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Resource Adequacy Requirements:
Reliability and Economic Implications

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EXECUTIVE SUMMARY

This report, prepared for the Federal Energy Regulatory Commission (FERC), assesses the economic and reliability implications of different resource adequacy standards. We examine the widely-used one-day-in-ten-years (1-in-10) loss of load standard, compare it to alternative approaches to defining resource adequacy, and evaluate the implications of different resource adequacy standards from a customer cost, societal cost, risk mitigation, market structure, and market design perspective.

The 1-in-10 Resource Adequacy Standard

Utilities, system operators, and regulators across North America have relied on variations of the 1-in-10 standard for many decades, and typically enforce the standard without evaluating its economic implications. In most U.S. power systems, this standard is interpreted to mean that planning reserve margins need to be high enough that involuntary load shedding due to inadequate supply would occur only once in ten years. *One event* in ten years translates to 0.1 loss of load events (LOLE) per year, regardless of the magnitude or duration of the anticipated individual involuntary load shed events. Alternatively, *one day* in ten years translates to 2.4 loss of load hours (LOLH) per year, regardless of the magnitude or number of such outages. As we show, the difference between these interpretations of the 1-in-10 standard translates to differences in planning reserve margins that may exceed five percentage points, with planning reserve margins of possibly less than 10% based on the 2.4 LOLH standard and more than 15% based on the 0.1 LOLE standard.

We survey the resource adequacy standards used in North American power markets. This survey shows that most North American systems set planning reserve margins using some variation of the 1-in-10 standard, although some set planning reserve margins based on economic considerations. Of the regions relying on the 1-in-10 standard, the majority interpret it as 0.1 LOLE. However, despite attempts to create a more uniform approach to interpreting and estimating LOLE, large differences remain in how the standard is interpreted across systems. In calculating LOLE, some systems define a reliability event as the involuntary curtailment of firm load. Other systems also consider other, less severe reliability events as contributing to LOLE, including voltage reductions or operating reserve depletions. We show that changing event definitions alone can translate to a four percentage point range in planning reserve margins. Due to these differences and its other limitations, the 0.1 LOLE standard does not represent a uniform level of reliability but instead can represent very different expected customer outage levels.

Additional differences exist in how planning reserve margins are calculated. For example, some system operators calculate reserve margins using the nameplate capacity of intermittent generation such as wind and solar, while others use a derated capacity value. Other differences exist in how voltage reductions or demand response are considered in reserve margin calculations. As we show, this means that *reported* planning reserve margins can differ by five percentage points based solely on supply and demand accounting conventions. Overall, these differences make it very challenging to meaningfully compare reported reserve margins across regions.

Simulating the Reliability and Economic Implications of Planning Reserve Margins

To examine the economic implications of the 1-in-10 resource adequacy standard, we conduct a series of reliability simulations using the Strategic Energy and Risk Valuation Model (SERVM) developed by Astrape Consulting. We simulate a hypothetical Study Regional Transmission Organization (RTO) system with a peak load of 50,000 MW that is interconnected through 11,000 MW of transmission interties to three neighboring regions with a combined peak load of 130,000 MW and planning reserve margins of 15%. The hypothetical Study RTO and neighboring regions do not exactly reflect any particular real-world system, but have realistic characteristics based on actual systems' hourly load shapes, load diversity, resource mix, generation performance statistics, weather conditions, demand response penetrations, and other characteristics derived from actual U.S. power system data.

We probabilistically evaluate resource adequacy conditions by simulating hourly generation availability, load profiles, load uncertainty, transmission availability, and other factors to estimate standard reliability metrics including LOLE and LOLH, as well as the economic implications of different planning reserve margins. We use 9,600 annual simulations for each case and Study RTO planning reserve margin level to evaluate: (1) reliability outcomes considering hourly generation and transmission intertie outages, uncertainties in weather, hydro, wind, and solar conditions, and economic load growth uncertainty; and (2) economic outcomes including hourly and annual production costs, customer costs, market prices, net import costs, load shed costs, and generator energy margins.

Through these probabilistic multi-area simulations, we evaluate the physical reliability, economic, and risk mitigation implications of different planning reserve margins under varying study assumptions related to: RTO size, intertie size, renewable penetration, emergency and demand response (DR) penetration, the cost of new generating plants, multi-year forward planning periods and the size of load forecast error, varying energy market price caps, and energy-only or capacity market designs. We did not evaluate some factors such as fuel availability or common mode failures of generators, pipelines, and transmission components. While SERVM is capable of modeling the economic and reliability impacts of each of these drivers, the scope of this study is limited to variables most commonly analyzed in other reliability studies.

Planning Reserve Margin Results Based on Economics and Physical Reliability

In our Base Case simulation, the Study RTO requires a planning reserve margin of 15.2% to meet the 0.1 LOLE resource adequacy standard, or a planning reserve margin of 8.2% to meet the 2.4 LOLH standard. Figure ES-1 summarizes the economic implications of the planning reserve margin, showing the tradeoff between reliability event costs (that decrease with higher planning reserve margins) and system capital costs (that increase with planning reserve margins). A planning reserve margin of 10.3% yields the lowest total annual system cost from a risk-neutral, cost-of-service perspective. From a societal cost perspective, the risk-neutral economically-optimal planning reserve margin would be only 7.9% above the Study RTO's non-coincident peak load, if each Neighbor continues to maintain a 15% reserve margin above their own non-coincident peak load. A 7.9% Study RTO reserve margin combined with 15% Neighbor reserve margins is equivalent to an overall four-system reserve margin of: (a) 13.0% if measured against the sum of the RTOs' non-coincident peak loads, and (b) 16.5% if measured against the coincident peak load of the combined system.[1]

Figure ES-1 also shows that the total average annual cost curve is relatively flat near the minimum cost point, indicating that expected total costs do not vary substantially between reserve margins of 8% and 14%. However, the lower end of that reserve margin range is associated with substantially more uncertainty in realized annual reliability costs and a much larger number of severe, high-cost reliability events.

Figure ES-1
Study RTO Reliability Costs as a Function of Study RTO Reserve Margin
(Risk-Neutral, Cost-of-Service Perspective)

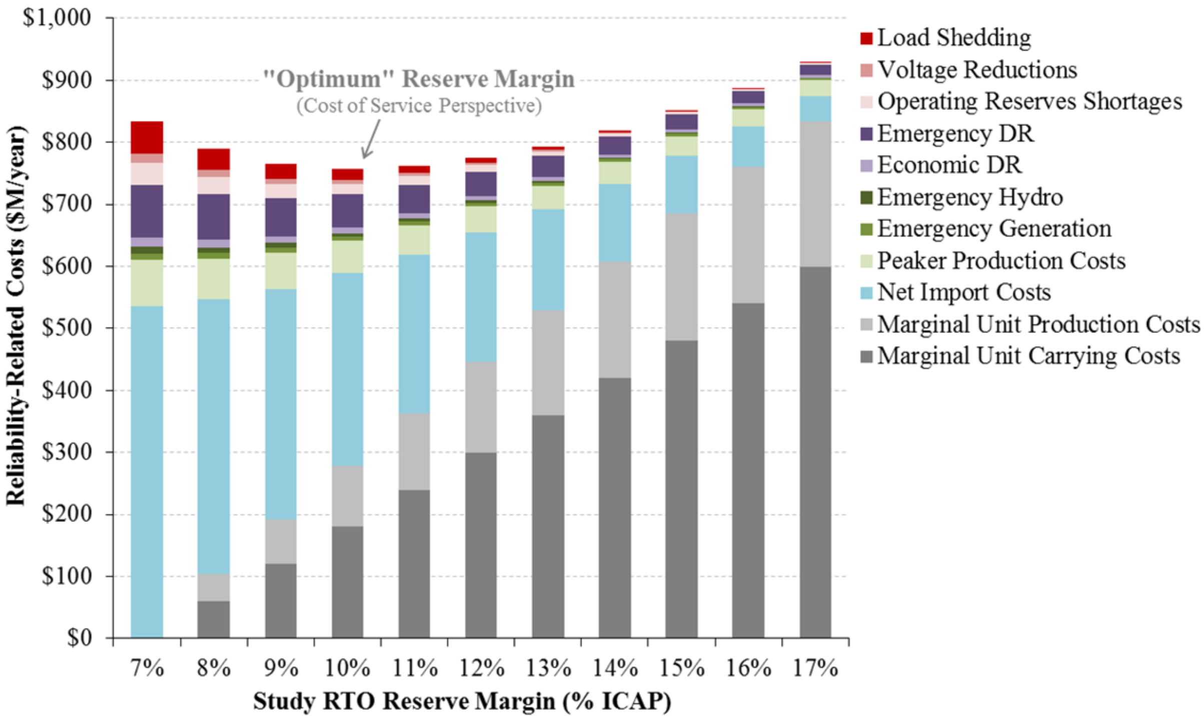


Table ES-1 summarizes the reliability-based and economically-based reserve margin targets for the Base Case simulation and for each of the alternative simulation cases we examined. These results show that varying assumptions regarding system size, topology, price cap, and other factors can substantially impact planning reserve margin targets. For example, the 0.1 LOLE reliability standard could require a reserve margin anywhere from 13.0% to 18.5% depending on the assumed system size, intertie level, and other characteristics. Similarly, economically-optimal reserve margins could vary anywhere from less than 6% to 16.5% from either a cost-of-service or societal perspective. The most significant factor impacting a region's planning reserve margin is the size of transmission interties, which resulted in Study RTO planning reserve margins ranging from 15.2% to 18.5% to maintain 0.1 LOLE or from 7.9% to 16.5% in terms of

[1] See Table 7 in Section III.A.3 for a more detailed explanation of this coincident vs. non-coincident reserve margin accounting convention.

economically-optimal reserve margins. Despite these differences, system characteristics have similar directional impacts on reserve margin targets for all resource adequacy criteria, both in terms of physical reliability and economics.

In addition to the simulation cases summarized in Table ES-1, we also analyze the implications of different levels of "emergency" and "economic" DR and different levels of intermittent renewable generation. With respect to dispatch-limited emergency demand response, we find that as emergency DR penetration increases, total costs initially decrease because these resources have lower capital costs than the conventional generation resources they replace. Even though emergency DR resources have a much higher dispatch cost than the displaced generating plants, the number of dispatch hours is low enough that it is advantageous to continue adding more DR initially. At higher penetration levels, however, limits on annual dispatch hours create a constraint after which it is no longer cost-effective to add emergency DR. Increasing the penetration of economic DR resources with unlimited call hours is more valuable in reducing system costs, with economically-optimal penetrations ranging from 8% to 14% depending on the fixed and variable costs of the assumed DR resources.

Table ES-1
Reliability-Based and Economically-Based Planning Reserve Margin Targets

Simulation	Reliability-Based			Risk-Neutral, Cost-Minimizing	
	0.1 LOLE	2.4 LOLH	0.001% Normalized EUE	Cost-of-Service Perspective	Societal Perspective
Base Case	15.2%	8.2%	9.6%	10.3%	7.9%
Lower Price Caps					
$1,000 Price Cap Case	15.2%	8.2%	9.6%	8.7%	7.9%
$3,000 Price Cap Case	15.2%	8.2%	9.6%	9.5%	7.9%
Smaller System Size					
40% Size Case	14.8%	<6%	7.5%	<6%	<6%
40% Size and Transmission	15.1%	6.9%	8.1%	<6%	<6%
Neighbor Assistance					
Long Neighbors Case	13.0%	<6%	7.0%	8.0%	<6%
50% Transmission Case	15.8%	9.8%	10.0%	12.3%	10.5%
Island Case	18.5%	16.5%	15.8%	16.5%	16.5%
Marginal CC Case	15.3%	8.3%	9.8%	10.1%	7.7%

Note:
Normalized Expected Unserved Energy (EUE) represents the percent of total energy not delivered (see Seciton I.B.1).

Market Design Implications

We also evaluate the implications of our simulation results within restructured wholesale power markets in which investments can only be attracted if prices are high enough on average for suppliers to earn the necessary return on their investments. Within energy-only markets, which do not rely on mandated planning reserve margins, investments must be attracted by net revenues earned from the energy market alone. Because supplier energy margins decline with increasing reserve margins, energy-only markets achieve an equilibrium reserve margin where net revenues are equal to investment costs. Our simulations show that energy-only markets can attract the optimal level of generation investments from a societal-cost perspective. However, we also demonstrate that if energy prices are suppressed below true marginal system costs during load shedding or other scarcity events, an energy-only market design will not be able to maintain an optimal level of investments. This highlights the importance of efficient price formation during scarcity events through well-designed scarcity pricing mechanisms that reflect the marginal system costs of emergency interventions and deploying demand-side resources.

Because the reserve margin in an energy-only market is the result of economic incentives, there is no guarantee that such a market will achieve any particular reserve margin or reliability level. Energy-only markets can suffer from a "missing money problem" with insufficient economic incentives to invest in new resources. This missing money problem may result from two different types of challenges: (1) missing money arising from energy prices that are artificially suppressed, for example, by low price caps or inefficiently low market prices during scarcity conditions; and (2) missing money relative to what is needed to achieve the reserve margin that policy makers desire, which may be higher than what an economically efficient energy-only market would support.

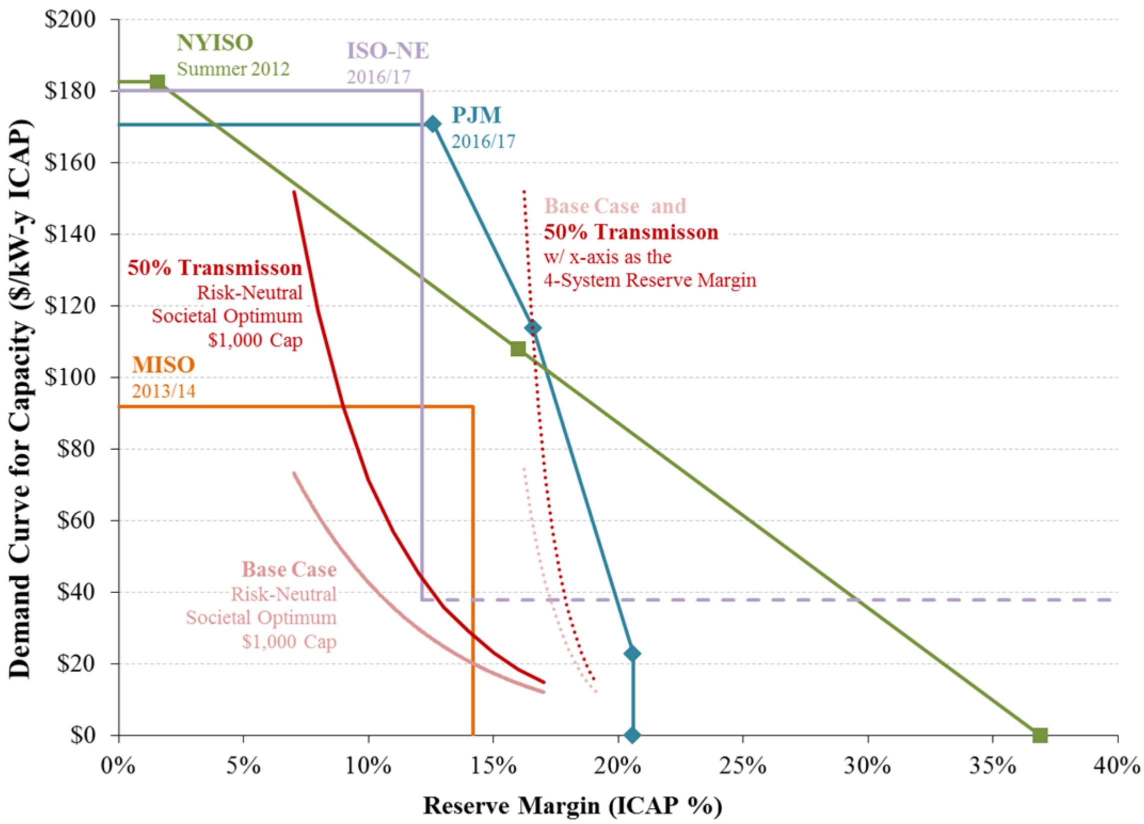
Resource adequacy requirements can be imposed to address the missing money problem and attain desired planning reserve margin targets. Imposing such a requirement will make capacity a valuable product in addition to the energy and ancillary services that are compensated in an energy-only market. Maintaining a higher reserve margin requirement will yield higher capacity prices to compensate for declining energy margins. If energy and ancillary service market prices are suppressed by price caps or other factors, this will also translate into higher capacity prices. To date, capacity markets have been designed to achieve planning reserve margins based on physical reliability standards rather than economic objectives such as minimizing system costs.

Our simulations demonstrate that a capacity market could be designed to achieve economically-optimal reserve margins through either: (a) imposing economically-based rather than physical reliability-based planning reserve margin requirements; or (b) implementing a demand curve for capacity that is designed to procure the cost-minimizing quantity of capacity. We show how such a cost-minimizing demand curve could be determined and compare the result to current RTO capacity demand curves as illustrated in Figure ES-2. The two red curves shown in the figures represent economically-optimal demand curves from a risk-neutral, societal perspective, assuming neighboring regions will maintain a 15% planning reserve margin. The risk-neutral cost-minimizing demand curves are plotted against: (1) the Study-RTO-internal reserve margin above Study-RTO non-coincident peak load (solid lines), as well as (2) the combined four-system reserve margin above the combined systems' coincident peak load (dotted lines).

We also examine the energy and capacity market outcomes at increased levels of DR penetration, assuming that DR will displace traditional generation. We show that increasing DR levels will result in increasing average energy prices, increasing energy price volatility, but decreasing capacity prices. Generally, economic DR that participates in the energy market has more favorable impacts on the market than dispatch-limited emergency DR. Currently, most DR assets have little incentive to participate in energy markets because energy market prices remain below their curtailment costs except under rare circumstances. However, at higher price caps and higher DR penetration levels, we anticipate that more DR resources will migrate from emergency to economic programs.

Overall, we find that the choice of an energy-only or energy-plus-capacity market design does not by itself have great implications for average supplier net revenues or average customer cost. Because supplier's net revenues must on average be sufficient to recover investment costs in equilibrium, changing market design or reserve margins does not change the annual average of anticipated net revenues. Rather, it only changes the proportion of revenues that on average would be earned from the energy market versus the capacity market. For customers, average annual costs do increase as reserve margins rise above the risk-neutral cost-minimizing level, but this impact represents only a very small portion of customers' bills. In fact, increasing the planning reserve margin from the risk-neutral, societal optimum of 7.9% to the 15.2% reserve margin needed to maintain 0.1 LOLE increases average annual customer costs by only 1.5%, but substantially reduces the variance of annual cost outcomes, including the potentially very high costs of extreme events. Other features of the regional power market, such as the amount of intertie capacity to neighboring regions, have a much larger impact on total customer costs.

Figure ES-2
Cost-Minimizing Capacity Demand Curve vs. Current RTO Demand Curves



Notes:

All curves converted from source units into ICAP terms for both reserve margin and price.

Cost-minimizing demand curves plotted with x-axis as: (1) the Study RTO reserve margin against Study-RTO non-coincident peak load (solid lines); and (2) against the combined four-system reserve margin against the combined coincident peak load (dotted lines). See Table 7 in Section III.A.3 for a more detailed explanation of this coincident vs. non-coincident reserve margin accounting.

I. INTRODUCTION AND BACKGROUND

The Brattle Group and *Astrape Consulting* have been asked by the Federal Energy Regulatory Commission (FERC) to assess the economic implications of resource adequacy standards. In particular, we examine the widely-used one-day-in-ten-years (1-in-10) loss of load standard and compare it to alternative approaches to defining resource adequacy. In this Section we: (1) describe study scope and approach; (2) explain how 1-in-10 and alternative resource adequacy standards are determined; and (3) provide a summary that compares how various standards are implemented in practice.

A. STUDY PURPOSE AND APPROACH

The 1-in-10 loss of load event (LOLE) standard requires that an electric system maintain sufficient generation and demand response resources such that system peak load is likely to exceed available supply only once in any ten-year period. Utilities, system operators, and regulators across North America have relied on variations of the 1-in-10 standard for many decades, and typically enforce the standard without an evaluation of its economic implications.[2] However, because the economic implications of different resource adequacy levels can be quite large, we and other industry observers have highlighted the need to examine the 1-in-10 standard from an economic perspective. To the extent that the economic value of resource adequacy standards is discussed in the industry today, there is no uniform approach to measuring the value of resource adequacy, such as the ability of incremental resources to reduce the frequency of customer outages and other emergency events, moderate energy price spikes, and increase wholesale competition. This lack of clarity makes it difficult for policymakers and industry participants to evaluate fundamental questions such as: (a) whether 1-in-10 criterion is still the right standard; (b) how higher planning reserve margins benefit customers; and (c) at what price capacity should be compensated.[3]

With this study, we seek to contribute to the understanding of these questions by developing a framework for assessing the economic value of resource adequacy and examining the implications of the 1-in-10 standard. We provide a brief summary of resource adequacy concepts in Section I.B, followed by a survey of how 1-in-10 and alternative resource adequacy standards are defined and implemented across North America in Section I.C.

In the remainder of the report we evaluate the economics of resource adequacy for a hypothetical interconnected power system that resembles existing regional transmission organization (RTO) and independent system operator (ISO) footprints. We use probabilistic simulation modeling to examine how reliability metrics, customer costs, and system costs vary with reserve margin. We also test the sensitivity of our results to input assumptions and underlying system conditions and compare the economics of the 1-in-10 standard to alternative reliability-based standards and standards based on economic objectives such as cost reduction and risk mitigation. We describe

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2 Exceptions exist, particularly in the Southeastern U.S., where the utility and regulators explicitly consider the economic implications of planning reserve margins when setting the reserve margin target as summarized in Section I.C.1.

3 For example, see Wilson (2010a-b).

our simulation approach and assumptions in Section II, report economic and reliability results in Section III, and summarize the implications for wholesale electricity market design in Section IV.

B. Approaches to Setting Resource Adequacy Standards

Resource adequacy can be assessed either in terms of physical reliability criteria or economic objectives. This section of our report defines the range of physical reliability criteria used in setting resource adequacy standards and explains how these standards are translated into target planning reserve margins. We then describe economic approaches to determining target planning reserve margins.

1. Interpreting 1-in-10 and Other Reliability Criteria

Although the 1-in-10 standard is widely used across North America, substantial variations in how it is implemented mean that it does not represent a uniform level of reliability. As recognized in recent work by the North American Electric Reliability Corporation (NERC) and Reliability*First* Corporation (RFC), the 1-in-10 standard may be interpreted as either *one event* in ten years or *one day* in ten years. *One event* in ten years translates to 0.1 loss of load events (LOLE) per year, regardless of the magnitude or duration of the anticipated individual involuntary load shed events. *One day* in ten years translates to 2.4 loss of load hours (LOLH) per year, regardless of the magnitude or number of such outages.[4] These two interpretations can represent very different levels of physical reliability, although there is no direct translation between them unless one assumes a typical outage duration. For example, if one assumes a 4-hour outage, then the events-based definition represents a reliability standard with outage durations that are one-sixth the outage duration achieved by the LOLH-based definition.[5]

The 1-in-10 standard can also represent different levels of reliability for different systems. This is the case because neither the LOLE nor the LOLH metric considers the MW size of the outage endured. For example, a one-hour, 100 MWh outage event and a one-hour, 10,000 MWh outage event would be counted identically under the LOLE and LOLH metrics, even though the load shed amount under the second outage event is one hundred times greater in magnitude. Further, the 1-in-10 standard represents a higher level of reliability in a large system than in a small system because neither the LOLE nor the LOLH metric is normalized to system size.[6] This means that a 100 MWh, one-hour outage will have the same LOLE and LOLH values in a 10,000 MW and 100,000 MW power system, even though individual customers in the smaller system are ten times more likely to endure an outage. We further illustrate the differences among these various interpretations in Section I.C for actual power systems and in Section III for a hypothetical system with realistic assumed characteristics.

