatchable resources can ramp more, more generation can start up or shut down, and DR resources with a long notification interval can respond over the longer flexibility intervals. As such, even though flexibility demand is greatest over longer periods, the 15 min flexibility interval in the up direction is almost always the binding interval, because flexibility supply is more constrained in the shorter intervals than in the longer intervals. The combination of load, wind, solar, and contingency reserves contributes to the flexibility demand for the 15 min flexibility interval in the up direction. The flexibility supply, however, is limited to ramping of online generation (the base-case assumptions assume no generation can start within 15 min), intra-hour transmission interchange, energy storage, or DR with direct load control. With higher shares of variable renewables flexibility in the down direction can sometimes also be the limiting factor.

For three of the four utilities/regions, the binding flexibility ratio decreases consistently over the planning horizon of more than a decade. The relatively gradual decline indicates that utilities will likely gain experience with increasingly tight margins between flexibility supply and demand, which will allow them to adjust their plans to mitigate challenges. Of the utilities/regions we studied, PSE has the lowest binding flexibility ratio; because the group of PNW utilities has a substantially larger ratio, the possibility exists for PSE to draw on the excess flexibility supply of its neighbors to improve its ratio.

Sensitivity analysis indicates that some parameters are particularly important to estimating the ratio of flexibility supply to demand over the binding 15 min interval. A number of the key parameters are based on thermal plant limits such as ramp rates for coal and CCGTs and startup times for CTs. It should be relatively straightforward to make these parameters match actual operation more accurately for particular areas of interest. Other parameters are at least as important but are harder to refine, requiring considerable judgment on the part of the analyst. The parameters that define the typical dispatch of coal, CCGTs, and CTs all have a large impact on the binding flexibility ratio, but these parameters must be based on external analysis of generation dispatch during highly constrained periods. One limitation of the current method is that these dispatch patterns are expected to change both with traditional merit-order changes due to adding conventional capacity and with growing shares of variable renewables, while the typical dispatch parameters used in this analysis are based on historical observations. Furthermore, system operators may be able to position generation proactively during constrained times to ensure greater flexibility. This could require moving generation away from its typical dispatch pattern, which might otherwise be the most economic. Such considerations are beyond what can be evaluated in the flexibility inventory, but they are potential solutions that can be assessed with more detailed analysis.

Similarly, parameters for transmission ramp rates and the controllability of DR make a large difference. The transmission ramp rate parameters are difficult to define, because the most important factor is the mix of dispatchable generation on the other side of transmission constraints—that is, the ability of neighboring utilities to provide or receive electricity supply will constrain the transmission ramp rate. Expansion of the Energy Imbalance Market in the West may provide a mechanism for better accessing flexibility supply across transmission interfaces, leading to larger ramp rates across transmission lines than observed in the past. This will increase flexibility supply and, based on the results of the parameter sensitivity analysis, may significantly increase the binding flexibility ratio. DR parameters depend on the design of the DR program and the technology used to provide the response. Improved DR programs with increased controllability can increase the binding flexibility ratio. The risk tolerance of decision makers also affects the binding flexibility ratio: the greater the risk tolerance—that is, the lower the worst net-demand ramp and forecast error that is to be managed—the higher the ratio.

An analysis of the binding flexibility ratio's sensitivity to changes in resource capacity shows that increasing the amount of direct load control, energy storage, and quick-start CTs and ICEs substantially increases flexibility supply over the 15 min flexibility interval. Increasing the capacity of other technologies—such as coal, CCGTs, CTs, and hydro—produces a smaller increase in the binding flexibility ratio, because historically these resources have been dispatched in a way that would now allow for additional flexibility. If the new resources are not dispatched in the same way, the contribution to flexibility could be different. The simple WECC flexibility metric described in the introduction only considers CT and hydro generation as a source of flexibility, whereas our analysis identifies additional resources that can contribute to flexibility supply over the 15 min flexibility interval. More comprehensive accounting of flexibility inventories, such as our approach or others being developed, may help identify additional potential solutions.