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4 We also clarify that while we use these definitions of LOLE and LOLH throughout this report, others may use somewhat different definitions as we explain further in Section I.C.

5 In other words, 0.1 LOLE times a 4-hour outage results in 0.4 LOLH per year, or only one sixth of the 2.4 LOLH assumed in the hours-based interpretation. However, the comparison depends entirely upon the assumed outage duration.

6 This is true as long as the one event represents a smaller proportion of total load in a large system than in a small system.

Recognizing these limitations of the 1-in-10 standard, a recent NERC task force recommended using Normalized Expected Unserved Energy (EUE) as a new physical reliability metric.[7] Normalized EUE is the total expected firm load shed due to supply shortages, divided by the total system net energy for load, and therefore represents an overall percentage of system load that cannot be served. We agree with that report's conclusion that Normalized EUE is the most meaningful reliability metric that can be compared across systems of many sizes, load shapes, and other uncertainty factors. In fact, Normalized EUE is already used in some international markets to set minimum reliability thresholds or trigger administrative interventions, although the metric may be referred to as Loss of Load Probability (LOLP) or Unserved Energy (USE). Examples of metrics equivalent to Normalized EUE that are used in international markets include: (a) a 0.001% LOLP standard in Scandinavia; and (b) a 0.002% USE standard in Australia's National Energy Market (NEM) and South West Interconnected System (SWIS).[8]

Unfortunately, these and similar terms such as the Probability of Lost Load (POLL) are also not used and defined uniformly. For our purposes and for the remainder of this report we will refer only to: (1) LOLE measured in events per year; (2) LOLH measured in hours per year; and (3) Normalized EUE measured in percent of system-wide load unserved. While there is not a direct translation among these three physical reliability metrics (unless one assumes an average outage size and duration), they can be estimated and compared for an individual system that has a particular distribution of expected load and other uncertainty factors. Section III presents such comparisons.

Also note that, historically, the 1-in-10 standard as applied by system operators in North America translates to expected annual outages for end-use customers that average less than a few minutes per year on a system-wide basis. This compares to total customer outages averaging several hundred minutes per year on a system-wide basis, most of which are caused by distribution system outages.[9] Nevertheless, despite the fact resource adequacy-related reliability events account for only a very small fraction customer outages, such "rolling blackouts" attract disproportionate media and political attention whenever they happen.[10]

2. Determining System Reliability as a Function of Planning Reserve Margin

The 1-in-10 resource adequacy standard is not a readily observable metric. For example, one cannot simply review a region's integrated resource plan (IRP) or reserve margin outlook to determine whether the 1-in10 standard will be achieved. This is because such supply-related

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7 See the NERC (2010).

8 See Nordel (2009), p. 5; AEMC (2007), pp. 29-30, (2010), p. viii.

9 See Newell, *et al.* (2012), pp. 101-2.

10 For example, during the summer of 2012, the Alberta Electric System Operator (AESO) instituted load shedding due to heatwave-related peak loads and unexpected generation outages. This required rolling 30-minute curtailments of 200 MW of firm system load over a two-hour period. Despite attracting substantial media and political attention (see, for example, Sellin (2012) and Henton (2012)), this 200 MW curtailment affected only approximately 2% of almost 10,000 MW of total system load, which means an average customer outage duration of only approximately 2.4 minutes (2% of 120 minutes) on a system-wide basis. Only 3 such events occurred in Alberta in the last decade, one on July 2, 2013 (but triggered by a transformer outage, not resource adequacy constraints).

reliability outcomes depend on a host of complex factors such as anticipated resource mix and weather uncertainty. For this reason, most system operators use reliability modeling to translate the 1-in-10 standard into a planning reserve margin.[11] Such reliability modeling is used regularly even in markets without explicit resource adequacy requirements, including Texas, Alberta, Australia's NEM, and Scandinavia, to monitor reliability levels and determine whether administrative interventions are warranted to maintain adequate system resources.[12]

For markets with explicit planning reserve margin requirements, the requirement is typically calculated based on probabilistic reliability modeling that simulates LOLE as a function of the level of installed generating capacity. Such a simulation exercise requires statistically characterizing the uncertainty in forecasted load, the reliability of the generation fleet including intermittent resources, the likely availability of imports, and a number of other factors as explained further in Section II. The simulations are used to estimate reliability levels over a range of reserve margins, showing that the number or duration of expected load shed events decreases as capacity is added and the planning reserve margin increases.

Figure 1 illustrates how LOLE may decrease with reserve margin, showing an example where a planning reserve margin of 15% would be needed to achieve the 0.1 LOLE standard. We implement this type of reliability modeling for a realistic but hypothetical RTO in this study, as discussed in Sections II through IV.

To understand the economic value of different resource adequacy levels, one must also estimate the value of reliability to customers. One component of this reliability value is the ability to avoid costly load shedding events, the value of which can be estimated by: (1) determining the approximate value of lost load (VOLL), which is the cost of an outage to customers or the price that an average customer would be willing to pay to avoid an involuntary interruption of their electricity supply; and (2) multiplying VOLL by the amount of load shed. This estimate of the

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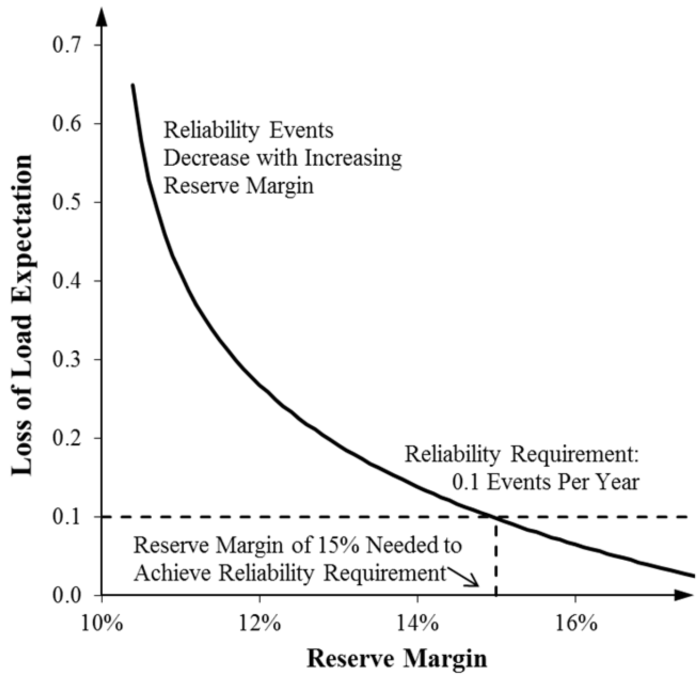
[11] In addition to planning reserve margins based on installed generating capacity and anticipated (50/50) peak load during normal weather conditions, power markets also require various types of "operating reserves" such as regulating reserves, spinning reserves, non-spinning reserves, and replacement reserves. Operating reserves are needed to balance load and supply reliably on a moment-by-moment basis and enable the system operator to quickly and reliably react to contingency events. In contrast to operating reserve requirements, which apply during real-time system operations irrespective of load levels or plant availability, planning reserve margins are meant to ensure that sufficient supply is available to address reliability challenges due to differences between: (1) near-term or medium-term peak load forecasts (which reflect average weather) and typical generation outages; and (2) actual peak loads (which can exceed reflected weather-related spikes in load) and spikes in generation outages. Because of the differences between forecast and actual peak loads, the year-to-year realized reserve margin will fluctuate considerably around the average. In this section, as well as throughout this report, we refer to "planning reserve margin," "target reserve margin," or simply "reserve margin" to refer to this forward-looking estimate of installed capacity (ICAP) relative to the forecast normalized peak load. We refer to "operating reserves requirements" or "operating reserves" when referring to the quantity of regulating and contingency reserves that are needed to maintain real-time grid stability in every hour.

[12] AESO developed its long-term adequacy (LTA) metrics to determine a forecast level of reliability at which point AESO may need to intervene in the market, see AESO (2008), Section 1. For additional discussion on similar regulatory methods in other countries, see Pfeifenberger, Spees, and Schumacher (2009), pp. 28-29.

economic cost of load shed events will be a decreasing function of the reserve margin with a shape similar to that in Figure 1.[13] However, as we discuss further below, the system-wide expected VOLL is only one component of total reliability-related system and customer costs that must be considered when evaluating the economic implications of different resource adequacy levels.

Figure 1
Reliability vs. Reserve Margin



Notes:
Illustrative figure does not represent any actual or simulated system.
Similar charts for real systems are available in various reliability studies, for example see Electric Reliability Council of Texas (ERCOT) results in ECCO (2013), pp. 8-9.

3. Determining Economically "Optimal" Reserve Margins

To understand economic tradeoffs over a range of planning reserve margins, one must also estimate the incremental value and costs associated with additional capacity resources. In this study we implement such economic reliability simulations to assess these tradeoffs, building upon previous studies conducted for regulated entities and in academia.[14] In particular, *Astrape Consulting* has conducted a number of such studies using the Strategic Energy Risk Valuation Model (SERVM) reliability simulation tool, which we also use to analyze the case studies

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13 See Wilson (2010a) and Centolella (2010).

14 For example, a 1992 study for Pacific Gas and Electric compared the traditional 1-in-10 standard against a value-of-service approach, showing that the traditional standard required a reserve margin of 22.5% while the value-of-service approach indicated an efficient reserve margin of 16.2%. See Keane, *et al.* (1992), pp. 824, 826. For similar analyses, see also Poland (1988), p.21; Munasinghe (1988), pp. 5-7, 12-13; and Carden, Pfeifenberger, and Wintermantel (2011).

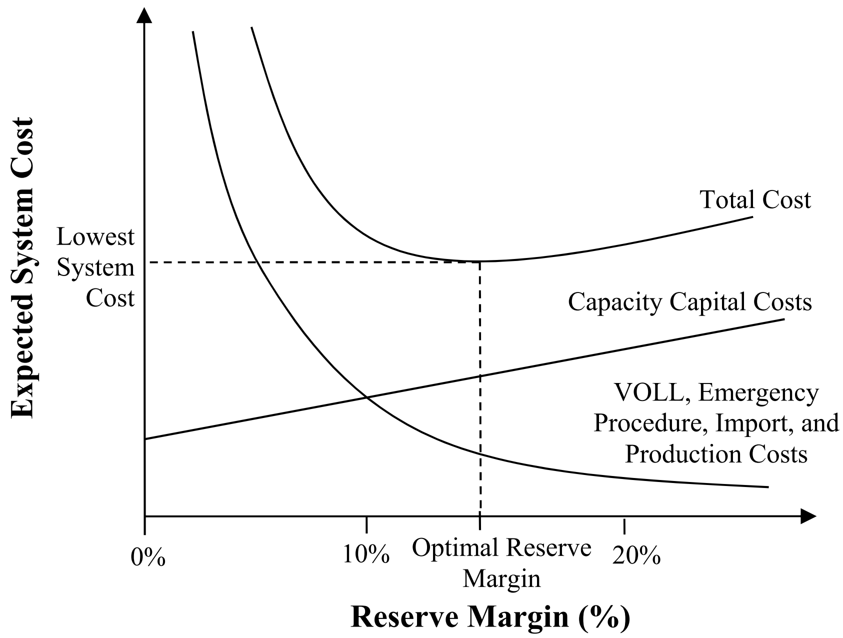
presented in this report. The objective of such an economic reliability study is to determine an "optimal" reserve margin that minimizes total system or customer costs, including the capital cost of adding resources, production costs, off-system and emergency purchase costs, and the cost of load shed events.

The objective of minimizing total system costs is demonstrated schematically in Figure 2. The figure shows that increasing the planning reserve margin will increase capital costs as more resources are added to the system. However, increasing the reserve margin also reduces outage costs by reducing the frequency, duration, and magnitude of load shed events, may reduce production costs by reducing the need to dispatch higher-cost peaking resources, and may reduce power purchase costs by reducing the need to call on higher-cost imports during reliability events.[15] The "optimal" reserve margin is that which minimizes expected system or customer costs by weighing the tradeoff between the incremental costs and the benefits of increasing the reserve margin.

However, this cost-minimizing reserve margin only represents the point at which costs are minimized on an expected value basis, and therefore represents the "optimum" reserve margin from a risk-neutral perspective. As we discuss further in Sections III.A.2–4 below, the point of the lowest system cost represents the probability-weighted average cost over many possible system conditions. This probability-weighted average cost is influenced greatly by low-probability, very-high-cost shortage events, such as an extreme heat wave that happens to coincide with substantial generation outages. Because customers and policy makers are risk averse, avoiding such high-impact events will be valuable. Customers and policy makers may therefore prefer to pay more to maintain a somewhat higher reserve margin that can mitigate the risks and impacts of extreme shortage events.

[15] The magnitude of avoided load shed costs will not typically depend on what type of capacity resource is added because many types of resources have similar likelihoods of being available for dispatch during load shed events. However, the magnitude of net reductions in production costs, avoided import costs, and increases in capital costs are highly dependent on the type of capacity added. For example, adding combustion turbines (CTs) will incur lower capital costs than adding combined cycles (CCs), but will also provide fewer benefits from avoided production and import costs. For this reason, the "optimal" reserve margin depends on the type of marginal technology assumed when varying the reserve margin as discussed further in Section III.B.3.

Figure 2
"Optimal" Reserve Margin at Lowest System Cost



Notes:
Illustrative figure does not represent any actual or simulated system.
See Sections III.A.2–4 for a more thorough discussion and estimate of the economic optimum within a hypothetical simulated system.

C. SURVEY OF RESOURCE ADEQUACY CRITERIA IN NORTH AMERICA

This section documents variations in how the 1-in-10 and alternative resource adequacy standards are used and interpreted in existing power markets across the U.S. and Canada. This discussion is based on our interpretation of RTO and utility planning and reserve margin studies as summarized in Appendix A. However, we caution that, to completely understand the nuances and complexities of these studies, one would need to discuss implementation details with the individuals responsible for conducting the studies. The public documentation of these studies is often insufficiently detailed or can easily be misinterpreted. Because we have not conducted such interviews to be able to document the assumptions and the complexities of each study, our discussion should be interpreted as a preliminary summary of general industry practices, not a fully-verified documentation of any one region's approach.

As we explain, most of these regions rely on a 1-in-10 reliability standard, but substantial variations in interpretation, conventions used in calculating reserve margins, modeling approaches, and underlying system conditions make it very difficult to meaningfully compare different systems' reliability levels and reported reserve margins.[16]

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[16] The markets we survey here include PJM Interconnection (PJM), New York ISO (NYISO), ISO New England (ISO-NE), California ISO (CAISO), Northwest Power Pool (NWPP), Florida Reliability Coordinating Council (FRCC), Electric Reliability Council of Texas (ERCOT), Southwest Power Pool

Continued on next page

1. Differing Resource Adequacy Standards

Appendix A.1 summarizes the resource adequacy criteria established by system operators and reliability coordinators across the U.S. and Canada. As shown, the majority, but not all, of these regions use the 1-in-10 resource adequacy standard. Most of these regions define 1-in-10 as 1 event in 10 years, or 0.1 LOLE per year. However, SPP differs in that it interprets 1-in-10 as 24 hours of curtailments in 10 years, or 2.4 LOLH per year.

Several reliability operators in the Southeast establish resource adequacy targets based on economic analysis with the objectives of minimizing customer costs and mitigating the risk of high-cost events. Other entities use alternative physical reliability criteria tailored to their own needs, such as the BC Hydro system that must also consider the potential for energy-constrained low-hydro conditions leading to overall energy limitations. Finally, Texas and Alberta both have reliability targets but do not impose these targets as mandatory standards for resource adequacy.

2. Differing Conventions for Calculating Reserve Margins

One important reason that it is difficult to compare the level of resource adequacy across systems is that each region adheres to a different set of conventions when calculating their reserve margins. In other words, even if two regions had identical peak load and expected resource mix, they may calculate different reserve margins using different conventions. In fact, even within a single market, there may be different approaches used when calculating reserve margins for the purposes of publishing summer or long-term resource adequacy assessments, conducting transmission planning exercises, conducting a reliability studies, or implementing a capacity market.

a. Accounting for Demand-Side Resources

All regions have some demand response (DR), load curtailment, retail price response, or other load-side resources that contribute to resource adequacy. Aside from the fact that it is sometimes difficult to estimate the total resource adequacy value of a particular type of DR program, there is also no standard approach regarding how these resources are included in the reserve margin calculation. Some entities include demand response as a reduction in load while other regions include it as a supply-side resource.

> *Example: DR counting as a supply-side resource versus a reduction in load changes calculated reserve margin (RM) by 5% from 20% to 25%.*
>
> *Assume:*
> *Load = 100,000 MW*
> *Gen = 100,000 MW*
> *DR = 20,000 MW*
>
> *Reserve margin if treating DR as supply resource:*

Continued from previous page

(SPP), and various SERC Reliability Corporation (SERC) and Western Electricity Coordinating Council (WECC) entities. We draw upon previous NERC surveys as well as individual entities' planning and reliability modeling documentation. For example, see NERC (2010a).

RM = (Gen + DR) / Load – 100%
20% = (100,000 + 20,000) / 100,000 – 100%

Reserve margin if treating DR as a reduction in peak load:
RM = Gen / (Load – DR) – 100%
25% = (100,000) / (100,000 – 20,000) – 100%

Further, there are different conventions used for adjusting nominal DR capability by: (a) derating that capability by an expected availability rate; or (b) if treating DR on the supply side, possibly grossing up the nominal capacity value for avoided line losses and reserve margin requirements. These differences in DR accounting change the numeric value of the planning reserve margin, but not the system's underlying resource adequacy situation.

b. Accounting for Emergency Operations

Similarly, while all regions implement various types of emergency procedures before shedding load, there is no standard approach as to how these procedures are accounted for when calculating reserve margins. For example, PJM will implement voltage reductions and may achieve approximately 2.5% reduction in peak load before firm load shedding is required. In the Southern Company (SoCo) region, approximately 2% of peak load is available from voltage reduction and other emergency procedures.[17]

However, the regions differ in terms of how these procedures are accounted for in their reserve margins, with PJM not considering the capacity benefit of emergency procedures and SoCo treating emergency procedures as supply resources. Overall, as summarized in Table 1, the convention of whether to count emergency procedures as a supply resource, load reduction, or neither would result in calculated reserve margins ranging from 15.6% to 18.6% in PJM and from 13.0% to 15.3% in SoCo.

Table 1
Emergency Procedure Accounting Impact on PJM and SoCo Reserve Margins

	Load Reduction from Emergency Procedures	**ICAP Reserve Margin**			
		As Reported	Emergency Procedures Counted as Supply Resources	Emergency Procedures Counted as Load Reduction	Emergency Procedures Not Counted
	(%)	*(%)*	*(%)*	*(%)*	*(%)*
PJM	2.5%	15.6%	18.1%	18.6%	15.6%
SoCo	2.0%	15.0%	15.0%	15.3%	13.0%

Sources and Notes:
As-reported reserve margin requirements from PJM (2012c), and Georgia Power (2010).
Alternative reserve margin calculations assume no change other than how voltage reductions are included or not.

17 PJM voltage reduction value approximately calculated from PJM (2012a), p. 63.

c. *Derating Capacity from Different Resource Types*

When calculating the reserve margin, some planning regions include all resources at their nameplate capacities, while others include only a derated capacity value for intermittent or dispatch-limited resources, such as wind, solar, hydro, or storage. These derated capacity values are calculated using a variety of different approaches.[18] The decision of whether to derate certain resource types and, if so, how to calculate the derate magnitude, is partly a matter of convention and partly a reflection of the importance of various resource types in the overall resource adequacy picture in a particular region. For example, a region with few hydro resources may not place particular emphasis on developing a detailed assessment of those assets' reliability value; while a hydro-dominated region such as British Columbia must conduct detailed evaluations of its hydro resource base and probabilistic availability under a number of weather and hydrology scenarios.

To illustrate the importance of derate accounting conventions, we compare the conventions PJM and NYISO used in their reliability assessments. PJM adopted a 15.6% installed capacity (ICAP) planning reserve margin target in its most recent reliability study.[19] Under PJM's resource accounting methodology, demand response is derated to 95% of nameplate capacity, wind to 13%, and solar to 38% of nameplate capacity.[20] In comparison, NYISO calculates an ICAP reserve margin requirement of 16.1%, but uses the full nameplate capacity of all its resources in that calculation.[21] As explained in the NYISO study, this difference in accounting conventions has a substantial impact on the calculated ICAP reserve margin, particularly under very different levels of wind penetration.

Taking NYISO's resources and using PJM's derate methodology, NYISO's 16.1% ICAP reserve margin target would decrease to 10.7% as shown in Table 2 below. PJM's target reserve margin using the NYISO's resource accounting methodology would increase to 16.8% from 15.6%.

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18 For example, for wind, PJM uses a unit-specific availability calculation over a three-year history during summer peak hours, while the Midcontinent ISO (MISO) conducts a fleet-wide Effective Load Carrying Capability (ELCC) study each year. See PJM (2010), MISO (2012a).

19 Note that PJM conducts a new reliability study each year, and in each study may recommend a different reliability requirement for each delivery year. In this subsection we refer to the year 2012 reliability study as effective for the 2016/17 delivery year, see PJM (2012c).

20 To add an even further layer of complexity, the capacity market through which the reserve margin requirement is procured is conducted on an unforced capacity (UCAP) rather than ICAP basis as discussed further in the following subsection I.C.2.f. The deratings reported here apply to the calculation of the ICAP reserve margin. However, a different, additional adjustment is also applied to each resource type when calculating its UCAP value. For the purposes of calculating UCAP from ICAP, DR resources' capacity value is grossed up to account for avoided reserve margin needs, most generators' capacity value is reduced according to unit-specific outage rates, and wind and solar units' derated capacity value is the same on either an ICAP or UCAP basis. See PJM (2012c, 2010, 2013a).

21 For the 2012/13 delivery year, as estimated in the 2011 study. As in PJM, there is also a separate translation for determining the UCAP capacity value of each resource as would be used in the capacity market. See NYSRC (2011).

Table 2
Illustration of Differences in PJM and NYISO Target Reserve Margin Calculations

	Peak Load	Nameplate Capacity			Derated Value			ICAP Reserve Margin		
	Summer 2012	Wind	Solar	DR	Wind	Solar	DR	As Reported	Using Nameplate Capacity	Using Derated Capacity
	(MW)	*(MW)*	*(MW)*	*(MW)*	*(%)*	*(%)*	*(%)*	*(%)*	*(%)*	*(%)*
PJM	151,394	1,305	564	7,263	13%	38%	95%	15.6%	16.8%	15.6%
NYISO	33,335	1,648	39	2,192	11%	65%	85%	16.1%	16.1%	10.7%

Sources and Notes:
See PJM (2012c), NYSRC (2011).
We do not attempt to document the entirety of differences in reserve margin accounting, but only illustrate the impact of these specific derating conventions applied over this reported quantity of resources. A number of other factors related to how these resources are modeled will also influence the reserve margin calculation, which we do not attempt to discuss here.
NYISO DR value refers only to special case resources (SCRs), see NYSRC (2011), p. 51.

This shows that, while NYISO's reported ICAP reserve margin target exceeds that of PJM, it is lower than PJM's when calculated on a comparable basis. But note that, because the technical details of resource adequacy studies and the regions themselves can vary considerably, even if PJM's and NYISO's reserve margins were calculated consistently with respect to the treatment of the resources' nameplate capacity, a lower reported planning reserve margin would not necessarily mean lower reliability.

d. Uncommitted Resources, Planned Retirements, and Planned Additions

Another difficulty in comparing reserve margins across regions or even within a particular region is that one must determine whether and how to account for resources that may or may not be available in a future delivery period. In particular, there are different approaches to accounting for:

Uncommitted Resources that exist within the footprint and so are likely to provide resource adequacy value, but that do not have any firm commitment to be available through either a contractual agreement or a capacity market obligation. Without a firm commitment to provide internal capacity, these resources are free to retire or export their capacity and so may not be available when needed.[22]

Planned Retirements are sometimes known with substantial lead time and so can be properly accounted for. But in many cases plant owners do not have to report retirements to the system operator until shortly prior to the delivery period. This uncertainty is currently of substantial concern in MISO, where a large number of coal plants are at risk for retirement under the Mercury and Air Toxics Standard (MATS). However, the RTO has a limited

22 This is one reason that some RTOs including PJM separately report committed and uncommitted "reserve margins" when conducting summer resource assessments, see PJM (2013e).

forward view regarding the quantity and location of these retirements, which introduces substantial uncertainty for both transmission and resource planning.[23]

Planned Additions are similarly uncertain on a forward basis. The majority of announced generation projects are never brought into commercial operation, but may be partly developed before being postponed or cancelled depending on market and site conditions. For this reason one must carefully evaluate the commercial probability of various proposed resources when calculating a future reserve margin, for example, by assigning different probabilities that each resource will come online depending on how far along it is in the development process.[24]

Again, the conventions used to account for these resources change the reported reserve margins despite the fact that they do not change the underlying resource adequacy position. Unfortunately, attempting to standardize the treatment of these uncertainties may be counter-productive, since the most appropriate convention to use is highly dependent on the purpose for which the reserve margin is calculated. For example, a transmission planning study that looks five to twenty years into the future must include some reasonable assumptions about speculative additions and retirements, while a near-term summer assessment may most appropriately consider only committed resources that can definitely be relied upon.

The large range in different reserve margins that can be calculated using different conventions is illustrated each year in the annual NERC *Long Term Reliability Assessment* (LTRA) that documents the reserve margin outlook for all regions. To help with some standardization across regions, NERC provides guidance regarding how to account for uncertain resource types for a range of optimistic or pessimistic outlooks. This improves the ability to compare outlooks across regions, but does not solve the problem entirely due to differences in interpretation, even on a very near-term basis where uncertainty is lowest. For example, the 2012 LTRA outlook reports the summer 2013 anticipated reserve margins for 26 different regions, of which: (a) 12 reported no difference between the most pessimistic and optimistic reserve margin outlooks for the summer of 2013; (b) another 8 reported up to 1% uncertainty range; (c) another 3 reported up to 10% uncertainty range; and (d) another 3 reported higher uncertainty ranges of up to 18% difference between the most optimistic and pessimistic cases.[25] The ranges diverge even further when looking further into the future.

e. Accounting for Tie Benefits

Being interconnected to neighboring regions can improve resource adequacy in two ways. First, by enabling a region to procure *firm commitments* from external resources to supply and deliver power during emergency events. And second, by creating *tie benefits* that enable the region to request neighbor assistance, if available, through non-firm imports during emergency events. The latter type of assistance is neither guaranteed nor contractually obligated to materialize, but

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23 For example, see a discussion of these uncertainties and MISO's concerns about these uncertainties in MISO (2013b).

24 PJM uses this approach for a number of purposes, see PJM (2012c).

25 See NERC (2012), p. 68.

the likely availability of these tie benefits can be probabilistically evaluated as discussed in Section I.C.3.d below.

It is standard practice to include firm imports on the supply side of a reserve margin calculation, but there is no standard practice for how to include tie benefits. For example: (a) the most common approach, such as used in PJM and MISO, is to exclude tie benefits from the calculated reserve margin, which means the target reserve margin is lower than it would be if tie benefits were included as a resource; (b) some regions, such as ERCOT, treat all or part of their interties as a supply resource that increases the calculated reserve margin; (c) other regions, such as Alberta, sidestep the problem of evaluating the reliability value of the interties by simply reporting the reserve margin with the interties contributing at zero or 100% of their path rating; (d) some regions, such as SPP, do not account for tie benefits at all; and (e) yet other regions have special circumstances, such as ISO-NE's separate treatment of two portions of the tie benefits, one part that is specifically allocated to entities that own the rights to an intertie with Québec, and another part that is allocated equally to all loads.[26]

f. Accounting for Installed and Unforced Capacity

A final source of discrepancy is the differing conventions for expressing resource adequacy targets either in terms of: (1) "installed" capacity ratings that account for thermal generators at their maximum output capability; or (2) "unforced" capacity ratings that discount resources' capacity rating by an expected forced outage rate (EFORd). All regions use ICAP reserve margins for most reporting purposes, including summer and long-term resource assessments. However, even under ICAP accounting there are varying degrees of uncertainty. For example, it is relatively easy to find the same plant listed at different ICAP values since the RTO may be reporting a nameplate, summer, winter, emergency maximum, committed, or an annual capacity test value. It is not unusual for an individual thermal generation resource to have reported capacity values that vary by many percentage points.

The consequences of such accounting discrepancies can have high financial implications in regions with bilateral or centralized capacity markets, with individual suppliers' capacity payments potentially materially impacted by such differences. For this reason, MISO, PJM, and NYISO have all opted to conduct their capacity auctions on a UCAP basis, which more systematically accounts for individual resources' summer availability after accounting for unit-specific historical availability ratings.[27] Under UCAP accounting, all resource types are derated to their expected "unforced" availability during summer peak conditions so that resources have a more similar contribution to resource adequacy. While the approach to calculating UCAP is different for each resource type and also varies by region, the UCAP-based reliability requirement is more meaningful and comparable under different resource mixes and across regions. Despite the advantages of UCAP accounting, however, RTOs generally continue their

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[26] See PJM (2012c); MISO (2012c); ERCOT (2013b); SPP (2012b), p. 20; ISO-NE (2012); and AESO (2013).

[27] However, both California's Resource Adequacy Requirements and ISO-NE's Forward Capacity Market are implemented using ICAP accounting.

historical approach of reporting ICAP-based planning reserve margins for nearly all purposes other than capacity auctions.

3. Differing Approaches to Conducting Reliability Modeling

Even though most of the planning entities surveyed define the 1-in-10 standard as 0.1 LOLE, the resource adequacy levels of these regions nevertheless may not be comparable. Each system operator conducts its own LOLE study using a range of different modeling assumptions. As a consequence 0.1 LOLE does not represent the same level of reliability in each system. These differences result from using different reliability modeling tools and a wide range of different study assumptions.

In this section, we highlight a number of important factors that create these discrepancies. In Appendix A.2 we further illustrate the wide range of approaches by summarizing those used for ISO-NE, NYISO, PJM, MISO, SPP, and SoCo.[28] To fully understand reliability differences across different systems, all studies and reserve margin calculations would need to be undertaken using consistent assumptions, methodologies, and definitions. A recent initiative by NERC resulted in recommended modeling assumptions that attempt to reconcile at least some of these existing discrepancies.[29] We also note that this list of differences among modeling approaches represents only a small subset of all potential differences, and that we have not attempted to document other important factors such as hydro resource modeling, wind resource modeling, approaches to characterizing correlations among load, wind, hydro, and generator outages, or approaches to calculating sub-regional resource adequacy requirements.

a. Different Reliability Modeling Packages

Different system operators use different models to conduct their reliability studies, including GE-MARS, SERVM, ABB Gridview, Genesys, and other non-commercially available models such as PJM's Prism Model and Florida Reliability Coordinating Council's (FRCC's) TIGER Model.[30] The models differ considerably, including in the range of uncertainties considered and how these uncertainties are captured in simulations. These differences can translate to very different study results.

b. Definition of Reliability "Events"

Regions that use the 0.1 LOLE standard hope to achieve a resource adequacy level of only one "event" in ten years. However, as noted previously, there is no standard approach for determining what constitutes a reliability "event." Some LOLE studies and system operators define a reliability event as any event requiring emergency operating procedures, such as calling

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28 Tennessee Valley Authority (TVA), Duke, Progress Energy, Louisville Gas and Electric Company (LG&E), and Kentucky Utilities Company (KU) use assumptions similar (though not identical) to SoCo. For example, TVA does not include DR as a resource. Duke, Progress, LG&E, KU, and TVA define a reliability event as an event that requires the depletion of spinning reserves, whereas SoCo defines a reliability event as an event that requires depletion of any type of operating reserve.

29 NERC (2010b).

30 See Appendix A.1 for a summary of the reliability modeling packages used in various systems.

demand response, implementing voltage control, or depleting operating reserves. In other systems, the studies consider reliability events as contributing to the tabulated LOLE only if operating reserves are depleted *and* firm load must be shed. Finally, many reliability studies do not explicitly account for the nature, order, and impact of various emergency intervention events. These factors can have a substantial impact on study results as illustrated in Section III.A.1 below.

c. Treatment of Load Uncertainty

One of the most important factors driving resource adequacy is uncertainty in peak load, which is driven by both weather uncertainty and economic forecast uncertainty.[31] For example, the combination of the number of weather years studied, the process used to derive peak and hourly loads under normal weather conditions, and the probabilities assigned to extreme weather patterns can change planning reserve margin targets by several percentage points. For example, a recent LOLE study by ERCOT found differences in weighting the 2011 weather year, which some refer to as a 1-in-100 year heat wave. Depending on how likely such extreme weather is to recur, the resulting target reserve margins would range from a low of 13.7% (with zero probability) to a high of 18.9% (with a 5% probability).[32] Even differences in how the projected load growth is applied to a base-year profile yielded target reserve margins ranging from 15.3% to 16.1%.[33] As another example, some regions such as PJM consider uncertainty due to economic load forecast error over the planning horizon when calculating the reserve margin needed to meet 0.1 LOLE, while other regions such as ISO-NE exclude this portion of load forecast uncertainty and instead consider only weather-related load uncertainty.[34]

d. Estimating Tie Benefits

As explained in subsection I.C.2.e above, regions differ in how they account for tie benefits in their reserve margin calculations. In this subsection, we further explain how regions differ in their approaches to estimating tie benefits. Some studies assume a maximum import capability or tie benefit, simply counting that quantity as a firm resource. Other studies explicitly model surrounding regions' load and resources to probabilistically estimate the availability of imports during reliability events. Among the regions that do probabilistically assess tie benefits, differences in modeling approaches include assumptions regarding:

- ***Maximum Intertie Ratings*** – Determining the total quantity of intertie capability to use in resource adequacy studies is not as simple as calculating the line ratings for every import point in a region. Instead, this is a complex engineering estimate that must consider simultaneous import capability from multiple directions under the expected peak season power flows. Further, the maximum intertie portion used for the purposes of calculating non-firm tie benefits is the total path rating minus any portion of the interties already used to support firm import commitments as discussed further in Section III.B.2 below. Most

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31 As discussed further in Sections II.D and III.A.5 below.

32 ERCOT (2013a), pp. 24-26.

33 ERCOT (2013b), Section 2.2.3 (p. 4) and pp. 7-8.

34 See PJM (2012c) and ISO-NE (2012).

systems use simplified assumptions about maximum intertie ratings that may not be updated regularly to reflect changing system conditions.[35]

Probabilistically Available Intertie Capability – Many reliability studies assume a fixed path rating and assume that the transmission will be entirely available at all times. However, this is not strictly true since every path may have variable availability, for example due to simultaneity, line outages, or temperature deratings. Some studies probabilistically account for these uncertainties in path ratings, as we do in the hypothetical RTO simulations presented in this report.[36]

Load Diversity – One of the important drivers of tie benefits is the extent of load diversity across regions. For example, if one region experiences a peak load emergency while the neighboring region does not, then assistance should be available over the interties. However, the scale and variability of load diversity can be characterized in many different ways. For example, NYISO's planning models simulate neighboring regions, but assume that all neighboring regions have the same highest peak-load hours, all based on a single historical year. As explained in their study, this is a conservative assumption that reduces the amount of capacity that would be available from neighboring regions during NYISO reliability events.[37] In contrast, PJM's planning study assumes different levels of peak load diversity with each of its neighbors, meaning that PJM assumes other regions' peak loads are a certain percentage below their respective non-coincident peak loads when PJM is peaking.[38] This will yield a higher resource adequacy value of interties with neighboring regions, thereby reducing the likelihood of load-shed events and the corresponding target planning reserve margins. Other studies, including the simulations presented below, rely on a large number of historical weather years for the study region and neighboring regions to more accurately capture the benefits of tielines and load diversity. For example, the simulations in this report are based on 32 different synthetic annual load shapes for the Study RTO and neighboring regions based on 32 years of actual historical load data in each region.[39]

Supply in External Regions – To calculate tie benefits, it is also necessary to assume the level of supply in each neighboring region and the extent to which such resources will be made available for neighbor assistance during reliability events. This requires assuming reserve margins for each neighboring region, including whether to model the external market at their planning reserve margin target or at their most likely actual level of installed capacity. Further, studies differ in the extent to which each region is assumed to dispatch demand response or other energy-limited resources to provide assistance to its neighbors.

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35 For example, PJM uses a total assumed simultaneous intertie capability or Capacity Benefit Margin (CBM) of 3,500 MW to be used for the purposes of calculating tie benefits. This rating has not been updated since at least 2007, even though the RTO's footprint has expanded several times since then and intertie topology and capability would necessarily have changed at least somewhat. See PJM (2007, 2012c).

36 See Section II.B.

37 See NYSRC (2011), p. 47.

38 See PJM (2012c), p. 75.

39 See Section II.D and Appendix B.5 for additional discussion.

Overall, these differences in study assumptions can substantially affect the planning reserve margins necessary to achieve the chosen reliability targets, as we illustrate further in Section III.B.2 below.

II. APPROACH TO MODELING THE ECONOMICS OF RESOURCE ADEQUACY

To examine the economic implications of the 1-in-10 resource adequacy standard, we conduct a series of reliability simulations using the SERVM model developed by *Astrape Consulting*.[40] In this section, we provide an overview of our simulation approach, including a description of the SERVM model, the characteristics of the hypothetical system we examine, and our key modeling assumptions.

We simulate a hypothetical RTO system that is interconnected to three neighboring systems. This hypothetical RTO is not intended to represent any actual system, but has characteristics similar to those of many U.S. markets. For example, we assume that the Study RTO's resource mix is similar to that of NYISO, while the weather and wind profiles are similar to those in the TVA region. The resource mix, weather, and wind profiles of Neighbors 1, 2, and 3 are similar to those of MISO, PJM, and SoCo. We model both reliability and economic outcomes for the Study RTO in 2016 as the assumed delivery year, as forecasted from a 2013 resource planning year. We describe our modeling approach and assumptions in this section and provide additional detail in Appendix B.

A. STRATEGIC ENERGY RISK VALUATION MODEL OVERVIEW

We use the Strategic Energy Risk Valuation Model (SERVM) to study the reliability and economic implications of the 1-in-10 standard and alternative resource adequacy standards. Like other reliability modeling tools, SERVM probabilistically evaluates resource adequacy conditions by simulating generation availability, load profiles, load uncertainty, transmission availability, and other factors. Based on these reliability simulations, SERVM estimates standard reliability metrics including LOLE, LOLH, and EUE. Unlike other reliability modeling packages, however, SERVM also simulates economic outcomes including hourly generation dispatch, import-export dynamics, ancillary services, emergency procedures, and investment costs. SERVM estimates hourly and annual production costs, customer costs, market prices, net import costs, load shed costs, and generator energy margins as a function of planning reserve

[40] The SERVM package was originally developed by SoCo in the 1980s to support resource adequacy decisions and significant resources have been devoted to develop the model since then in a number of applications by various companies. Today, SERVM is managed by *Astrape Consulting*, who provides consulting services and licenses of SERVM to inform resource adequacy decisions to a number of clients, including LG&E, KU, SoCo, TVA, CleCo, SCANA, Duke Energy, Progress Energy, and Terna (the Italian system operator).

margins. These results allow us to compare these variable costs against the incremental capital costs required to achieve the higher planning reserve margins.[41]

The multi-area economic and reliability simulations in SERVM include an hourly chronological economic dispatch that is subject to inter-regional transmission constraints. Each generation unit is modeled individually, characterized by its own economic and physical characteristics. Planned outages are scheduled in off-peak seasons to minimize the impact on reliability, while unplanned outages and derates occur stochastically using historical distributions of time between failures and time to repair. Load, hydro, wind, and solar conditions are modeled based on profiles consistent with individual historical weather years. Dispatch limitations and limitations on annual energy output are also imposed on certain types of resources such as demand response, hydro generation, pumped storage, and environmentally-limited combustion turbines (CTs).

The model implements a weekly commitment algorithm in each study region that considers the outlook for weather and planned generation outages. The model then conducts an hourly economic dispatch of baseload, intermediate, and peaking resources, including an optimization of transmission-constrained inter-regional power flows to minimize total cost. Pumped storage resources are dispatched economically to capture differences in pricing between peak and off-peak periods. During most hours, hourly prices in each region reflect marginal production costs, with importing regions realizing higher prices when import constraints are binding. During emergency and other peaking conditions, SERVM simulates scarcity prices that exceed generators' marginal production costs as explained further below.

To examine a full range of potential economic and reliability outcomes, SERVM conducts a Monte Carlo analysis over a large number of scenarios varying with both demand and supply conditions. Because reliability events occur only when system conditions that reflect unusually high loads or limited supply, these simulations must capture wide distributions of possible weather, load growth, and generation performance scenarios. In this study, we incorporate 32 weather years, 6 economic load forecast error points, and 50 draws of generating unit performance for a total of 9,600 scenarios for each simulated reserve margin case, with each scenario simulating all 8,760 hours of the year.[42] This large number of simulations is necessary for accurately characterizing the reliability and economic implications of different planning reserve margins because the vast majority of reliability-related costs are incurred within a small

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[41] Note that SERVM as a modeling tool does not endogenously estimate capital costs, which are reflected as a fixed annual cost (in $/kW-year). Total capacity costs simply increase as a function of the planning reserve margin being evaluated. The question of whether a particular reserve margin is actually achievable or realistic under various market designs, including in regions with capacity markets, energy-only markets, or cost-of-service regulation, depends on whether those markets have been constructed such that investors are able to recover their fixed costs at that reserve margin. We examine these and other market design implications of our modeling exercise in Section IV below.

[42] Note that SERVM results incorporate this set of scenarios for each reserve margin level simulated for the base case and each alternative case we present in this report. Depending on data availability and study needs, SERVM can incorporate any number of weather, hydro, wind, solar, economic forecast, and other scenarios. For the purpose of this study and to facilitate exploration of a larger number of alternative cases, we streamlined the simulation effort by modeling only 50 draws of generation outage conditions. In other studies, *Astrape* typically models several hundred generation outage draws.

number of simulation runs (or, in real-world systems, in a small number of infrequent emergency events). Such reliability events are typically triggered by rare circumstances that reflect a combination of extreme weather-related loads, high load-growth forecast error, and unusual combinations of generation outages.

To properly capture the magnitude and impact of reliability conditions during extreme events, a critical aspect of this modeling exercise the economic and operational characterization of emergency procedures. For this reason, SERVM simulates a range of detailed emergency procedures, accounting for energy and call-hour limitations, dispatch prices, voltage reductions, operating reserve depletion, dispatch of economic and emergency demand-response resources, and administrative scarcity pricing.

B. System Topology and Transmission Assumptions

We evaluate the economic reliability implications of resource adequacy by analyzing a hypothetical RTO interconnected to three adjacent systems. This hypothetical RTO has system characteristics similar to those of many U.S. markets, but does not exactly reflect any one region in particular. By constructing such a generic system as a Base Case and comparing those results to a series of Change Cases, we are able to examine our results under a variety of realistic resource mixes, load profiles, market structures, and economic assumptions. This allows us to draw conclusions that are relevant to a number of real-world systems without narrowing our focus to any individual real-world system. As summarized in Figure 3, the Study RTO is a 50,000 MW system interconnected with three similarly-sized regions.

The transmission capabilities shown in the figure represent the maximum import and export capabilities of the interties, which vary stochastically over a distribution between 60% and 100% of the maximum. As we explain further in Appendix B.1, the maximum simultaneous import capability to the study region is 11,000 MW but drops to below 8,000 MW in 50% of all hours.[43] We assume that no portion of the interties' transfer capability is dedicated to the firm import of external resources committed towards resource adequacy of the Study RTO.[44]

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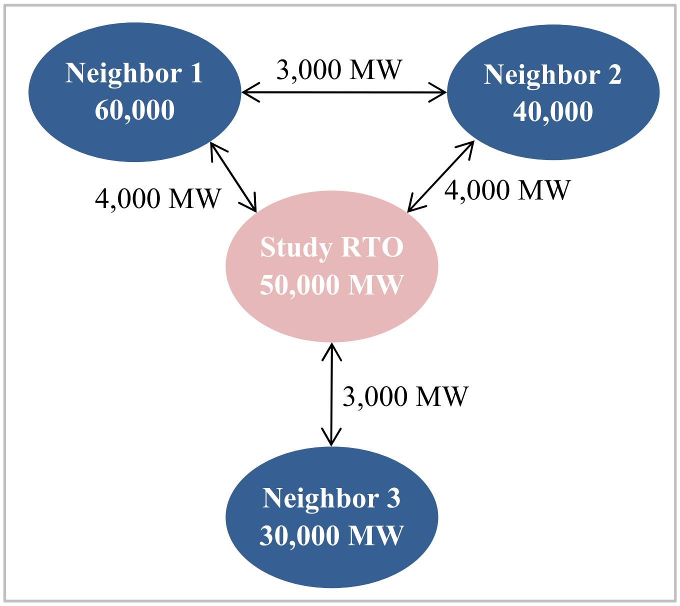
43 We statistically represent the variable availability of inter-regional transmission capability, but do not explicitly model the various reasons that interties may be partly unavailable at different times. However, we note that some of these factors include line outages, path ratings that may vary with temperature or operating procedures that sometimes limit imports to avoid great exposure to single large contingencies.

44 In real-world systems, it is important to distinguish the portion of each intertie that is dedicated to firm capacity imports under firm Point-to-Point (PtP) transmission from the remaining portion of the interties that can assist internal resource adequacy on a non-firm basis as long as the neighboring system's resources exceed the needs of their native load. For our purposes we treat all external resources as being available to the Study RTO on a non-firm basis driven by economics, but assume that in emergency events each system will have first call on their internal generating resources. We discuss these topics further in Section III.B.2 below.