The following are potential directions for future work related to the flexibility inventory:

*Extending applications of the current methodology to additional IRPs*—In addition to the examples assessed here, more IRPs are available in the RPP and new IRPs are continually added. We can apply the flexibility inventory to these IRPs and continue to better integrate the flexibility inventory with the RPP. Beyond IRPs in the western U.S., the flexibility inventory could be applied to any database of IRPs if other regions were also interested in tracking flexibility trends.

*Improving parameters used in the flexibility inventory methodology*—Sensitivity analysis indicates that variations in several parameters—including CT start times, ramp rates for CCGTs and coal units, DR capabilities, and transmission ramp rates—have a significant impact on the binding flexibility ratio. Thus, improving the accuracy of these parameters is important for ensuring the most credible and useful results. Additional work in this area might include gathering utility-specific estimates of parameters from IRPs or other publicly available sources.

*Validating the flexibility inventory methodology*—This study refined and applied an IEA flexibility methodology to western IRPs, but neither the IEA methodology nor our current modifications to it have been validated through a detailed analysis. Future validation work could gauge the accuracy of our methodology and identify weaknesses. In particular, the use of "typical dispatch" parameters in determining the flexibility supply from conventional resources must be examined; moreover, the selection of times that are most constraining for each flexibility interval (which is consequently used to estimate the typical dispatch) is based on engineering judgment rather than detailed analysis. Validation work should verify whether these constrained periods remain appropriate as variable-renewable capacity increases, and it should examine the impact on typical dispatch parameters of adding new generation capacity or retiring old generators. Another aspect of the methodology that should be evaluated is the assumption that resources on the other side of transmission interconnections can provide flexibility when needed. Finally, the IEA methodology focuses primarily on managing variability and uncertainty, but it does not directly address concerns about periods of over-generation caused by high shares of variable renewables. Validation should determine if the current methodology, which accounts for minimum generation and shutdown time constraints, adequately reflects challenges with over-generation for high shares of variable renewables, and it should investigate what additional parameters must be added.

One approach for validating the methodology would be to apply a more detailed flexibility supply and demand quantification technique like the one described by Zhao et al. (2015),[38] along with the current methodology, to various sets of resources. The validation could use sub-hourly load and variable renewables data and a production-cost model to commit and dispatch resources economically. The approach outlined by Zhao et al. (2015) could then be applied to estimate the maximum capability of the system to respond to uncertainty (flexibility supply) and the maximum uncertainty in net demand over the operating horizon (flexibility demand). We expect that the ratio of flexibility supply to demand would be smallest in the direction and over the operating horizon predicted by the binding flexibility interval in the current methodology. We also expect the detailed methodology would find similar trends over time in the binding flexibility ratio as predicted by our methodology.

*Improving the flexibility inventory methodology*—Depending on the insights gained from the validation of the current methodology, the next step would be to enhance our current approach to better generate insights similar to a more detailed analysis like that in Zhao et al. (2015), while, to the extent possible, maintaining simplicity and transparency. Improvements may include, for example, adapting a reduced-form dispatch model to better estimate typical dispatch parameters as the mix of resources changes over the planning horizon, though the necessity of such a change would need to be determined via the validation.

[38] The IRRE method outlined by Lannoye et al. (2012a) could also be used to validate the current methodology, but the flexibility inventory bears more resemblance to the method outlined by Zhao et al. (2015).