Figure 3
Transmission Topology and Non-Coincident Peak Loads



Notes:
Stated intertie ratings represent the path maximum.
See Appendix B.1 for additional detail on intertie availability.

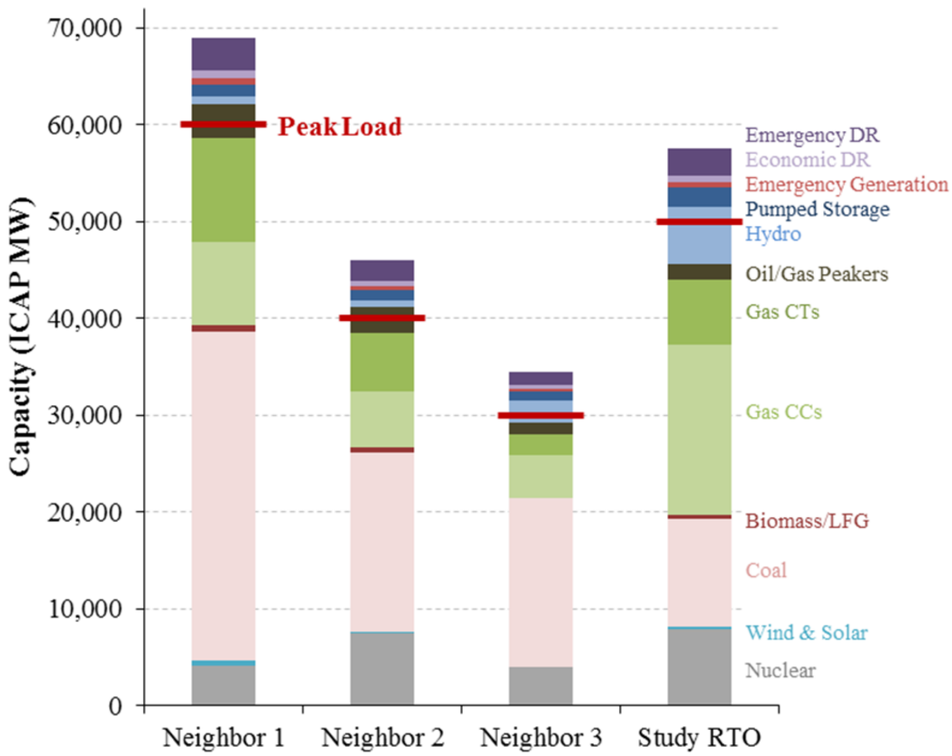
C. Resource Assumptions

To characterize the generation and demand response resources available to meet load the simulated Study RTO and the neighboring regions, we assume resource characteristics consistent with many real-world systems. We present here a description of our assumptions and approach to modeling system supply, including each region's resource mix, supply curves, generation resource availability, and demand response resources.

1. Resource Mix

Figure 4 summarizes the supply resource mix in the Study RTO and the neighboring systems, with the Study RTO represented at the 15% reserve margin. We model each system with a reasonable proportion of baseload, intermediate, and peaking resources. Each region also has some energy-limited and intermittent resources such as hydro, pumped storage, wind, solar, and emergency demand response. Some characteristics of the Study RTO that materially impact study results include that: (1) the Study RTO depends more heavily on natural-gas-fired plants while the neighboring regions have more coal, meaning that the Study RTO will tend to be a net importer at the assumed natural gas and coal prices; (2) the 10% hydro penetration in the Study Region is higher than in neighboring regions, adding some additional uncertainty into the Study RTO's resource availability; and (3) assumed DR penetration is 6-7% of peak load depending on the region, which is consistent with many current markets but below the penetration levels expected in coming years in some of the eastern RTOs, such as PJM and ISO-NE.[45]

Figure 4
Installed Capacity and Resource Mix



Notes:
All regions shown at 15% planning reserve margin, although simulated reserve margins vary by model scenario.
Wind and solar shown at capacity credits of 15% and 25% respectively, which is the same as their contribution to the reserve margin (other resources are represented at nameplate)

We assume a planning reserve margin of 15% is maintained in all neighboring regions, similar to the current reserve margin targets in a number of actual North American markets. We calculate reserve margins based on nameplate capacity for all resource types except for wind and solar, to which we assign capacity value at 15% and 25% of nameplate, respectively. Economic and emergency demand response capacity are included on the supply side in the reserve margin calculation.[46] The load impact of voltage reduction is not considered in the reserve margin

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[45] For example an ISO/RTO Council Study estimated a 6.6% overall DR penetration level across all North American RTOs as of 2008, while PJM and ISO-NE's capacity auctions for 2015/16 and 2016/17 cleared DR commitments equal to 9.9% and 9.3% of peak load respectively. See IRC (2009), p. 26; PJM (2013a); and ISO-NE (2013).

[46] Section II.C.4 explains our approach to modeling economic and emergency DR, including a description of how we distinguish these two resource types from a modeling perspective.

calculation, but we do implement voltage reductions to avoid shedding load in our simulations as discussed in Section II.E.

2. Energy Market Supply Curve

In modeling production costs for each supply resource, we assume plant costs and efficiencies that are typical for each resource type and that vary among individual units. The aggregate system supply curves for each region are shown in Figure 5 and account for fuel costs and variable operations and maintenance (VOM) costs.[47] We assume delivered fuel costs as projected for the year 2016 in the *Annual Energy Outlook*, with coal at $2.50/MMbtu, natural gas at $5/MMbtu, and fuel oil at $25/MMbtu.[48]

As Figure 5 shows, the Study RTO's supply stack is similar to, but not identical to, those of its neighbors. Over most of the relevant dispatch ranges from 50% to 100% of peak load, the Study Region's available supply from natural gas combined cycles (CCs) is slightly more expensive than supply from the neighboring regions that have a higher share of lower-cost coal resources. At the very top of the supply stack shown in Figure 5, the Study RTO supply curve is also higher because it depends somewhat more heavily on high-dispatch-cost demand response resources and emergency hydro for super-peaking periods, while the neighboring regions have more peaking gas and oil units. The highest-price portion of the supply curve at dispatch costs above $500/MWh is not shown in this figure, but causes the Study RTO supply curve to rise sooner because it is shown as a percentage of peak load. We more fully describe the emergency procedures, economic costs, and energy pricing mechanisms assumed during high-price events in Section II.E below.

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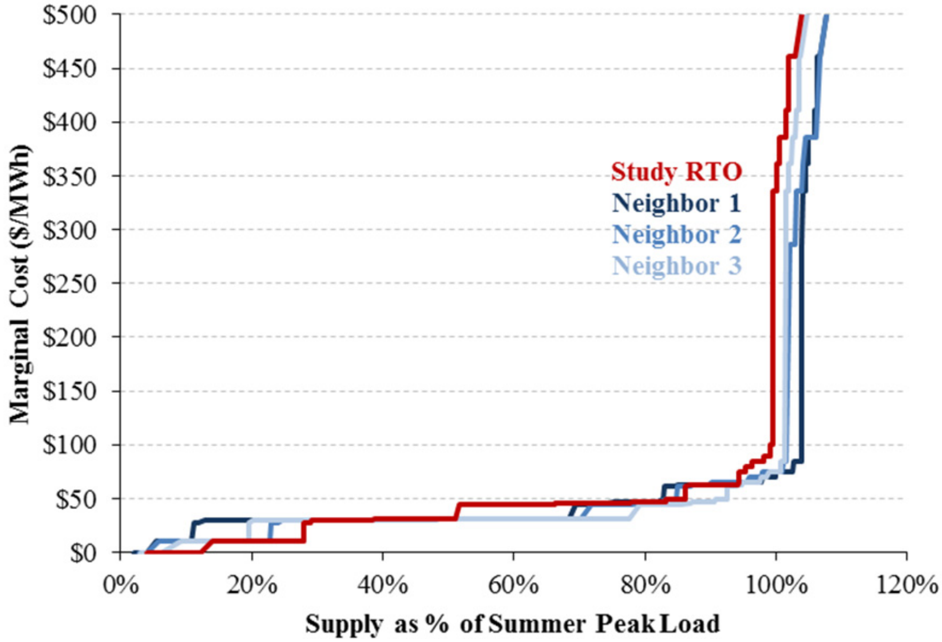
47 While SERVM also has the capability to model a host of other unit parameters including startup and shutdown costs, minimum up and down times, emissions costs, and heatrate curves, we exclude these parameters from our study for simplicity.

48 Specifically, we use average national prices as-delivered to the electric power sector from the High Economic Growth case in the 2012 *Annual Energy Outlook*. Fuel prices reported in nominal dollars, see EIA (2012).

Figure 5
Energy Market Supply Curve by Region



Notes:
Wind and solar capacity derated to 15% and 25% of nameplate.
Pumped storage represented at a $0/MWh, although dispatched only at daily peak.
$2,000/MWh emergency DR and $3,000/MWh emergency hydro not shown due to scale.

3. Generation Outage and Availability Modeling

A major component of reliability analyses is modeling the availability of supply resources after considering planned outages, forced outages, intermittency, and energy limitations. We use SERVM to simulate generation resource availability on a unit-specific basis, but characterize resource utilization and availability differently depending on resource type:

Thermal Resource Outages – We assume planned and forced outage rates for thermal generation resources based on unit type and size, consistent with recent NERC data from the Generation Availability Data System (GADS).[49] SERVM schedules planned outages during low-demand periods in the spring and fall, but models maintenance and forced outages stochastically. Partial and full forced outages occur stochastically for each individual unit based on probability distributions accounting for time-to-fail, time-to-repair, and partial outage derate percentages. Similarly, SERVM models the need for maintenance outages stochastically, but implements these outages with some scheduling flexibility during off-peak hours to the extent feasible. This outage modeling approach allows SERVM to capture the potential for severe shortages caused by a number of coincident outages.[50] Appendix B.2 contains additional detail describing forced and maintenance outage modeling.

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49 See NERC (2011b).

50 Capturing the possibility of such low-probability, high-impact events is an advantage of the unit-specific Monte Carlo outage modeling used in SERVM. Other production cost and reliability models typically use

Continued on next page

Hydroelectric Availability – We model 30 years of hydro resource availability using monthly hydro generation data for the respective regions and historical years used in our load modeling described in Section II.D.1 below.[51] These hydro resources have varying levels of flexibility as either run-of-river plants with a fixed schedule, peak shaving plants that are dispatched based on the difference between peak and off peak prices, or emergency hydro capacity dispatchable at $3,000/MWh. See Appendix B.3 for additional detail on hydro resource modeling.

Pumped Storage – We characterize pumped storage resources according to reservoir size, pumping efficiency, and capacity and dispatch these resources to maximize their economic value assuming imperfect foresight of hourly energy prices.[52] The units pump during off-peak hours and generate during on-peak hours, but only when the anticipated price differential is large enough to overcome pumping efficiency losses.

Intermittent Resources – We model intermittent wind and photovoltaic solar resources assuming non-dispatchable hourly generation profiles for the Study RTO's modest penetration levels of 3.8% and 0.09% for wind and solar respectively in the Base Case.[53] For wind generation, the hourly profiles reflect three years of data from the *Eastern Wind Integration Transmission Study* (EWITS); for solar they reflect one year of data from *PV Watts*.[54] In both cases, the hourly profiles are consistent with the weather data for the four regions used in our load modeling. To capture intermittent resource availability as well as inter-regional weather correlations, SERVM randomly draws a particular day within the month being simulated and uses hourly profiles from that same date for each modeled region. See Appendix B.4 for additional detail on our intermittent resource assumptions.

After SERVM accounts for all of these factors, the model determines the aggregate quantity of resources available for economic dispatch as described in Section II.A above.

4. Economic and Emergency Demand Response Resources

Most regions have a variety of DR programs that can be dispatched whenever a certain price or reliability event occurs.[55] While the nuances of each variety of DR program could be modeled in SERVM consistent with a region's actual DR portfolio, we focus on simulating two broad categories of DR programs:

Continued from previous page

a simpler convolution method, resulting in a distribution of outages that may under-estimate the potential for extreme events, especially in small systems.

51 Monthly hydro data for each region obtained from EIA (2013a).

52 Specifically, to reflect the scheduling activity of a pumped hydro resource with slightly imperfect foresight of actual market prices in each hour, we implement this hourly scheduling using a price profile from the same date from a different run of SERVM with the same load profile but with different outages.

53 These penetration levels are calculated as nameplate as percent of summer peak load.

54 ETWITS and PV Watts are both developed by the National Renewable Energy Laboratory, see NREL (2013a-b).

55 For a survey of various types of demand response programs, see the summary and referenced supporting documentation in IRC (2009), Section IV and IRC (2010).

Emergency DR – The majority of existing RTO-dispatchable DR programs would be most accurately described as "emergency" or "capacity-only" resources. Emergency DR programs contribute to resource adequacy and increase planning reserve margins because they can be dispatched during reliability events. These resources will not dispatched on an economic basis, but will be triggered during emergency conditions according to the system operator's emergency procedures as explained in Section II.E below. We assume that these DR resources have a curtailment cost of $2,000/MWh and a 100 hour-per-year maximum dispatch limit.[56]

Economic DR – A minority of existing RTO-dispatchable DR programs are what we classify as "economic" DR resources. These resources bid into the energy market at a resource-specific strike price that reflects the customer's willingness to pay for energy. Whenever wholesale energy market prices exceed this strike price, the resources would be dispatched just like a generator that offered into the market at the same offer price. Economic DR resources also contribute to planning reserve margins, but we assume they do not have any limit on the annual call hours. We simulate a supply curve of economic DR resources with strike prices ranging from $100 to $1,000/MWh in the Base Case and over a wider range of strike prices up to the price cap of $7,500/MWh in a high economic DR penetration case as explained further below.[57]

Our Base Case simulations assume DR penetration levels of 6-7% of peak load across the different regions as shown in Table 3, consistent with the penetrations in many actual systems today.[58] We further assume for all regions that 80% of the DR resources are emergency DR while 20% are economic DR programs.[59]

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56 It is standard practice among many systems to have "emergency" or "capacity" DR programs that are triggered by emergency conditions rather than based on energy market prices. Many of these programs also have call-hour or other types of restrictions that limit their total annual use, but there is no standard call-hour limitation and so our 100 hour limit is somewhat arbitrary. For example, PJM's limited DR product can be called only in summer peak periods for up to 10 calls and up to 6 hours per call. The per-call cost of these programs is also relatively arbitrary, and so we assume an interruption cost that is consistent with the price cap applicable in some markets that implement these programs as well as the order in which these emergency resources are called as discussed further in Section II.E. See IRC (2010).

57 Economic DR suppliers may offer at any strike price of their own choosing, but at a price that reflects the underlying customer's willingness to pay for energy. We assume an offer price range of $100-$1000/MWh in the Base Case, reflecting the assumption that economic DR would typically bid only at prices above the average retail price for energy. We also evaluate an alternative scenario with substantially more economic DR, as explained further below and illustrated in Figure 6.

58 For example, see IRC (2009), p. 26.

59 This ratio of emergency DR to economic DR is based on the current proportion in PJM, see PJM (2013c), p. 5.

Table 3
Base Case Demand Response Penetration

Region	Demand Response Capacity		Total DR
	Emergency *(MW)*	Economic *(MW)*	Penetration *(% of Peak Load)*
Study RTO	2,778	694	6.9%
Neighbor 1	3,380	845	7.0%
Neighbor 2	2,132	533	6.7%
Neighbor 3	1,424	356	5.9%

Notes:
Base Case DR penetration levels are consistent with levels currently achieved in many real-world RTOs, see IRC (2009), p. 26,

We simulate a series of alternative DR cases to evaluate the implications of growing levels of DR penetration. The consequences of relying more heavily on DR for resource adequacy purposes will be particularly important over the coming years in PJM, which has attracted large quantities of DR commitments through its forward capacity market, amounting to 9.9% of normalized peak load by 2015/16.[60]

At PJM's high historical reserve margins, increasing quantities of DR would not be expected to substantially impact PJM's energy market pricing or reliability outcomes. This is because the "generation-only" reserve margin was high enough to meet the reliability target even without any DR commitments. This will change in the coming years, however, because the large increase in DR penetration is also enabling the retirement of a large quantity of uneconomic generation resources.[61] Displacing generation with DR resources has substantial implications, because the "generation-only" reserve margin will soon be far below the reliability target. This means that DR resources will have to be dispatched more frequently. It appears likely that this combination of factors will: (a) cause dispatch-limited DR to have a somewhat lower reliability value, a concern that PJM has already addressed by introducing multiple DR products; (b) require DR suppliers to reevaluate their willingness to sell capacity at a particular price; (c) result in higher energy market prices during scarcity events; and (d) motivate more DR resources to participate as "economic" rather than "emergency" resources.[62]

We evaluate the consequences of high levels of DR penetration in two alternative scenarios. We begin with a no-DR case in which all DR is removed from the Study RTO, and with total generation resources sufficient to maintain a 15% reserve margin. We then evaluate the consequences of displacing generation with DR by removing gas CTs and replacing them with

[60] See PJM (2013a).

[61] For additional documentation of these displacement quantities, see PJM (2013a); Newell and Spees (2013); and Spees, *et al.* (2013).

[62] See additional discussion of these topics in Sections III.C and IV.C below as well as Newell and Spees (2013) and Spees, *et al.* (2013). For an explanation and discussion of PJM's multiple DR products, see Pfeifenberger, *et al.* (2011a), Section VI.C.1.

either: (1) Emergency DR in one scenario; or (2) Economic DR in a second scenario. In both the Emergency and Economic DR cases, we model DR penetration levels of 0%, 5%, 10%, and 20% of peak load while maintaining a 15% reserve margin across all runs.

We assume that Emergency DR has the same characteristics as in the Base Case, with a \$2,000/MWh dispatch cost and a 100 hour dispatch limit (although we also test the impact of varying the dispatch limit). We model Economic DR differently, however, with Economic DR resources offering over a wide range of prices up to the price cap of \$7,500/MWh, as shown in Figure 6. This Economic DR supply curve is based on available evidence of how responsive customers could be to high energy market prices, but required us to make additional assumptions about how customers would behave at penetration levels that are far above historical experience.[63] To create this economic DR supply curve, we assume that the aggregate customer base has a constant elasticity of demand, and adjust this elasticity to achieve the 5% to 20% total economic DR quantity up to the energy market maximum price of \$7,500/MWh.[64] The shape of this economic DR supply curve is generally consistent with the results of various real-time and critical-peak-period pricing experiments, although those experiments are more often centered on estimating peak load reductions or on-peak versus off-peak elasticities of substitution.[65]

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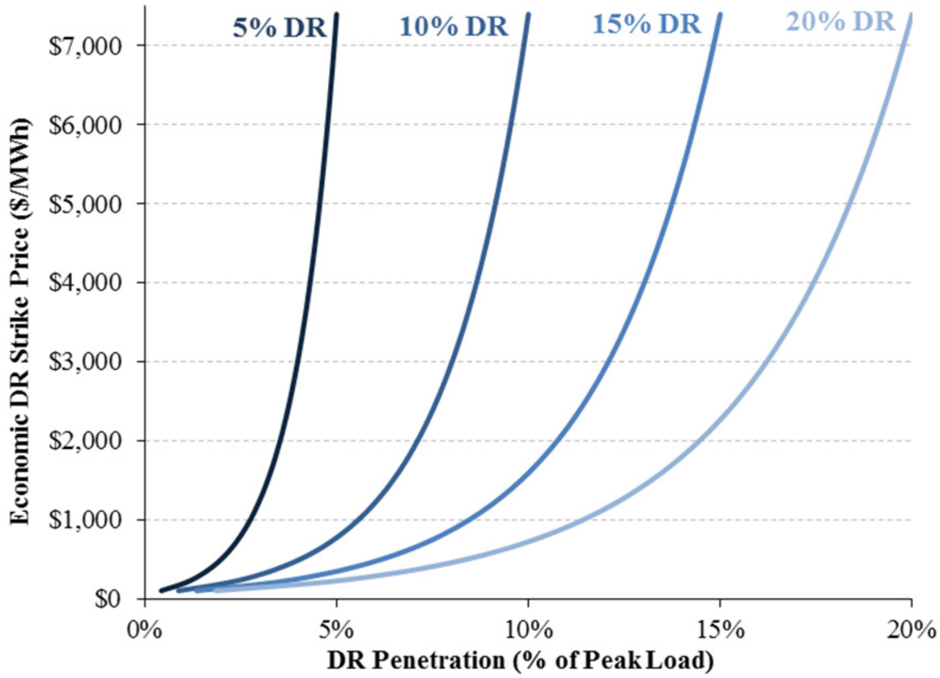
[63] For example, in PJM, economic DR offers in the energy market are only approximately 1.4% of summer peak load, see PJM (2013c), p. 5.

[64] More specifically, we assume that customers are represented by the formula $Q = a \cdot P^E$, where: Q is weather-normalized peak load; a is a constant; and P is the customer-realized electricity price including energy (at \$57/MWh on average at the 15% reserve margin as calculated in the Base Case), capacity (at \$9/MWh at the 15% reserve margin as calculated in the Base Case), and transmission and distribution (T&D) charges (at \$34/MWh), consistent with the national average. We calculate the parameters a and E, assuming that peak load would be at the normalized (50/50) forecast (consistent with the annual average energy price), reduced by the total DR penetration percentage at the maximum energy market price of \$7,500/MWh. Average T&D charges are based on 2011 annual average charges of delivery-only electric providers averaged across all customer classes, see EIA (2013b).

[65] These economic DR supply curves are consistent with constant demand elasticities of -0.012, -0.024, -0.038, and -0.052 for the simulated 5%, 10%, 15%, and 20% DR penetration cases. These elasticities are generally consistent with estimates from various pilot studies of customer price-responsiveness to real-time and critical peak pricing programs, although those studies often estimate elasticities of substitution or simple peak reductions as a function of price or price ratio. See, for example, Faruqui and Sergici (2010, 2011, 2013).

Figure 6
Energy Market Supply Curve for Economic DR Penetration Case



Notes:
Calculated assuming constant demand elasticities of -0.012 to -0.052, see also Footnotes 64 and 65.

D. Load Modeling

Load uncertainty is a key factor driving reliability events. We separately account for the two primary drivers of load uncertainty: (1) weather, which varies from year to year over a wide range of hourly profiles; and (2) economic load forecasting uncertainty, which characterizes the uncertainty in load growth independently of weather.

1. Weather Uncertainty

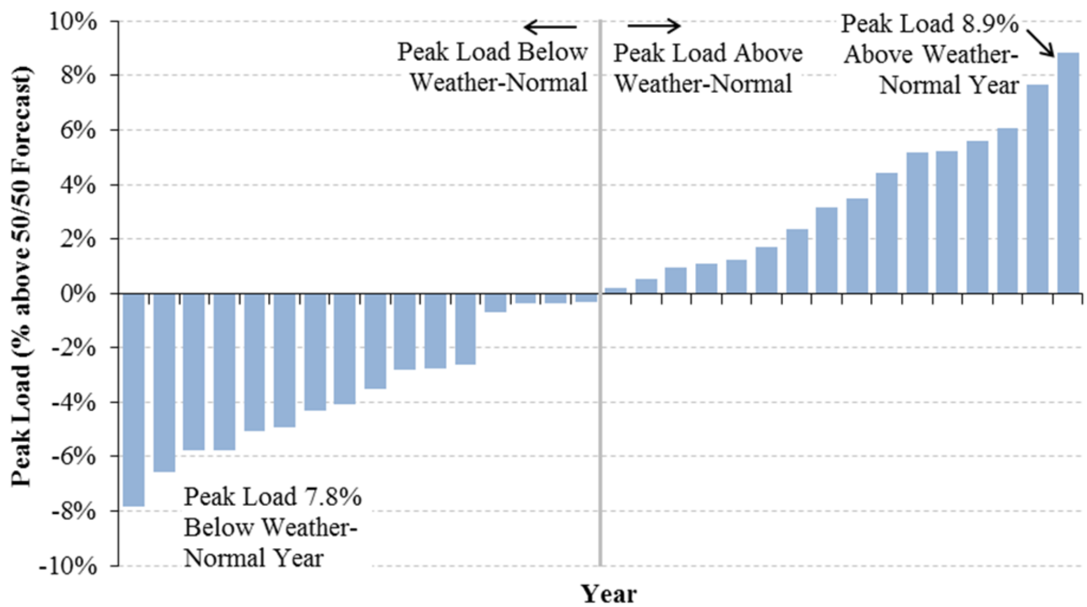
To characterize load uncertainty caused by weather, we use 32 years of historical hourly temperature and rainfall data and five years of historical hourly load data for each study region. Weather and load profiles in the Study RTO are based on data for TVA, while Neighbors 1 through 3 are based on central MISO, western PJM, and SoCo respectively.[66] We use the most recent five years of hourly weather and loads to develop a statistical relationship between load and weather, accounting for a number of variables including month of year, time of day, and day of week. We use this relationship to create 32 synthetic load profiles that are consistent with each of the 32 historical weather years. Figure 7 shows that the resulting peak loads range from -

[66] Hourly Historical Load Data for the Study RTO (based on TVA) and Neighbor 3 (based on SoCo) are derived from FERC 714 Forms. Load data for Neighbor 1 (based on central MISO) and Neighbor 2 (based on western PJM) are derived from RTO data. All hourly weather data are from the National Oceanic and Atmospheric Administration (NOAA). See FERC (2013); PJM (2013b); MISO (2013a); and NOAA (2013).

7.84% below to 8.85% above the weather-normalized peak load in the Study RTO. Each weather year also has a different overall load duration curve, with some years having sustained heat waves that cause a much larger number of high-demand hours.

By using weather profiles from the same historical years for each of the modeled regions, we are able to capture the inter-regional correlation in loads and level of load diversity on high-demand days. Since weather patterns can differ substantially across the four regions on summer days, the timing of each region's highest peak loads will be different as well. If one region is at its system peak load but a neighboring region is not, the load diversity between the two systems will reduce their combined resource needs. Overall, the load diversity across the four regions yields a coincident peak load of 174,668 MW compared to the sum of regional non-coincident peaks of 180,000 MW, or a 3% reduction due to load diversity. Appendix B.5 contains additional detail on weather uncertainty in load modeling.

Figure 7
Study RTO Summer Peak Load under Different Weather Profiles



Notes:
Range in peak load shown is due to weather uncertainty alone, without economic load growth forecasting error.

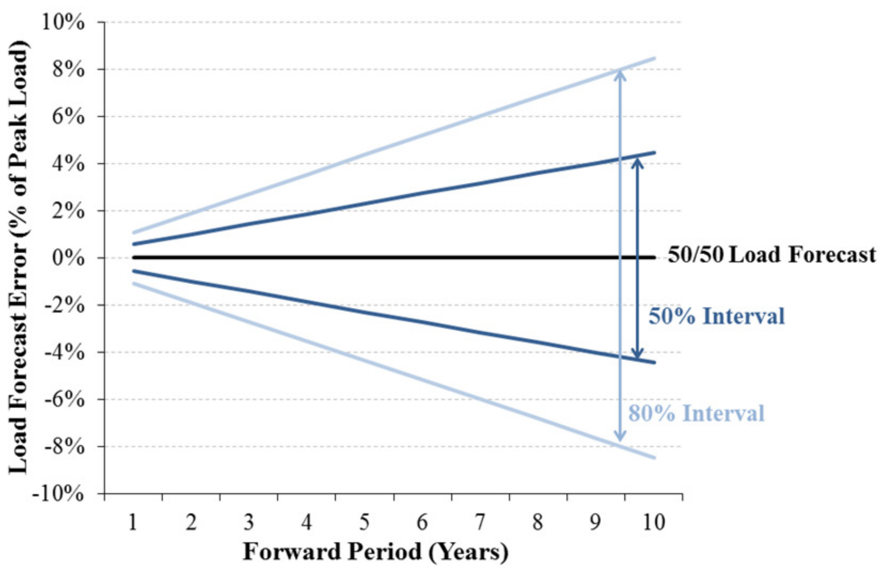
2. Economic Load Growth Forecasting Uncertainty

Load uncertainty is driven not only by year-to-year volatility in weather patterns, but also by an underlying load growth forecasting error over the forward study period. This is the level of uncertainty in 2016 peak load as would be forecast in 2013, even if the modeler were certain that 2016 would be a "weather normal" year. An important driver of that uncertainty for resource planning purposes is the uncertain outlook for economic growth. Unanticipated economic growth or downturns can result in peak loads that are substantially higher or lower than the forecast. Further, economic uncertainty increases with the forward planning period; this is unlike weather-based uncertainty, which is constant across all forward periods.

Figure 8 shows how the assumed level of the economic load growth forecasting error increases with the forward planning period. This assumed economic forecast error is based on the last 20 years of Congressional Budget Office (CBO) four-year forward forecasts of U.S. national real gross domestic product (GDP) growth compared to actual GDP growth.[67] We translate this economic growth uncertainty into load forecast uncertainty by assuming that electricity load will grow at 40% of the GDP growth rate, reflecting the approximate relationship between electric energy consumption and GDP growth over the period 1980 to 2010.[68]

Note that Figure 8 shows only the peak load forecasting error related to underlying economic uncertainties and excludes the portion of load uncertainty related to weather. The chart shows that, although peak load forecast error is zero on average, the spread in possible outcomes increases over time so that the 80% confidence interval for economic load growth forecasting errors increases from a spread of only 2.2% at one year forward, to 5.4% three years forward, and to 17% ten years forward. Note that increasing the forward planning period in a reliability analysis such as ours will translate into a higher likelihood of reliability events at any given reserve margin, and will therefore result in setting a higher reserve margin requirement.

Figure 8
Economic Load Forecast Error vs. Forward Planning Period



Notes:
Load forecast error is normally distributed around zero with a 0.8% standard deviation at one year forward, with standard deviation increasing 0.6% for each additional year.

In our Base Case simulation, we assume an economic load forecast error consistent with a four-year forward planning exercise. This assumption is consistent with many system operators' planning studies and is approximately consistent with the lead time for developing a new

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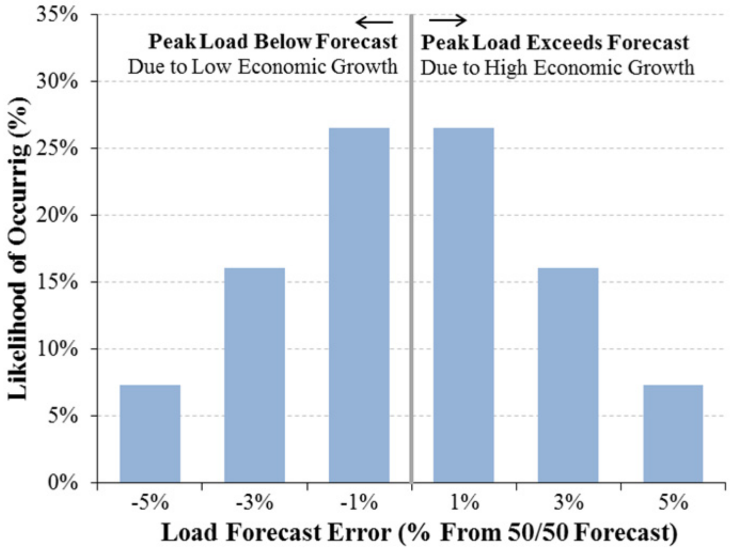
67 See CBO (2012).

68 During this 30-year period, electric energy consumption rose by 2% per year on average while GDP grew by approximately 5% per year, suggesting the relationship is approximately 0.4% load growth for every 1% of nominal GDP growth. See CRS (2012); Data360 (2013).

combustion turbine plant.[69] The choice of this forward period for our simulations implicitly assumes that all resource planning decisions are locked in on a four-year forward basis with no shorter-term flexibility from uprates, DR procurement, delayed retirements, or off-system power purchase agreements (PPAs). However, if there is some flexibility to procure a portion of supply on a shorter-term basis, then total system costs could be reduced by: (1) maintaining a lower reserve margin while meeting the same reliability requirement; and (2) capturing the option value of waiting to procure a portion of resources until after some of the economic forecast uncertainty has resolved. We more fully explain and examine the economic and reliability implications of the forward planning period in Section III.A.5 below.

We represent this four-year forward distribution using six discrete levels of economic load forecast error with each assigned a specific probability level as summarized in Figure 9. We apply this economic forecast error equally to the Study RTO and the four neighboring regions, assuming economic load growth uncertainty is perfectly correlated across the study regions.[70]

Figure 9
Probability of Various Levels of Economic Load Forecast Error



Notes:
Economic forecast error consistent with a four-year forward period.

E. Scarcity Conditions

To calculate production costs and market prices during most hours, SERVM uses hourly supply curves of available resources in each region. The higher the generation outages and load in a particular hour, the higher the marginal dispatch cost and market price as explained in

[69] Note that total lead times including development, siting, and permitting may be substantially longer, but these phases of development represent a relatively small component of total plant costs.

[70] While there will likely be at least some diversity of load forecasting error across the five regions, the use of U.S.-wide GDP growth forecast already captures at least some such diversity because forecast error for economic growth within a particular region generally exceeds that of the nation as a whole.

Section II.A above. However during scarcity conditions, when system demand plus operating reserves requirements approach or exceed available supply, system operators must implement a series of emergency procedures to maintain system stability. One critical aspect of our modeling exercise is simulating: (a) what emergency procedures are implemented at each level of scarcity including the most extreme cases when load must be shed as well as somewhat less severe scarcity events; (b) what system costs are imposed under each type of emergency event; and (c) what market prices would prevail during these events.

For the purposes of our simulations, we assume that prices will always be set at marginal system cost, including during scarcity events when emergency procedures must be implemented. We also assume that non-emergency dispatch and emergency procedures will be implemented in order of ascending marginal system costs, as described in Table 4. This series of emergency procedures is generally consistent with the emergency actions implemented by many system operators, but is not intended to exactly reflect any particular system.[71]

Generally, the marginal system costs and resulting market prices represented in Table 4 increase with the severity of a shortage event up to the maximum energy price at the average customer value of lost load.[72] In our Base Case, we assume that the value of lost load is $7,500/MWh, representing the approximate value that the average customer places on service interruptions during load shed events. Customers' VOLL is a highly uncertain parameter that has been estimated over a wide range. Most academic and industry studies estimate residential customers' VOLL at below $5,000/MWh, while industrial and commercial customers' VOLL can exceed $15,000/MWh on average. To demonstrate the impact of this assumption, we analyze the sensitivity of our modeling results to this parameter in Section III.D.

We assume that each system is also willing to implement some (but not all) of these procedures to benefit neighbors when those systems are experiencing higher-cost emergency events. Calling Emergency DR is the most costly emergency procedure that each system will implement to maintain exports, but exports will be curtailed if any costlier emergency procedures would be required. In other words, we assume that system operators will not be willing to dispatch emergency hydro, endure operating reserves shortages, implement voltage control, or shed internal load for the benefit of neighboring systems.

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71 For example see AESO (2012) or PJM (2013d).

72 A rich literature exists demonstrating that VOLL is the efficient energy market price to impose in extreme shortage events during which load must be shed. For additional discussion, see Section IV.A.2 below.

Table 4
Marginal Costs and Prices by Resource Type and Emergency Procedure

Marginal Resource or Emergency Procedure	Description
Generation $0 to $460/MWh	During most hours, marginal system cost is the marginal dispatch cost of generation, ranging from $0/MWh (for wind and solar) to approximately $460 (for inefficient oil peakers), see Section II.C.2.
Economic DR $100 to $1,000/MWh	Economic DR has a marginal cost of $100-$1,000/MWh in the Base Case, or up to the price cap in a high DR case, see Section II.C.4.
Emergency Generation $500/MWh	We assume that all resources have an "economic maximum" capacity rating used under normal conditions, and an "emergency maximum" rating that is 1% higher.[73] Achieving this higher emergency output level imposes substantial maintenance costs, assumed at $500/MWh.
Emergency DR $2,000/MWh	Emergency DR is available for dispatch through the supply stack similarly to generation resources at a $2,000/MWh price, although these resources are limited to a total of 100 call hours per year as explained in Section II.C.4.
Emergency Hydro $3,000/MWh	Emergency hydro is peaking resource that is costly and use-limited, with the costs being driven by the opportunity cost of not saving these resources for another time as well as environmental and societal costs imposed if reservoir levels are depleted.
Operating Reserves Shortages $3,000 to $7,000/MWh	Depleting operating reserves imposes marginal system costs by exposing the market to greater contingency risks. We model marginal system cost consistent with the administrative scarcity pricing curve shown in Figure 10 below.
Voltage Reduction $7,000/MWh	We assume that load can be reduced by 1% if implementing a system-wide voltage reduction at a marginal cost of $7,000/MWh.[74]
Firm Load Shedding $7,500/MWh	The maximum price and marginal system cost is at the assumed VOLL of $7,500/MWh, based on a mid-range estimate of customer-specific VOLL, assuming that load-shed events are more focused on locations with non-critical loads and more residential (rather than commercial-industrial) areas of the system .

73 Distinguishing between generators' economic and emergency maximum ratings is common, with the emergency maximum output being dispatched only during scarcity conditions. For example see AESO (2012), p. 6; PJM (2013d), p. 23.

74 The costs imposed by this type of voltage curtailment have not been widely studied, although the costs of different types of voltage sag or power quality events have been evaluated in some studies. We assume a cost slightly below the VOLL, consistent with the economics implied by the fact that voltage reductions, if implemented at all, are typically invoked only after all other procedures as a last resort to avoiding firm load shed, for example see PJM (2013d), p. 14; Sullivan, *et al.* (2009); CEER (2010).

As explained in Table 4, most resources are functionally modeled as part of the supply stack, including resources such as economic DR, emergency generation, emergency DR, and emergency hydro. These resources are always available for dispatch, but they are available only at high strike prices and so are dispatched only under scarcity conditions. However, for the most extreme scarcity events when other emergency procedures must be implemented, prices are set according to the administrative scarcity pricing function described in Figure 10. The figure shows that the administrative price would be set as a function of the hourly supply cushion, equal to the total quantity of non-emergency and emergency resources available in the supply stack minus the hourly load.

Any time the hourly supply cushion (hourly supply stack minus load) drops below a 5% operating reserves target, the system operator will have to implement an emergency measure to maintain supply-demand balance. First, the system will endure an operating reserves shortage relative to the 5% target maintained under normal system conditions. Simulated prices increase as the size of the operating reserves shortage increases, according to the specified administrative scarcity function. However, under no circumstances can operating reserves be allowed to drop below the 2% minimum level that must be maintained for system security even during load shed events. This downward-sloping portion of the administrative scarcity pricing function operates similarly to the "operating reserves demand curves" and equivalent mechanisms implemented by several RTOs over recent years.[75] We assume that this administrative scarcity pricing curve reflects the marginal system cost imposed by operating reserve shortages. These marginal system costs can be quite high because depleting operating reserves increases the risk of load shed events and even cascading outages that could be triggered by generation or transmission contingencies or sudden changes in load or wind generation.[76]

Once operating reserves are at the minimum level of 2%, the system operator will implement: (a) a system-wide voltage reduction that is assumed to achieve a 1% reduction in load at a marginal system cost of $7,000/MWh; and finally, as a last resort, (b) curtailments of firm load at a marginal system cost of $7,500/MWh.[77]

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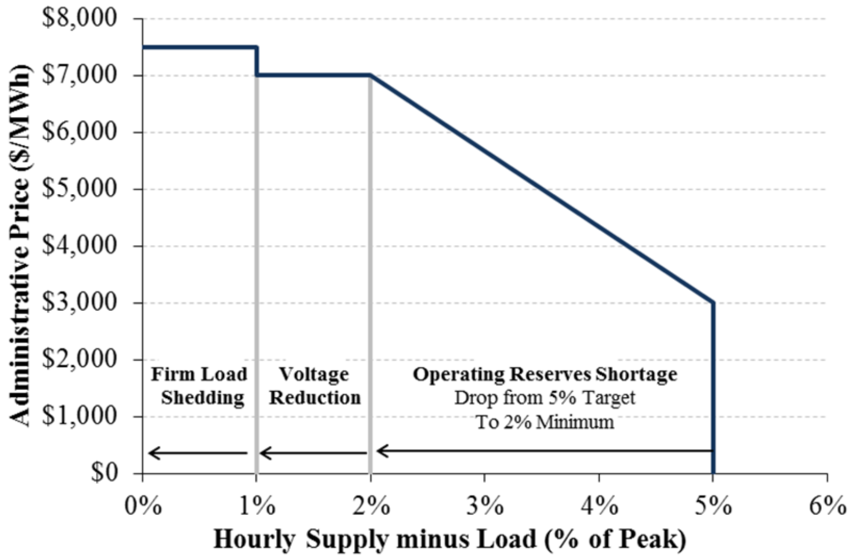
[75] Examples of RTOs who implemented administrative scarcity pricing include MISO, PJM, and CAISO.

[76] For a more comprehensive discussion of how a system operator could estimate these marginal system costs for setting an operating reserves demand curve, see Newell, *et al.* (2012). Section V.A.3.

[77] Note that load must be shed when the supply cushion drops below 1% above hourly load. This is because: (a) actual load (after voltage reduction) will be hourly load minus 1%; and (b) the 2% operating reserves requirement must still be maintained.

Figure 10
Administrative Scarcity Pricing Function



Notes:
Horizontal axis of the administrative pricing curve is calculated as a percent of peak load and does not vary with system conditions.

F. Marginal Resource Cost and Performance

To examine economic and reliability outcomes over a range of reserve margins, we must increase or decrease installed capacity of a certain resource type. In our Base Case, we assume that the marginal technology is a natural-gas-fired combustion turbine (CT). We also examine an alternative case in which the marginal technology is a gas combined-cycle (CC) plant.[78] The incremental capital and fixed costs required to build and maintain an additional resource is measured as the levelized cost of new entry (CONE), and includes both: (a) annual fixed operations and maintenance (FOM) costs; and (b) the annual levelized capital costs of constructing a new plant. Table 5 summarizes our assumed CONE and heatrates for CT and CC plants, which are approximately consistent with current PJM parameters.[79] We examine the sensitivity of our results to our assumed CONE value in Section IV.B.3.

[78] See Section III.B.3.

[79] Actual plant costs could be anywhere over a substantial range. These reported costs are within the range of CONE values we estimated for different locations within PJM on a level-nominal basis for CT and CC plants with a 2015 online date. For a more precise report of construction costs and plant performance for a specific technology, see Spees, *et al.* (2011), pp. 2–3, 18.

Table 5
Assumed Cost and Performance of New Gas CT and CC Plants

	CONE *($/kW-yr)*	Heatrate *(btu/kWh)*
Combustion Turbine	$120	10,500
Combined Cycle	$150	7,000

Notes:
Approximately consistent with current PJM parameters, see Spees, *et al.* (2011), pp. 2-3, 18.

G. BASE CASE AND ALTERNATIVE SIMULATION CASES

To explore the reliability and economic implications of varying reserve margins, system configuration, and other study assumptions, we simulate the interconnected illustrative power system for a Base Case and test the sensitivity of our results to various assumptions. We also implement a number of Change Case simulations designed to evaluate the impact of system characteristics as summarized in Table 6 below. As shown, the alternative simulations test the impacts of: (1) lowering the energy market price cap; (2) assuming a smaller system size (with or without decreasing intertie capability); (3) increasing or decreasing the availability of neighbor assistance; (4) assuming that a CC rather than a CT is the marginal technology; (5) increasing wind penetration; and (6) increasing DR penetration.

Table 6
Summary of Simulation Cases

Simulation Case	Simulation Description
Base Case	- System assumptions as defined in Section II. - Vary Study RTO margin from 7% to 17% by adding gas CTs
Lower Price Caps	
$1,000 Price Cap Case	- Impose $1,000/MWh energy price cap in Study RTO and Neighbors
$3,000 Price Cap Case	- Impose $3,000/MWh energy price cap in Study RTO and Neighbors
Smaller System Size	
40% Size Case	- Study RTO size 40% of Base Case (20,000 MW peak load)
40% Size and Transmission	- Reduce Study RTO size to 40% of Base Case (20,000 MW peak load) - Reduce interties to 40% of Base Case (4,000 MW)
Neighbor Assistance	
Long Neighbors Case	- Increase Neighbors' reserve margins from 15% to 20%
50% Transmission Case	- Reduce Study RTO interties to 50% of Base Case (5,500 MW)
Island Case	- Eliminate Study RTO interconnections with neighbors
Marginal CC Case	- Add gas CCs to increase the Study RTO reserve margin from 7% to 17%
Wind Penetration Case	- Increase wind penetration up from 5% of peak load (at a 12% Study RTO reserve margin) up to 30% of peak load
DR Penetration	
Emergency DR Penetration	- Fix Study RTO reserve margin at 15% - Vary DR penetration from 0% to 20% of peak load by displacing CTs with Emergency DR (100 hours, $2,000/MWh strike price)
Economic DR Penetration	- Fix Study RTO reserve margin at 15% - Vary DR penetration from 0% to 20% of peak load by displacing CTs with Economic DR (unlimited call hours, strike prices from $0 to cap)

III. SIMULATED RELIABILITY LEVELS AND SYSTEM COST RESULTS

In this section, we report the results of a series of economic and reliability simulations for a hypothetical RTO with realistic attributes. We do not attempt to exactly replicate any particular real-world power system, but instead evaluate base and sensitivity case simulations that are generally illustrative of the economics of resource adequacy.

We first estimate the planning reserve margin needed to achieve different physical reliability standards such as 0.1 LOLE, 2.4 LOLH, and 0.001% Normalized EUE. We then compare those results to alternative standards based on economic criteria such as cost minimization and risk exposure. Finally, we evaluate the reliability and economic impacts of making different assumptions about system conditions, resource attributes, and transmission interconnection levels.

A. BASE CASE ECONOMIC AND RELIABILITY RESULTS

We present here the primary reliability and economic results from our Base Case analysis by: (a) comparing the reserve margins needed to achieve different reliability-based resource adequacy standards; (b) estimating the planning reserve margins that would minimize total system costs on a risk-neutral basis, defined from either a cost-of-service or a societal perspective; (c) discussing the risk mitigation benefits achieved by increasing the target planning reserve margin; and (d) evaluating the sensitivity of these economic results to study assumptions.