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## Appendix A. 3-Sigma Approximation for Net Demand

The 3-sigma approximation of the variability and uncertainty of net demand is based on summing the variances of random, but correlated variables:

$$3\sigma_{nd} = 3\sqrt{\sigma_l^2 + \sigma_w^2 + \sigma_s^2 - 2\sigma_l\sigma_w\rho_{l,w} - 2\sigma_l\sigma_s\rho_{l,s} + 2\sigma_w\sigma_s\rho_{w,s}}$$

Where:
$\sigma_i$ is the standard deviation in megawatts of a resource *i* (and *i* is one of the following: *nd* – net-demand, *l* – load, *w* – wind, or *s* – solar)
$\rho_{i,j}$ is the correlation of between resource *i* and *j*

The variability and uncertainty parameters are normalized to the peak demand or capacity of the wind or solar resource, such that the standard deviation in the above formula depends on the size of the resource:

$$\sigma_i = s_i K_i$$

Where:
$s_i$ is the normalized standard deviation (fraction of peak demand or nameplate capacity)
$K_i$ is the peak demand or capacity

Table 9 and Table 10 summarize the normalized parameters used to calculate the variability of net demand.[39] These were derived from the four high-resolution datasets for CAISO, APS, PGE, and PSCo.

**Table 9. Normalized Standard Deviation of Variability across Flexibility Intervals**

| | 15-min | 1-h | 6-h | 36-h |
|---|---|---|---|---|
| **Load** | 1% | 3% | 13% | 17% |
| **Wind** | 2% | 6% | 19% | 31% |
| **Solar** | 3% | 10% | 42% | 52% |

**Table 10. Correlation of Variability across Flexibility Intervals**

| | 15-min | 1-h | 6-h | 36-h |
|---|---|---|---|---|
| **Load, Wind** | -2% | -4% | -12% | -13% |
| **Load, Solar** | 11% | 14% | 42% | 69% |
| **Wind, Solar** | -8% | -14% | -29% | -27% |

[39] A limitation to the analysis of the correlation between load and solar generation is that this study does not differentiate between a day and night correlation parameter.

Table 11 and Table 12 summarize the normalized parameters used to calculate the uncertainty of net demand. These were derived from estimates in the literature and the APS dataset.

**Table 11. Normalized Standard Deviation of Uncertainty across Flexibility Intervals**

| | **15-min** | **1-h** | **6-h** | **36-h** |
|---|---|---|---|---|
| **Load** | 0.3% | 1.2% | 1.4% | 2.8% |
| **Wind** | 1.3% | 5.3% | 6.4% | 10.2% |
| **Solar** | 1% | 4% | 4.2% | 6.5% |

**Table 12. Correlation of Uncertainty across Flexibility Intervals**

| | **15-min** | **1-h** | **6-h** | **36-h** |
|---|---|---|---|---|
| **Load, Wind** | 0% | -1% | -1% | 2% |
| **Load, Solar** | 0% | -1% | -1% | -2% |
| **Wind, Solar** | 0% | 2% | 2% | -1% |

## Appendix B. Flexibility Supply Parameters

This appendix identifies the flexibility supply parameters used in the base case. Flexibility supply parameters are identical between the DSW and the PNW, except for the typical dispatch during constrained periods. The parameters for thermal generation are summarized in Table 13. Typical dispatch parameters are reported in Figure 5 and are not repeated here. Similarly, typical dispatch for hydro (Figure 5), ramp rates for hydro (Table 5), and ramp rates for transmission (Table 6) are all reported earlier. DR parameters are summarized in Table 14.

**Table 13. Thermal Generator Flexibility Supply Parameters**

| Thermal Resource | Minimum generation (% capacity) | Ramp rate (% capacity/h) | Startup/shutdown time (h) |
|---|---|---|---|
| Coal | 40% | 60% | 48 |
| Steam | 10% | 100% | 8 |
| CCGT | 55% | 50% | 4 |
| CT | 45% | 300% | 1 |
| ICE | 25% | 330% | 1 |
| Cogen | 40% | 60% | 48 |
| Geothermal | 50% | 90% | 6 |
| Nuclear | 100% | 0% | 168 |

**Table 14. Demand Response Parameters**

| Demand response type | Notification | Directionality |
|---|---|---|
| Direct load control | None (with full deployment within 10 min) | Load curtailment (flexibility up) |
| Interruptible | 30 min | Load curtailment (flexibility up) |
| Other DR | 24 h | Load curtailment (flexibility up) |