1. Reserve Margins Needed to Achieve Physical Reliability Standards

As explained in Section I.B.2 above, resource adequacy-related system reliability increases with reserve margin.[80] As a result, the frequency of outage events decreases at higher planning reserve margins. Figure 11 shows this on an installed capacity (ICAP) basis for our Study RTO.[81] The chart documents that, for our study RTO, the 1-in-10 standard translates to a 15.2% planning reserve margin target when defined as 0.1 LOLE, using a probability-weighted average of outage events across all scenario runs.[82] The figure also shows that even under identical

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80 Recall that resource adequacy (*i.e.*, the extent to which physical supply exceeds anticipated load) accounts for only a small portion of end-use customer load-shed events, the majority of which are caused by smaller failures on the distribution system and to a lesser extent on the transmission system.

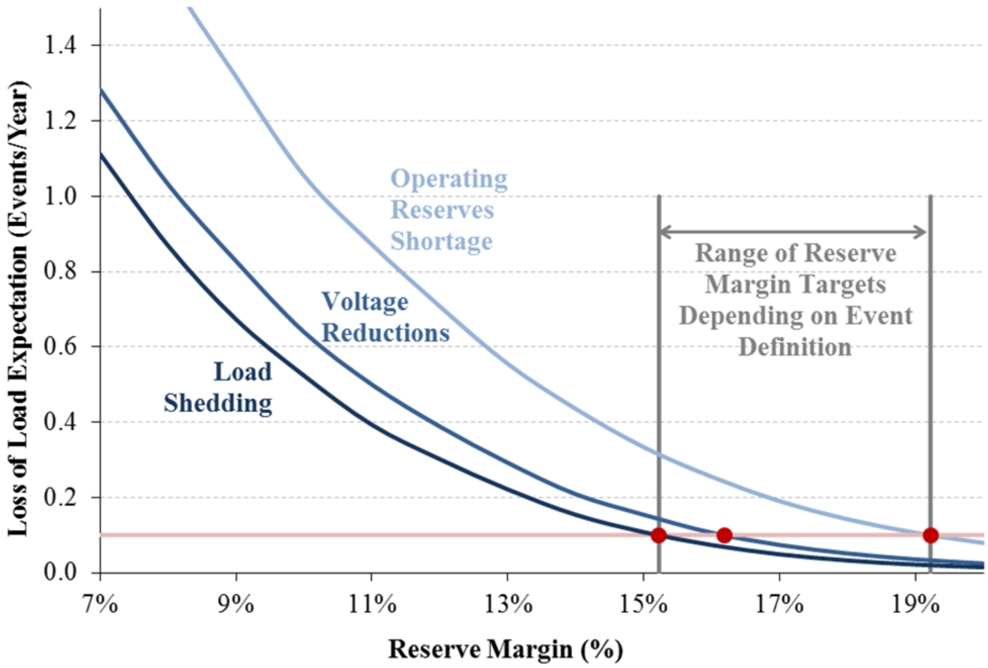
81 In this figure and the entirety of this study, we calculate the reserve margin on an ICAP basis, assuming a capacity value 100% of nameplate capacity for all resources, including both economic and reliability DR, with the exception of renewable generation, which we assign capacity value of 15% of nameplate for wind and 25% for solar. We do not assign any capacity value to voltage reductions when calculating the reserve margin (to be consistent with most others' definitions), although we do not ignore the availability of voltage reductions for avoiding load shedding.

82 Note that not all of the 9,600 runs that we simulate under each reserve margin are equally likely. We assume that any one of the 32 weather years and 50 draws on unit performance are equally likely, but the 6 different economic forecast error points are not equally likely with the more extreme over- or under-forecasts being less likely as explained in Section II.D.2 above. We account for these different likelihoods

Continued on next page

modeling and system assumptions, the target planning reserve margin ranges from 15.2% to 19.2%, depending on how "reliability events" are defined. In the remainder of this report, we treat events as contributing to LOLE only if firm load is shed, although some system operators define reliability "events" more broadly as discussed in Section I.C above. For example, the reserve margin requirement for 0.1 LOLE would be 16.2% if voltage reductions were considered reliability events or 19.2% if any depletion of operating reserves constituted an event.

Figure 11
Planning Reserve Margins for 0.1 LOLE with Different "Event" Definitions



Notes:
Study RTO in Base Case simulation results.

The target reserve margin also depends on which type of physical reliability standard we impose, even if one consistently defines reliability events as load-shed events. Figure 12 shows (from left to right) a planning reserve margin requirement of: (a) 15.2% when the 1-in-10 standard is defined as 0.1 LOLE (as it is in most U.S. regions); (b) 8.2% if the 1-in-10 standard is defined as 2.4 LOLH; or (c) 9.6% under the 0.001% Normalized EUE standard that is used in some international markets.[83]

This analysis shows that a 0.1 LOLE standard is a much more stringent reliability standard than 2.4 LOLH for the Study RTO, despite the fact that these two standards are both commonly referred to as "1 day in 10 years." The magnitude of the difference between the two standards

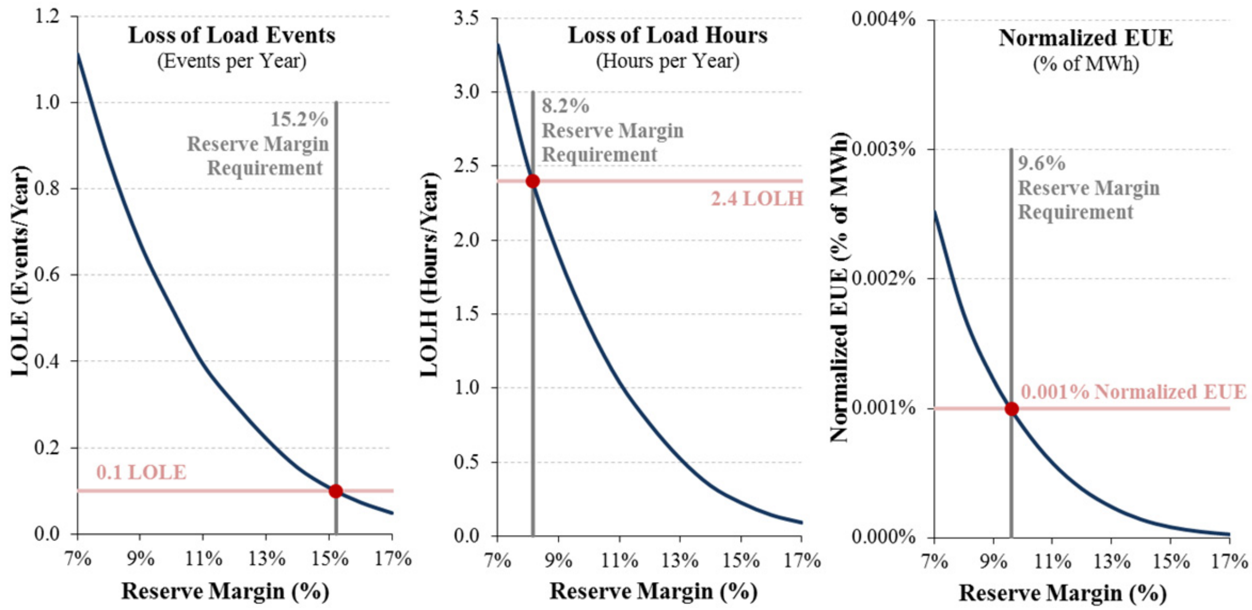
Continued from previous page

when reporting average and percentile outcomes, although for simplicity we usually refer only to "average" results rather than "probability-weighted average" results.

83 See additional discussion of these alternative reliability standards in Sections I.B.1and I.C above.

will not be the same in every system because it is driven by the average duration of the firm load shed event. For the Study RTO, the average duration of a single firm load shed event is typically only a small number of hours, which means accumulating 24 hours over ten years requires a number of individual outage events.

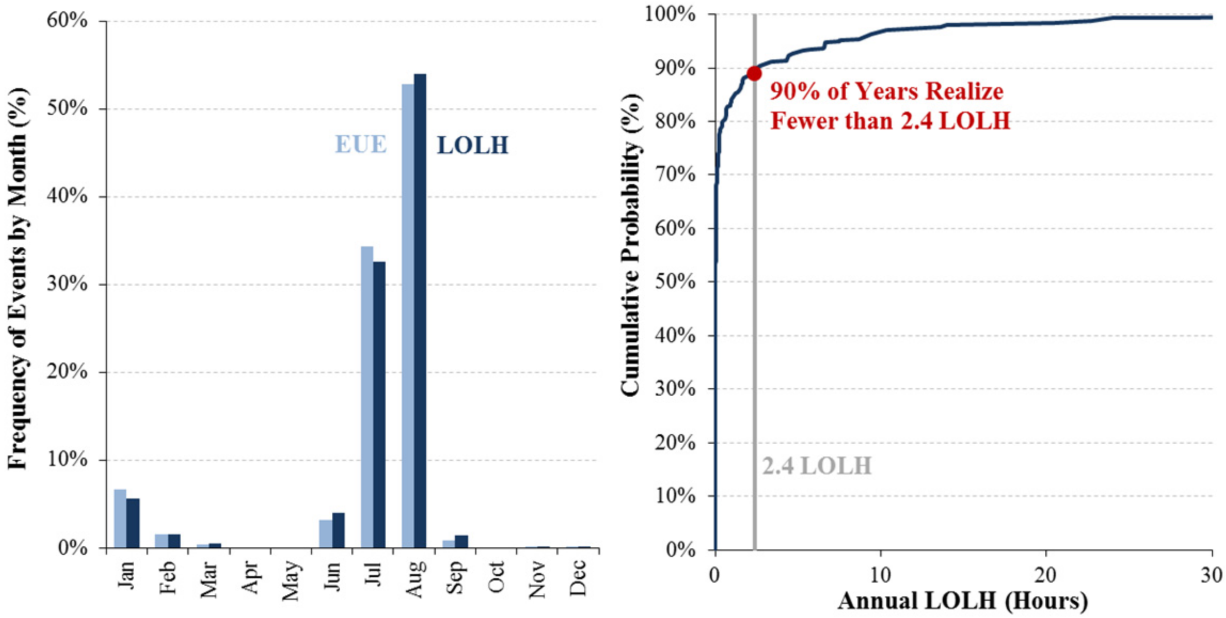
Figure 12
Planning Reserve Margins Required to Meet Different Physical Reliability Standards



Notes:
Study RTO Base Case simulation results.

The smooth and well-behaved appearance of these physical reliability metrics masks the substantial sensitivity to the underlying simulation assumptions and particularly to assumptions affecting extreme events. Although most reliability simulations consider thousands of scenarios, the value of the reliability metrics is usually driven by only a small number of extreme outage, weather, and load forecasting error scenarios, as illustrated in Figure 13. The chart shows the EUE and LOLH observed at a 10% reserve margin by month of year (on the left), and cumulatively for all 9,600 simulated years (on the right). As in all summer-peaking systems, our hypothetical RTO realizes nearly all outage events during the summer peak months. The importance of extreme events is highlighted even more by the right-hand chart, which shows that 45% of all simulated years have no outages, while the single worst simulation shows 68 load shed hours in the year. While only 10% of years exceed the 2.4 LOLH threshold, the probability-weighted average over all cases is 1.4 LOLH.

Figure 13
Distribution of Loss of Load Hours at 12% Planning Reserve Margin
Across Months (Left) and Across Simulation Years (Right)



Notes:
Distribution of realized EUE and LOLH in the Study RTO Base Case at 10% planning reserve margin.

2. Minimizing Cost from a Risk-Neutral, Cost-of-Service Perspective

As discussed in Section I.B.3 above, utilities and regulators in some regions use economic rather than reliability criteria to determine target reserve margins. Broadly speaking, these economic analyses aim to minimize total system costs by determining the "economically optimal" reserve margin. Such an economic analysis weighs the tradeoff between: (a) increasing capital and fixed costs associated with adding capacity to the system; and (b) decreasing reliability-related costs incurred during scarcity events, such as interrupting load, dispatching high-cost resources, procuring high-cost imports, and so on.

Accurately modeling or even defining some of these reliability-related costs is a challenging exercise. The exercise is further complicated by the fact that the cost-minimizing reserve margin is different depending upon the perspective from which costs are to be minimized. Some of the important questions to answer are:

- Is the objective to minimize societal costs, including all fixed and variable costs, regardless of whether those costs will be passed along to customers? Or, alternately, to minimize customer costs after evaluating how various costs will ultimately impact customer in their bills and realized outage rates?
- Should one consider only costs within the study region or also the costs imposed on external regions by relying on imports during scarcity events?

– If minimizing customer costs is the objective, is it from the perspective of a cost-of-service-regulated utility or the cost of serving customers in a competitive retail market?[84] Further, how do the costs of imports and revenues from exports affect customer costs within the Study RTO?

– Are costs to be minimized on a risk-neutral basis, which assumes that customers and regulators only care about the lowest average costs but not the proportion of costs introduced by extreme events? Or is it appropriate to assume some risk aversion and therefore ascribe an insurance value to avoiding high-cost events?

Depending on the perspective applied to a particular economic reliability study, choices implicit in each of these questions would yield a different planning reserve margin. For the purpose of our study, we first evaluate the economics of resource adequacy from a risk-neutral cost-of-service perspective. In this context, the objective is to minimize the expected cost of service within the Study RTO while ignoring any economic or reliability costs imposed on neighboring regions. We then examine the same reliability and economic questions from a societal cost perspective in the following Section III.A.3. Finally, Section III.A.4 explores how risk mitigation objectives could affect the planning reserve margin target, because higher reserve margins will substantially reduce the magnitude and likelihood of extreme events.

To estimate the risk-neutral, "economically optimal" reserve margin, we simulate realized reliability costs over a range of reserve margins as summarized in Figure 14. We vary the Study RTO planning reserve margins by adding or subtracting CTs as the marginal resource.[85] The Study RTO's total reliability-related costs for the Base Case, defined from this cost-of-service perspective, include:

Marginal Unit Carrying Costs – Fixed costs and annualized capital costs incurred by adding incremental capacity, assuming that the marginal resource is a CT with a CONE of \$120/kW-year.[86] We do not report fixed costs associated with the existing generation fleet because these costs do not vary with reserve margin.

Marginal Unit Production Costs – Production costs associated with dispatching the added new CTs. These are the incremental production costs incurred to displace higher-cost existing resources, higher-cost imports, and higher-cost emergency procedures.

[84] In a competitive retail market environment, adopting the objective of minimizing customer costs may be inappropriate in some circumstances, particularly where doing so would tacitly condone suppression of market prices. Note, however, that minimizing customer costs and minimizing societal costs are equivalent under the idealized case in which all internal and external markets are perfectly competitive, efficiently designed, and in a long-term equilibrium.

[85] We make alternative marginal resource assumptions in Section III.B.3 below, where we examine the impacts of adding or subtracting CCs instead of CTs.

[86] As explained in Section II.F above, this capital cost is within the range of level-nominal CONE values estimated for different regions in PJM for a CT with an online date in 2015, see Spees, *et al.* (2011), pp. 2-3 and 18. Section IV.B.3 below shows the sensitivity of the economic reserve margin to a range of CONE assumptions.

Net Import Costs – Total costs of purchasing imports net of any revenues from exporting power.[87] This treatment of imports and exports is consistent with how cost-of-service regulated utilities will typically evaluate net import costs.[88] It is also consistent with the Adjusted Production Costs (APC) metric commonly used within RTO systems for production cost analyses and transmission benefit-cost studies.[89] Note that this approach to tabulating import costs results in incorporating price suppression as a benefit, because displacing imports through new CTs during scarcity conditions will not only reduce the quantity of imports but will also reduce the price paid for all other imports. The price-suppression component of reduced import costs would not be considered a benefit if evaluated from a broader "societal" perspective as discussed further below.

Peaker Production Costs – Production costs associated with dispatching peaking resources that have higher operating costs than the marginal CT plants added to the system. Note that we would arrive at the same study results if we considered total system production costs, but the much larger total costs would make visual representation of the results more difficult.[90]

Emergency Generation – Emergency generation is the incremental cost associated with dispatching generating resources at very high output levels that exceed their typical economic operating range. Pushing units to generate at such high levels can impose additional wear and tear on units, and consequently impose incremental maintenance costs. We assume that all generating units can produce incremental output at their "emergency maximum" rating, which is assumed to exceed their "economic maximum" rating by 1% at a marginal cost of $500/MWh, as explained in Section II.E above.

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87 The realized price of purchasing imports and selling exports also depends on who owns the transmission rights needed to import and export power. Whoever owns the rights to send power across a particular transmission path will likely be able to capture the value of that transmission, buy power in the lower-price market, schedule the power to flow across that path, and sell into the higher-price market. For example, if exporters generally own the transmission rights, then they obtains the market price at the buyer's location (*i.e.*, the higher-cost market). Alternately, if importers generally own the transmission rights, then the importer can buy the power at the seller's location (*i.e.*, the lower-cost market). For the purpose of our simulations, we assume that importers and exporters each own 50% of transmission rights needed for import and export transactions. This means that imports and exports are transacted by the Study RTO utility at market price that reflects the average of the market prices at the source and delivery point. However, as we note further below, changing this assumption can have a substantial impact on total customer reliability costs and, thus, a significant effect on economic planning reserve margins.

88 This approach implies a number of assumptions, including that the net export revenues will be credited against the Study RTO cost of service and, thus, flow back to customers. This would not necessarily be the case if, for example, some export revenues were earned by independent power producers (IPPs) rather than a regulated utility.

89 For a summary of the APC metric and its limitations see SPP (2012a), Section 5.

90 In other words, adding CTs has a negligible impact on the dispatch profile of baseload units and so baseload-related production costs will remain unchanged across different reserve margin levels. However, baseload production costs are orders of magnitude greater than the reliability-related costs we report, making it difficult to report these results graphically. We do summarize total costs, including baseload-related costs, when comparing total customer costs in Section IV.D.2 below.

Emergency Hydro **–** Reliability costs associated with emergency hydro dispatch. The marginal system cost of dispatching these resources is difficult to quantify because it depends on the opportunity cost of not saving the resources for later emergencies as well as any societal costs associated with reduced reservoir levels. We assume emergency hydro has a marginal system cost and dispatch price of $3,000/MWh.[91]

Economic and Emergency DR **–** Load curtailment costs associated with two types of demand response resources: (1) Economic DR, which offers into the energy market in all hours at costs ranging from $100 to $1,000/MWh and which may be dispatched an unlimited number of times; and (2) Emergency DR, which does not offer into the energy market but can be dispatched a limited number of times during emergencies at a cost above $2,000/MWh. We assume that these dispatch costs reflect the payments made to these DR resources and assume that it also reflects the net cost that service interruptions impose on DR suppliers, as explained in Section II.C.4 above.

Operating Reserves Shortages **–** Reliability costs imposed by temporarily operating the system with depleted operating reserves during scarcity events. We do not attempt to calculate these costs explicitly because doing so is a complex exercise in evaluating the incremental contingency risks endured at each reserve level. Instead, we calculate these costs implicitly using the administrative "operating reserves demand curve" covering a $3,000-$7,000/MWh range of prices as discussed in Section II.E above. This administrative pricing curve is similar to the administrative scarcity pricing mechanisms recently implemented by several U.S. RTOs.[92] If such an operating reserves demand curve is designed efficiently, it will reflect the marginal system costs incurred when depleting operating reserves.

Voltage Reductions **–** System costs imposed by implementing a system-wide voltage reduction as the last resort before shedding load. These costs could include both equipment damage caused by the voltage reduction and lost economic value to end users (*e.g.*, due to motors running at a lower speed). We assume voltage reductions incur a system cost of $7,000/MWh, or just below the assumed VOLL as explained in Section II.E above.

Load Shedding **–** Service interruption costs imposed at a VOLL of $7,500/MWh for the average customer typically curtailed as explained in Section II.E above.

Figure 14 summarizes the annual averages of total Study RTO-wide reliability costs over a range of planning reserve margins. For each reserve margin level, we show the weighted-average reliability costs across all 9,600 annual simulations. At the lowest reserve margin shown in the chart, average annual reliability costs are high and are primarily driven by the high cost of imports during scarcity conditions. Other factors such as the value of lost load, DR interruption costs, and peaker dispatch costs impose relatively modest reliability costs even at low reserve margins. As planning reserve margins are increased, total reliability costs drop more quickly than the increases in capital and production cost associated with adding CTs. As a result, total

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[91] See additional discussion in Section II.E above.

[92] For additional discussion of how administrative demand curves for operating reserves are used to set prices and reflect marginal system costs during scarcity events, see Newell, *et al.* (2012), Section V.A.2.

costs drop as the reserve margin increases until the (risk-neutral) "optimal" quantity of capacity has been added at a planning reserve margin of 10.3%. After crossing this minimum cost point, the capital costs of adding more capacity exceed the benefits from reduced reliability costs, and so total costs increase.

Note that at the 10.3% reserve margin, the Study RTO has a planning reserve margin that is substantially below the 15% reserve margin we assumed in all of the neighboring regions. This means that the neighbors are providing substantial assistance to the Study RTO, allowing it to reduce both costs and reliability events. This also means that the Study RTO is relying on its neighbors in a way that increases those regions' reliability-related costs. In other words, the Study RTO is able to minimize its costs at the 10.3% reserve margin only as long as the neighbors are indirectly "subsidizing" resource adequacy for the Study RTO. If the neighbors were to reduce their own reserve margins below 15%, then the Study RTO's cost-minimizing reserve margin would increase.[93]

Another prominent feature of the chart is that net import costs represent a large portion of total reliability-related costs and these costs drop more quickly than other costs. This is because adding capacity within the Study RTO not only allows one to displace higher-cost imports with lower-cost internal supply, but also reduces the market price at which all imports must be purchased. In other words, we incorporate price suppression as a "benefit" from this cost-of-service perspective, even though it is not a benefit from a broader societal perspective as discussed further in the following section. Further, this benefit is tied to the assumption that external regions would maintain a 15% planning reserve margin. The benefit consequently would not be sustained if the external regions' generation investment decreased.[94]

Additionally, the size of net import costs is greatly influenced by our assumption about who owns the transmission rights. We assume that customers in the Study RTO own the rights to half of all import and export capability on each of its interties, meaning that they will earn the price differential between the importing and exporting markets in all hours. However, as a general rule any importer, exporter, power marketer, or transmission owner may own some portion of these transmission rights. If we make alternative assumptions about transmission ownership, the optimal cost-of-service reserve margin changes from 10.3% in the base case, down to 8.3% with an importer-owns assumption and up to 12.3% with an exporter-owns assumption.[95]

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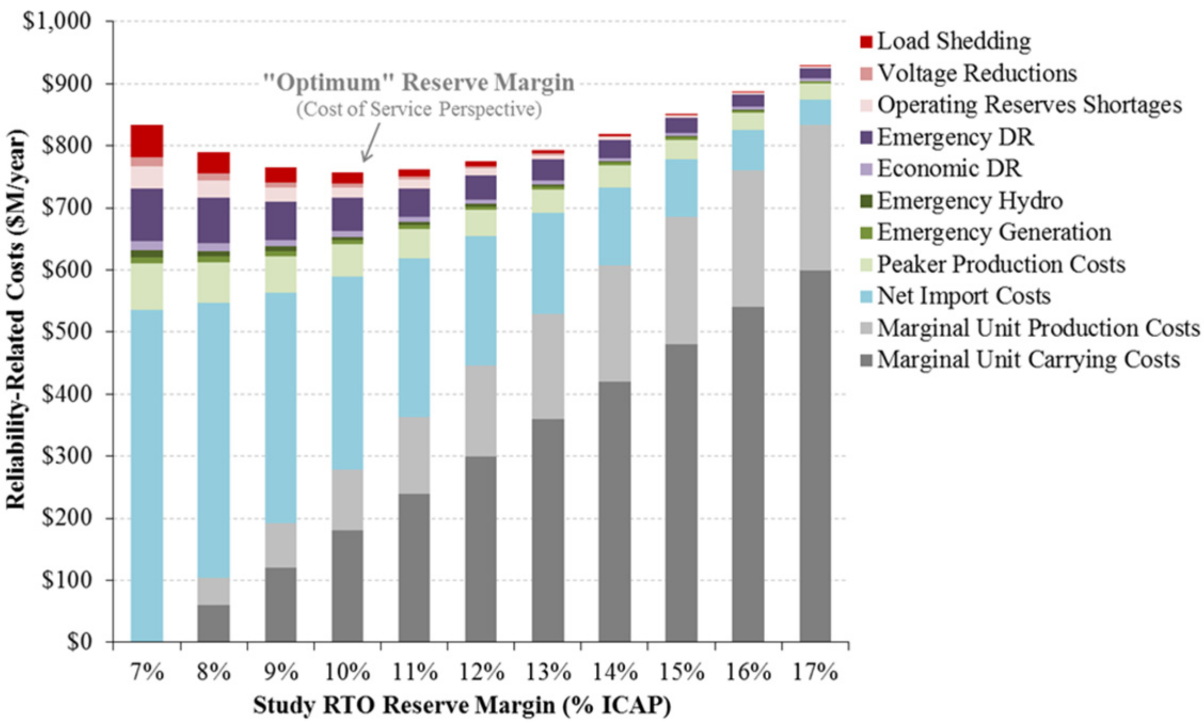
93 See additional discussion of these impacts in Sections III.A.3 and III.B.2.

94 Note that increasing the Study RTO reserve margin will reduce prices and reliability events in neighboring regions, both of which may result in the external region reducing its own reserve margin.

95 Note that as a net importer, the Study RTO achieves greater "price suppression" benefits from building capacity under the exporter-owns assumption than under the importer-owns assumption (because in the importer-owns case the price suppression "benefit" is offset by a similarly-sized offsetting price suppression "cost" imposed by the reduced value of its transmission rights). This is why the importer-owns assumption results in a lower optimal reserve margin while the exporter-owns assumption results in a higher optimal reserve margin.

The total cost curve shown in Figure 14 has a shape similar to what we have observed in many different systems in our own studies as well as in other value of service studies.[96] The curve is relatively flat near the minimum average cost point, indicating that expected total costs do not vary substantially between reserve margins of 8% to 14%. However, as we discuss further below, the lower end of that minimum cost range is associated with much more uncertainty in realized annual reliability costs and a much larger number of severe, high-cost reliability events. While the weighted average of annual costs for the Study RTO is very similar over the 8% to 14% planning reserve margin range, the higher reserve margin would avoid a majority of the high-impact, high-cost events that would be experienced at the 8% planning reserve margin. In other words, at the 14% reserve margin, a greater proportion of total annual costs are associated with added CTs (which have little uncertainty), and a smaller proportion of the average annual costs are from low-probability but high-cost reliability events.

Figure 14
Study RTO Reliability Costs as a Function of Study RTO Reserve Margin
(Risk-Neutral, Cost-of-Service Perspective)



Notes:

Study RTO reliability-related costs for Base Case simulations.

Expected annual costs are minimized from a cost-of-service perspective at a planning reserve margin of 10.3%.

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96 For example, see Keane, *et al.* (1992) pp. 824, 826; Poland (1988), p.21; Munasinghe (1988), pp. 5-7 and 12-13; and Carden, Pfeifenberger, and Wintermantel (2011).

3. Minimizing Cost from a Risk-Neutral, Societal Perspective

In this section, we estimate the risk-neutral, cost-minimizing reserve margin from an overall societal rather than a cost-of-service perspective. Under the cost-of-service perspective, we took a narrow geographic view and evaluated end-user costs for only the Study RTO without considering any reliability-related costs imposed on neighboring regions. In this section, we evaluate total reliability-related costs incurred across all four regions, regardless of whether those costs are incurred within the Study RTO or one of the neighboring regions. While any one individual utility may rationally apply the objective of minimizing customer costs from a single-system perspective, the broader societal perspective is more applicable in many contexts. For example, this broader geographic view of societal costs is more relevant for a large RTO or jurisdictional authority whose responsibility may span many utility service areas or several states.

We simulate reliability costs over the same range of reserve margins examined in the previous section, but estimate total system costs across all four study regions. The following cost components are identical from both the societal and cost-of-service perspectives as discussed above:

- Marginal Unit Carrying Costs
- Marginal Unit Production Costs
- Peaker Production Costs
- Emergency Generation Costs
- Emergency Hydro Dispatch Costs
- Economic and Emergency DR Interruption Costs
- Operating Reserves Shortage Costs
- Voltage Reduction Costs
- Load Shed Costs

However, the remaining components differ from a societal perspective. While the cost-of-service perspective assesses the costs of all imports (exports) at the purchase (or sales) price, this accounting does not apply to a multi-regional societal cost perspective. We thus removed the Net Import Cost category and added two cost categories to account for reliability costs incurred in neighboring regions. Note, however, that in this study marginal generation capital and production costs are only incurred in the Study RTO; no generation is being added in the neighboring regions. The reliability costs incurred in neighboring regions are calculated in the same way that they are calculated for the Study RTO, but are reported separately as:

Neighbors' Emergency Event Costs – Neighbors' emergency event costs include most of the cost categories evaluated, including: emergency generation, emergency hydro, economic DR, emergency DR, operating reserves shortages, voltage reductions, and load shedding. We assume that the neighboring regions have the same reliability procedures and emergency costs as the Study RTO. Note that adding additional capacity within the Study RTO will reduce the frequency of each of these types of emergency events not only internally, but also externally.

Neighbors' CT and Peaker Production Costs – Neighbors' CT and peaker production costs mirror the Peaker Production Cost category of the Study RTO.[97] Adding capacity in the Study RTO will reduce these costs in neighboring regions by allowing the Neighbor to import more during some occasions when high-cost peakers would otherwise need to be dispatched.

Figure 15 summarizes these total system reliability costs from a societal perspective over a range of reserve margins based on all 9,600 annual simulations for each reserve margin level, with reserve margins reported for both the Study RTO as well as the combined four-system region. As in the previous section, these costs represent the weighted average across all simulated scenarios. The total represents the combined total of the four-system societal costs on a risk-neutral basis. All of the colored slices are identical in size and meaning as those reported in the previous cost-of-service section, except for the two blue slices representing cost changes in the neighboring regions. In other words, we have eliminated net import costs (light blue slice) from Figure 14 above, but added the neighboring regions' reliability costs (light and medium blue slices) to Figure 15 below. In addition, we report cost results along the x-axis not only as a function of the planning reserve margin in the Study RTO, but also as a function of the reserve margin for the combined four-system region.[98]

As shown in Figure 15, from a total societal cost perspective, the optimal target reserve margin in the Study RTO (assuming the neighboring regions maintain a 15% reserve margin) is reduced from 10.3% under the cost-of-service perspective to 7.9% under a societal perspective. The primary reason for this difference is that, while customers within the Study RTO can benefit from import price reductions by increasing their own internal reserve margin, such price reductions are not a benefit from a societal-cost perspective. From a study RTO cost-of-service perspective, increasing the Study-RTO reserve margin to 10.3% is cost-effective because it reduces the net cost of imported power, both by reducing the amount of energy imported and by reducing the price paid for imported power. However, additional capacity above the 7.9% reserve margin is not beneficial from a societal-cost perspective because the Study-RTO benefit is outweighed by the combined impact on neighboring RTOs and the additional capital expenditure.[99]

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97 With the exception that this category for the external regions also includes costs from units that happen to have the exact same price as the marginal CT. Sometimes the marginal unit will displace imports from higher-cost resources, but sometimes it will also displace imports from equally-priced CTs, which is why we include these costs as well for the neighboring regions.

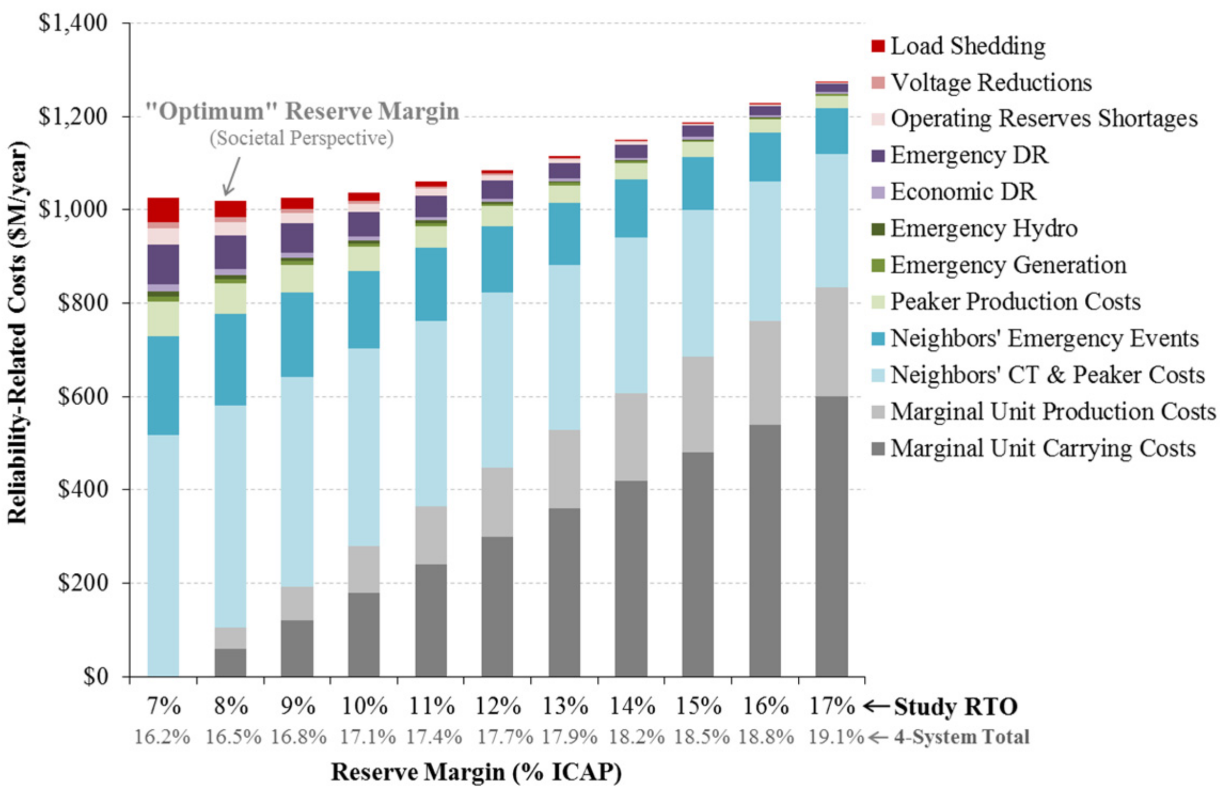
98 Note that we add capacity only inside the Study RTO and not in any of the Outside Regions. The total reserve margin for the four systems combined changes only because capacity is being added in the Study RTO. The installed capacity in the neighboring regions is held constant at the original 15% reserve margin.

99 In other words, "optimizing" the system from a Study RTO cost-of-service perspective aims to provide maximum benefit to customers (excluding suppliers impacts) in the Study RTO (excluding impacts on neighboring regions), which would generally introduce some deadweight loss relative to the "optimum" solution that one would achieve if planning across multiple systems from a societal perspective without regard to which supplier, customer, or region benefits most.

Figure 15 and Table 7 also show that the 7.9% Study RTO reserve margin, combined with 15% Neighbor reserve margins, is equivalent to an overall four-system reserve margin of: (a) 13.0% if measured against the non-coincident peak load, and (b) 16.5% if measured against the coincident peak load as reported in the figure. This 16.5% reserve margin is higher than the individual systems' reserve margins because the neighbors' 15% reserve margin and the Study RTO's 7.9% target reserve margin are all reported relative to their individual systems' non-coincident peak loads, the sum of which is higher than the combined four-system coincident peak load.

Because the Study RTO's optimal internal reserve margin is much lower than the neighbors' assumed 15% reserve margins, this means that the Study RTO is relying more heavily on the neighboring regions during scarcity conditions, and that the neighboring regions are "supporting" resource adequacy in the Study RTO through the combination of their 15% reserve margin and intertie capabilities.

Figure 15
Reliability Costs in all Regions as a Function of Study RTO Reserve Margin
(Risk-Neutral, Societal Perspective)



Notes:

Reliability-related costs for all four regions in the Base Case scenario.

Societal costs are minimized at reserve margins of 7.9% in the Study RTO (measured against Study RTO non-coincident peak load) or 16.5% across all four regions (measured against four-system coincident peak).

Table 7
Coincident and Non-Coincident Reserve Margin Accounting
At the Societally Optimal Reserve Margin

	Generation	Peak Load		Reserve Margin	
		Non-Coincident	Coincident	Non-Coincident	Coincident
	(MW)	*(MW)*	*(MW)*	*(%)*	*(%)*
Study RTO	53,950	50,000	48,605	7.9%	n/a
Neighbor 1	69,000	60,000	58,686	15%	n/a
Neighbor 2	46,000	40,000	38,604	15%	n/a
Neighbor 3	34,500	30,000	28,773	15%	n/a
Total	**203,450**	**180,000**	**174,668**	**13.0%**	**16.5%**

A planning effort designed to optimize the location and size of resource additions across all four interconnected regions would likely result in decreasing the neighbors' reserve margins while increasing the Study RTO reserve margin. However, the target reserve margins for the four regions that result in the lowest cost for the entire system will depend on a wide variety of factors. For example, some of the factors determining the cost effectiveness of increasing the reserve margin in a particular region would include: (a) whether a region is an import-constrained area like the Los Angeles Basin, New York City, or Eastern PJM; (b) whether the sub-region is highly dependent on limited-dispatch DR during peak periods, which would make adding CTs more valuable; (c) whether two sub-regions are well-interconnected with large load diversity, allowing both sub-regions to gain substantial resource adequacy benefits from the same capacity resource; and (d) whether adding new CTs in one region would allow for the retirement of aging resources with high fixed costs.

4. Risk Mitigation Benefit of Increasing Reserve Margins

The economic results shown in the previous sections assume risk neutrality with respect to the uncertainty and volatility of reliability-related costs. This allows us to compare total costs at different reserve margins in Figure 14 and Figure 15 simply as the probability-weighted average of annual reliability costs for all 9,600 simulated scenarios. However, there is substantial volatility around the average level of possible reliability cost outcomes. Most simulated years will have only very modest reliability costs, while a small number of years have very high reliability costs. These high-cost outcomes account for the majority of the weighted average annual costs shown as the individual bars in Figure 14 and Figure 15.

Figure 16 summarizes this risk exposure by comparing the weighted average costs for different reserve margins (shown as the individual bars in Figure 14, from a cost-of-service perspective) to annual costs under the most costly possible outcomes, represented by the 85th, 90th, and 95th percentile of annual reliability costs across all 9,600 simulated scenarios. The figure shows that the majority of all reliability-related costs are concentrated in the most expensive 15% of all simulation runs for each planning reserve margin. In other words, for 15% of possible annual outcomes, the annual reliability costs are at or above the 85th percentile line shown in the chart. This means that, while total average costs change by a relatively modest amount over a range of planning reserve margins, differences in planning reserve margins have a much larger impact on the uncertainty in reliability costs and the likelihood of high-cost outcomes than can be encountered in any particular year.

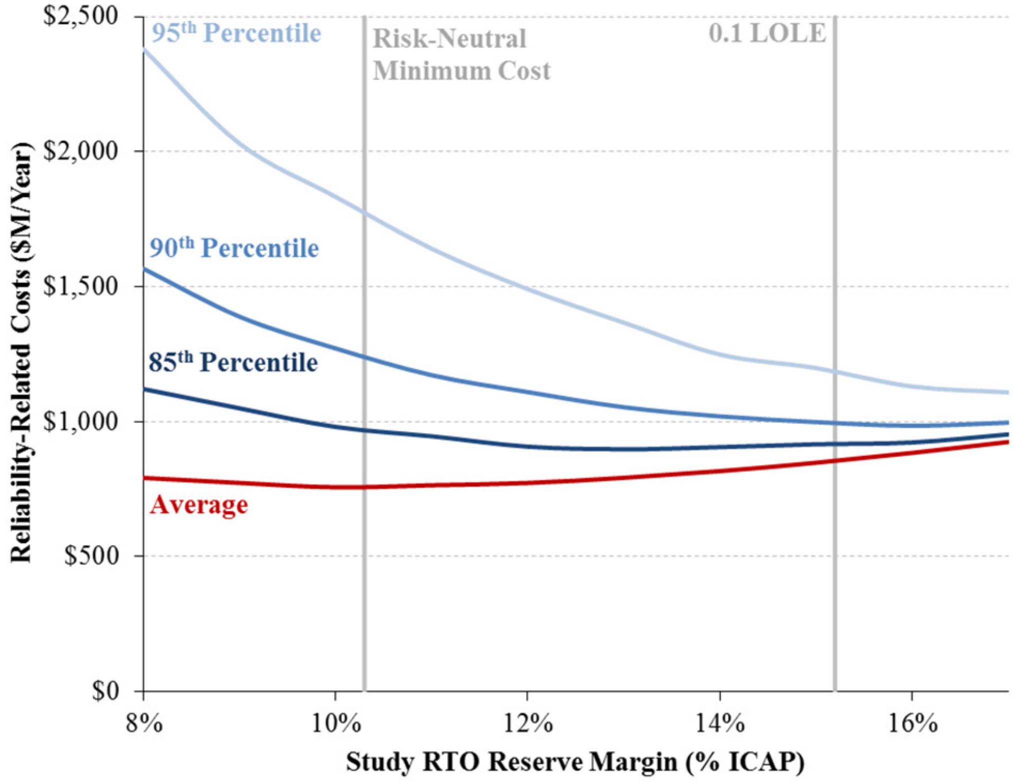
Considering the much higher cost uncertainty exposure at lower reserve margins, many planners and policy makers may wish to set planning reserve margins above the risk-neutral economic optimum. In our sample system, even a several percentage point increase in the target reserve margin would only slightly increase the average annual costs, but substantially reduce the likelihood of experiencing very high-cost events. However, without evaluating the magnitude of the increase in average costs and decrease in extreme event costs, policy makers would not be in a position to determine whether a higher reserve margin is justified by its risk mitigation benefits.

For example, our simulations show that the risk-neutral optimal planning reserve margin is 10.3% for the Study RTO from a cost-of-service perspective. In comparison, the planning reserve margin would need to be 15.2% to achieve the 0.1 LOLE standard. As Figure 14 and Figure 16 show, the increase in average annual costs required to achieve the 15.2% planning reserve margin is relatively modest at approximately $90 million per year. However Figure 16 also shows that this would reduce the annual costs incurred once in a decade (*i.e.*, costs above the 90th percentile) by at least $270 million per year, and the costs incurred once in 20 years (*i.e.*, costs above the 95th percentile) by at least $630 million per year. In other words: (a) a risk-neutral policy maker would not increase reserve margins above the 10.3% risk-neutral optimum because, by definition, the expected costs would exceed expected benefits; (b) a somewhat risk-averse policy maker might increase reserve margins slightly but possibly not enough to meet 0.1 LOLE at 15.2% reserve margin where the costs exceed the benefits by a ratio of approximately three-to-one; and (c) a highly risk-averse policy maker might wish to meet or even exceed the 15.2% reserve margin needed to meet 0.1 LOLE.

In evaluating these cost and risk tradeoffs, policy makers should also consider that suppliers and customers will be able to hedge a significant portion of these risks through forward contracting. As we discuss further in Section IV, a large portion of the risk of encountering the high-cost outcomes illustrated in Figure 16 is related to weather uncertainty. Some of that risk exposure can likely be hedged cost effectively, including through seasonal forward contracts. For example, many suppliers and load serving entities (LSEs) in ERCOT hedge most of their summer price spike exposure through forward contracts on a seasonal basis.[100]

[100] See additional discussion and documentation in Section IV.A.3 below.

Figure 16
Uncertainty Distribution of Annual Reliability-Related Costs
(Cost-of-Service Perspective)



Notes:
Study RTO reliability-related costs for Base Case from a cost-of-service perspective.

5. Sensitivity to Forecast Error and Forward Planning Period

As explained in Section II.D.2 above, uncertainty in economic growth and the consequential economic load forecasting uncertainty are key planning considerations. Uncertainty caused by economic forecasting error increases with the forward period. This is unlike annual weather-related uncertainty, which is generally assumed to be constant over time. Adopting a longer forward planning period therefore will result in higher load forecast uncertainty and, if resource additions cannot be modified on a shorter-term basis, a higher likelihood of reliability and scarcity events. This means that increasing the forward period in resource adequacy studies will also increase the reserve margin necessary to achieve any given reliability standard.

In our Base Case analysis, we adopt a four-year forward planning period based on a conservative estimate of the approximate lead time needed to develop new resources.[101] The lead time for

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[101] Note that although the entire development timeline for most new plants is greater than four years, much of that development work, including siting and permitting, can be done without making major irreversible financial commitments. This means that the time needed for actual plant construction is most relevant when the resource investment decision is truly locked in. Developing and constructing a natural gas CC or CT takes approximately 3.25 and 2.8 years respectively, see Spees, *et al.* (2011), Appendices A.3 and B.3.

developing new resources is also the reason that PJM and ISO-NE's capacity markets rely on a three-year forward period. In non-RTO markets and the integrated planning processes subject to state regulation, at least a portion of all planning decisions are often made on a schedule that looks more than three years forward.[102] Note, however, that most systems also have substantial flexibility to adjust their total resource portfolio on a shorter-term basis, including even on a one-year forward basis. For example, there is substantial capability to adjust DR commitments, revise import-export balance, adjust retirement or retrofit decisions, delay or accelerate plant development efforts, and invest in plant upgrades on a shorter-term basis.

We examine the implications of revising the forward planning period on the reserve margin standard and total system costs by adopting alternative economic forecast error assumptions consistent with different forward periods as documented in Section II.D.2 above. Increasing the forward period increases the economic load forecast error, which consequently increases the planning reserve margin whether the reserve margin is reliability-based as shown in Figure 17, or economically-based as shown in Figure 18.

As Figure 17 shows, reducing the forward planning period from four years to one year would reduce the 0.1 LOLE-based planning reserve margin by 1.7%, from 15.2% to 13.5%. This would, of course, require that sufficient short-term resources exist that could be mobilized on a 12-month basis should economic growth prove greater than anticipated.[103] As noted, such short-term resources might include DR resources (assuming the market is not fully saturated), upgrades to existing plants (or new plants under construction), reactivations of mothballed plants, an increase in net import commitments, or accelerating in-service dates of new plants under development.

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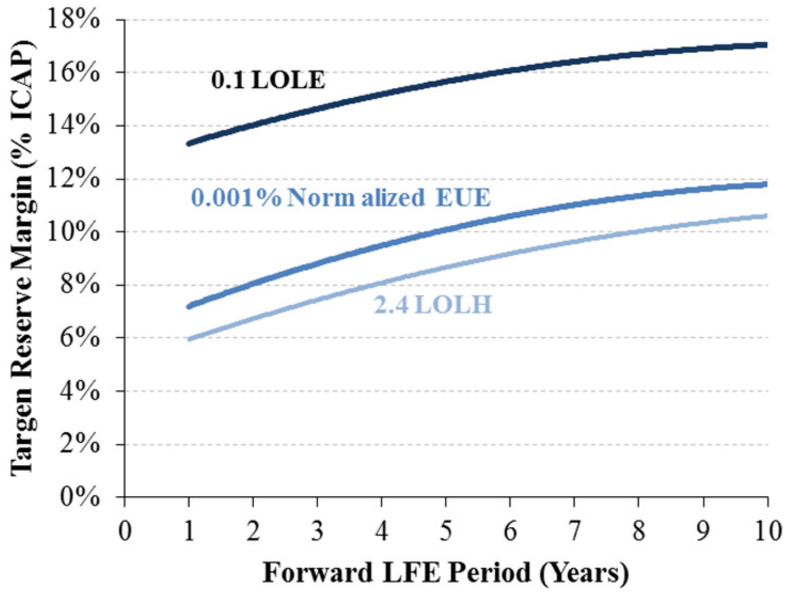
[102] For example, see the discussion of the Long-Term Resource Planning processes implemented by California's investor owned utilities under the oversight of the state commission in Pfeifenberger, *et al.* (2012).

[103] For example, assume that most resource investment decisions (*e.g.*, for existing generation) were made on a longer term basis but the final 5% of resources were not procured until one year prior to delivery. However, the actual amount of incremental resources needed on a one-year forward basis may only be 3% or as high as 7% if economic growth were higher or lower than expected in prior planning exercises.

Figure 17
Reliability-Based Resource Adequacy Standard vs. Forward Planning Period

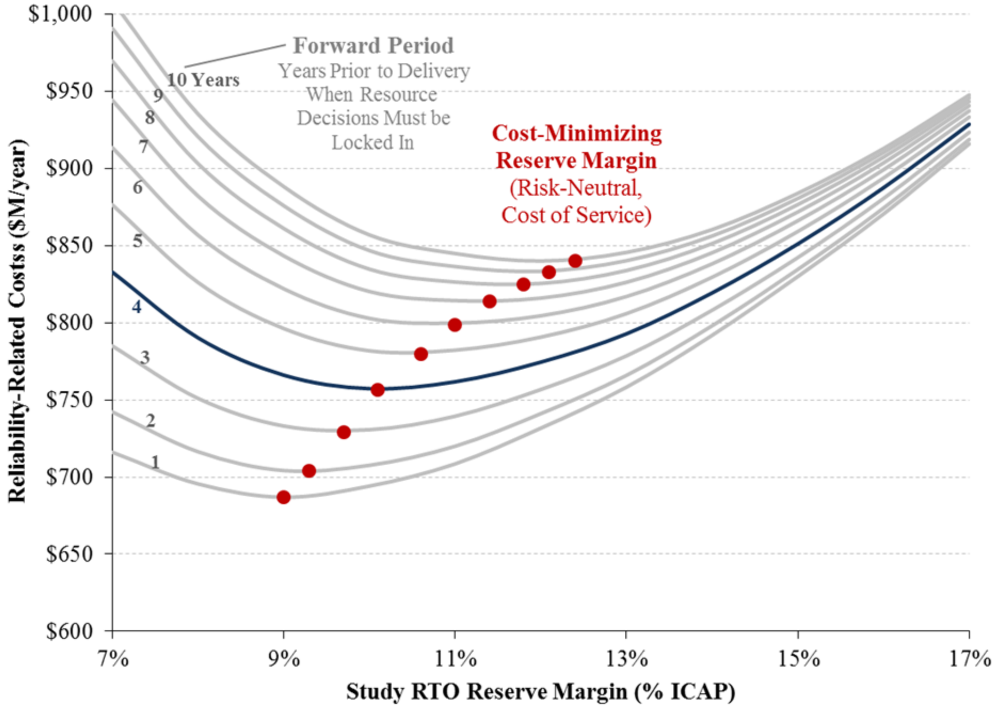


Notes:
Study RTO reliability-based reserve margin vs. forward period.
Load forecast error varies with planning period, see Section II.D.2.

Figure 18 similarly shows that increasing the forward period will increase the economically optimal planning reserve margin. The chart shows total reliability-related costs from a risk-neutral cost-of-service perspective (as in Section III.A.2 above) under different forward periods. The Base Case assumption of a four-year forward period is shown as a blue line while the gray lines show costs ranging from a one-year to a ten-year forward planning period. Total costs increase substantially with a higher forward period because there is a much greater risk of high-impact events associated with under-forecasting economic load growth (and greater capital costs required to build sufficient capacity to avoid such events). However, if sufficient short-term resources exist to allow for a reduction of the forward planning period from four years to one year, then the risk-neutral optimal reserve margin would decrease by 1.3%, from 10.3% to 9.0%.

This suggests that if a region has a reasonably high amount of additional short lead-time DR resources, it may be beneficial to adopt a forward procurement approach similar to that used in PJM, where most resources are procured three years forward but the remaining 2.5% of resources are procured on 2-year, 1-year, and short-term basis. This could reduce total procurement costs by reducing the procured reserve margin more often than not. However, it also increases the risk of under-procurement in a high load growth situation. If substantially more than 2.5% of resources are needed on a short-term basis, there may not be enough supply available to meet the need; or the only available resources may be high-cost DR that is not cost-competitive under ordinary circumstances. We further examine the implications of high DR penetration in Sections III.C and IV.C below.

Figure 18
"Optimal" Reserve Margin as a Function of Forward-Planning Period
(Risk-neutral, Cost-of-Service Perspective)



Notes:
Study RTO reliability-related costs for Base Case from a cost-of-service perspective.
Load forecast error varies with planning period as described in Section II.D.2.

B. IMPACT OF SYSTEM CHARACTERISTICS

This section of our report summarizes the extent to which target reserve margins are affected by system characteristics. The specific sensitivities we explore are: (1) system size (40% Size Case and 40% Size and Transmission Case); (2) intertie size and neighbor assistance (Long Neighbors Case, 50% Transmission Case, and Island Case); (3) using CCs rather than CTs as the marginal capacity resource (Marginal CC Case); and (4) higher penetration levels of intermittent renewable resources (High Wind Penetration Case).

1. Impact of System Size

We first examine the implications of system size under two alternative cases, in which: (1) we reduce the RTO Study Region to 40% of its Base Case size (from a peak load of 50,000 MW to 20,000 MW); and (2) we reduce the system to 40% of its Base Case size and also reduce all interconnections with neighboring regions to 40% of their Base Case size. In both of these cases we maintain the same resource mix, unit sizes, and external region characteristics as in the Base Case.

Table 8 summarizes the target reserve margin results for these two change cases compared to the Base Case. The 40% Size Case shows that both the 1-in-10-based and the economic target reserve margins decrease for the Study RTO. The 0.1 LOLE target drops only slightly from

15.2% in the Base Case to 14.8% in the 40% Size Case, while the other reliability-based targets drop more substantially from 8.2% to less than 6% under the 2.4 LOLH standard and from 9.6% to 7.5% under the 0.001% Normalized EUE standard. The risk-neutral, cost-minimizing reserve margin decreases even further, from 10.3% (cost-of-service perspective) and 7.9% (societal perspective) to less than 6% under both perspectives. The reason for the lower planning reserve margin targets is that the smaller Study RTO is able to rely more heavily on neighbor assistance. This is the case because the smaller RTO requires a fewer imports during reliability events. In other words, the neighbors are able to provide proportionally greater assistance to the smaller Study RTO.

If we also proportionally reduce the size of the interconnections with neighboring regions, then some of these neighbor-assistance benefits are lost to the smaller Study RTO as also shown in Table 8. The target reserve margin based on 0.1 LOLE is reduced from 15.2% to only 15.1% (compared to 14.8% when maintaining the Base Case size of the interconnections) while the 0.001% Normalized EUE and 2.4 LOLH standards only increase to 8.1% and 6.9% respectively. The economic target reserve margins still remain at less 6% (outside our study range). The combination of these alternative simulation cases shows that: (a) a small system can rely more readily on neighbor assistance to reduce its planning reserve margin; and (b) the value of neighbor assistance is substantially greater for a well-interconnected small system.

Table 8
Study RTO Reserve Margin Targets with a Smaller System Size

Simulation	Reliability-Based			Risk-Neutral, Cost-Minimizing	
	0.1 LOLE	2.4 LOLH	0.001% Normalized EUE	Cost-of-Service Perspective	Societal Perspective
Base Case (50,000 MW)	15.2%	8.2%	9.6%	10.3%	7.9%
40% RTO Size (20,000 MW)	14.8%	<6%	7.5%	<6%	<6%
40% Size w/ 40% Intertie	15.1%	6.9%	8.1%	<6%	<6%

These lower target reserve margins for the smaller system may initially appear counter-intuitive or inconsistent with general industry experience. Historically, many small utilities maintained reserve margins in excess of 20% and were able to reduce these margins over time by merging, interconnecting with neighbors, developing reserve-sharing agreements, or joining larger RTO systems. This apparent disconnect with our results is primarily driven by the fact that traditional utilities were much smaller and more "islanded" than even the "small" Study RTO (20,000 MW) in our simulations. Traditionally, many utilities may have relied less on interties for reliability because many: (a) were not as well-interconnected with their neighbors; (b) would have faced more difficulty in obtaining neighbor assistance during peak events, particularly prior to the implementation of reserve sharing agreements and liquid wholesale power markets; and (c) may have been conservative in assessing the reliability value of their interties in the absence of firm power purchase commitments.

In addition, the high reserve margin targets of many small utilities are driven by a single-largest-contingency analysis. For example, a small utility's reliability standard may stipulate that the utility is able to meet peak load even if the single largest generator or transmission line were to fail. In a large system, such a contingency criterion typically does not affect the planning reserve margin. However, for a small utility serving only a few thousand MW of load, contingency considerations can substantially increase planning reserve requirements. We did not conduct any contingency analysis in this study, but even in the "small" 20,000 MW Study RTO Case, such contingencies are unlikely to affect planning reserve margins. Nevertheless, if we had treated the small system as a substantially more islanded region, then it would better reflect the historical experience of smaller utilities and would result a higher reserve margin requirement.

2. Intertie Size and Neighbor Assistance

Strong interties with neighboring regions provide both economic and physical reliability value during peaking conditions. Load and generation diversity mean that the most extreme scarcity conditions are unlikely to occur at the same time in neighboring markets. This inter-regional diversity means that the Study RTO will often be able to rely on emergency imports to avoid load shedding and improve system reliability. Interties create economic benefits as well, for example, by allowing the Study RTO to purchase imports from external CTs rather than dispatching higher-cost internal DR resources.

We examine the value of interties and neighbor assistance for a number of cases, with the planning reserve margin results summarized in Table 9. The results are shown in order of increasing availability of neighbor assistance, including: (1) a "Long Neighbors Case" where the neighbors' reserve margins are increased to 20% compared to 15% in the Base Case (and intertie capability equal to the Base Case); (2) the Base Case, where the neighbors have 15% reserve margins and the Study RTO has 11,000 MW of intertie capacity); (3) a "50% Transmission Case," with interties at 50% relative to the Base Case (and neighbors' reserve margins at 15%); and (4) an "Island Case" with no interties.

The table shows that the interties offer substantial benefits from both a physical reliability and economic perspective. Maintaining the 0.1 LOLE requires increasing the internal reserve margin from 13.0%% in the Long Neighbors Case, to 15.2% in the Base Case, 15.8% in the 50% Transmission Case, and 18.5% in the Island Case. In terms of the economic benefits of neighbor assistance and interties, these cases show that the cost-minimizing reserve margin (from a risk-neutral cost-of-service perspective) increases from 8% in the Long Neighbors Case, to 10.3% in the Base Case, 12.3% in the 50% Transmission Case, and 16% in the Island Case.

Table 9
Study RTO Reserve Margin Targets with Varying Availability of Neighbor Assistance

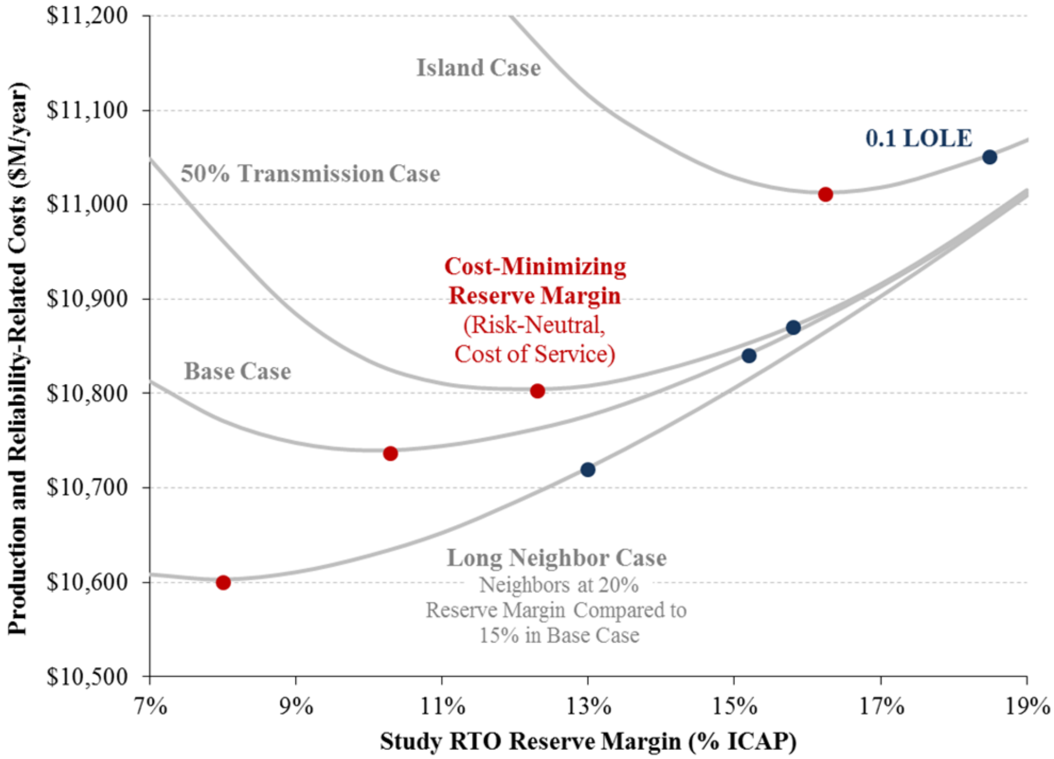
Simulation	Reliability-Based			Risk-Neutral, Cost-Minimizing	
	0.1 LOLE	2.4 LOLH	0.001% Normalized EUE	Cost-of-Service Perspective	Societal Perspective
Long Neighbors Case	13.0%	<6%	7.0%	8.0%	<6%
Base Case	15.2%	8.2%	9.6%	10.3%	7.9%
50% Transmission Case	15.8%	9.8%	10.0%	12.3%	10.5%
Island Case	18.5%	16.5%	15.8%	16.5%	16.5%

That interties provide substantial economic value is also shown in Figure 19, which displays total system production and reliability-related costs from a risk-neutral, cost-of-service perspective for different planning reserve margins and interconnection assumption. Not counting the costs of the interconnections themselves, the figure shows that system costs increase as interconnections decrease for a given level of reserve margin. For example, at a 14% planning reserve margin for the Study RTO, reducing interties by 50% increases average annual costs by $21 million per year relative to the Base Case. Totally eliminating the interties increases average annual costs by $262 million per year relative to the Base Case. However, as shown in Figure 19, these economic costs can also be reduced substantially by increasing the planning reserve margin. Reducing interties at a particular reserve margin increases system costs because it reduces the ability of the Study RTO to import lower-cost resources. This generally reduces costs at any time when the system is importing, which is particularly valuable during scarcity and emergency events. The Long Neighbor Case also illustrates that assumptions about reserve margins maintained in external systems has a substantial impact on the Study RTO's target reserve margin.

Maintaining a 0.1 LOLE also imposes greater costs in more isolated systems, because the Study Region not only loses the opportunity of lower-cost imports, but it also incurs the large capital costs associated with having to maintain a higher reserve margin. Maintaining a 0.1 LOLE in the 50% Transmission Case incurs an additional $43 million of average annual costs compared to the Base Case, while the Islanded system incurs $219 million in additional average annual costs. As the differences in reserve margin and total costs for the economic and LOLE-based reserve margin targets shown in Figure 19 demonstrate, the cost savings from increased interconnections and neighbor assistance are more substantial if the reserve margin is determined economically rather than with LOLE targets. A full study of the economic value of a particular intertie upgrade would also consider the cost of the expanded interties relative to these economic benefits, in addition to other reliability and operational benefits that the intertie might provide.

Figure 19 also shows that the value of interties increases when neighboring regions have excess capacity, because the Study RTO can rely more heavily on the neighboring regions for low-cost imports under normal as well as scarcity conditions. For example, increasing external reserve margins from 15% to 20% allows the Study RTO to decrease its internal reserve margin from 15.2% to 13.0% while maintaining 0.1 LOLE. However, it is important to note that adding external capacity is not as valuable as adding internal capacity, from either a cost or reliability perspective. In fact, increasing external capacity by 6,500 MW across the three external regions reduces the Study RTO's internal reliability requirement by only 1,100 MW. This is because external resources can only be imported if: (1) interties are sufficiently sized; (2) the interties are not derated; and (3) external regions are not simultaneously experiencing scarcity or emergency peak load conditions. The capacity value of external resources would increase if they were committed to the Study RTO on a firm basis (with firm import rights), which would mean that the Study RTO would have first rights to call them.

Figure 19
Total System Costs vs. Reserve Margin with Varying Intertie Assumptions



Note:
The vertical scale is much greater than in Figure 14 and Figure 18 above, which plot the same cost data in a different way. The magnitude of the change in system costs in the Base Case is identical for all charts, but this figure adds a baseline of total Study RTO production costs to allow the comparison of total system costs across the different cases.

The reduction in Study RTO reserve margins enabled by the interties relative to the Island case, is sometimes referred to as the "tie benefit" or "capacity benefit of interties."[104] The magnitude of these intertie benefits is estimated probabilistically as the likely quantity of energy that will be available for non-firm import from neighbors during scarcity or emergency conditions. Such non-firm imports that contribute to intertie benefits are different from, and in addition to, firm imports that are committed to the Study RTO.

The most obvious approach for modeling resources in neighboring regions might be to include all projected capacity resources, including surplus capacity. The surplus capacity would increase the estimated tie benefits and reduce the Study RTO's target reserve margin. The problem with this approach is that it will not represent a long-term stable resource adequacy target because Study RTO target reserve margins would fluctuate with changes in the external regions' reserve margins (*e.g.*, as a result of plant retirements that reduce surplus capacity). Further, the study RTO may have insufficient information to accurately project the likely quantity of resources available in the external system. Because of these challenges, ISO-NE recently abandoned this approach, opting instead to model external markets "at criterion," regardless of any actual

[104] For example, see PJM (2011).

excess.[105] This more conservative "at criterion" assumption is standard among most RTOs, primarily because the Study RTO can be fairly certain that external regions will meet their own planning reserve margin targets but cannot be totally certain that an external system's existing surplus would be maintained. The "at criterion" approach also results in a more stable internal reserve margin target. While the Study RTO may still benefit from the external regions' surplus capacity through lower-cost imports and improved reliability, changing amounts of surplus would not affect the Study RTO's planning reserve margin.

A final, more complex question relates to how much of an RTO's intertie capability should be left uncommitted or even set aside as the capacity benefit margin.[106] This is one of the key questions currently being addressed at the MISO-PJM seam in the FERC cross-border capacity deliverability proceeding.[107] Under the Point-to-Point transmission rights model used across most of North America, intertie capability is broken into two components: (1) transmission capability available to support long-term firm transmission rights that are needed for a generator to sell firm capacity across market interties (*e.g.*, from MISO to PJM); and (2) transmission set aside as CBM and awarded only on a short-term basis for non-firm energy sales. Only the uncommitted portion of the interties, including any portion that is specifically set aside as CBM, would contribute to probabilistically estimated tie benefits.[108] Firm import commitments are generally treated similarly to internal resources for determining target reserve margins.[109]

There are also a number of factors to consider in determining what portion of intertie capability to set aside for CBM. As explained by MISO and its market monitor, reducing CBM would increase the transmission that could be awarded for firm exports.[110] This would likely reduce PJM's capacity costs by allowing more MISO resources to sell capacity into PJM. On the other hand, as PJM explains, reducing CBM would reduce the realized intertie benefits and thereby increase PJM's planning reserve margin. Ultimately, determining the optimal quantity of uncommitted transmission (*e.g.*, by setting it aside as CBM) is an economic question that requires balancing the tradeoff between these factors.

3. Combined Cycle Plants as the Marginal Technology

Another study assumption is the type of marginal resource that is added in our simulations to increase the Study RTO planning reserve margin. In the Base Case, we add CTs as the marginal resource. While this is consistent with the use of CTs as the standard peaking resource, a mix of peaking, intermediate, and baseload resources is typically added under real-world conditions and in regulated resource planning efforts. The most economic type of resource to build depends on the composition of the existing fleet, the forecast load profile, projected fuel prices, and other

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105 For a more comprehensive discussion of tie benefits questions within ISO-NE, see FERC (2012), p. 2.

106 For a detailed description of NERC standards relating to CBM, see NERC (2008).

107 Under FERC Docket AD12-16-000.

108 For example, see PJM's calculation of the capacity benefit of ties based on the CBM portion of its interties, PJM (2011).

109 Note that in our modeling we effectively treat all intertie capability as CBM.

110 See MISO (2012b).

factors.[111] We test the sensitivity of our results to the assumed marginal technology under a case in which we add CCs rather than CTs to increase reserve margins.[112]

As shown in Table 10, the physical reliability implications of adding CCs and CTs are essentially identical because these technologies have similar outage characteristics. Using CCs as the marginal resource results in 15.2% and 15.3% reserve margin targets under the 0.1 LOLE standard. The small differences in CT and CC outage characteristics are not large enough to make a substantial impact on physical reliability metrics. This would generally be the expected result from adding different types of thermal generation resources that have similar outage characteristics.[113]

Table 10
Reserve Margin Targets with CC and CTs as the Marginal Resource

Simulation	Reliability-Based			Risk-Neutral, Cost-Minimizing	
	0.1 LOLE	2.4 LOLH	0.001% Normalized EUE	Cost-of-Service Perspective	Societal Perspective
Base Case (Marginal CT)	15.2%	8.2%	9.6%	10.3%	7.9%
Marginal CC Case	15.3%	8.3%	9.8%	10.1%	7.7%

Coincidentally, the economic target reserve margins between the CC and CT cases are also quite similar, but slightly lower in the CC case. This result will not hold true under all circumstances since the economic consequences of adding different types of technologies may be vary considerably. The fact that it is true in our simulations consequently cannot be generalized.

Importantly, comparing the economic reserve margin targets does *not* help to determine whether it would be more beneficial to add CCs or CTs. Comparing the net system benefits achieved by adding two different types of resources requires comparing the total system costs under each case. This is illustrated in Figure 20 below. This figure shows total production and reliability

111 See a more comprehensive discussion of optimal resource mix conflicts in Pfeifenberger, *et al.* (2009), Section III.A.

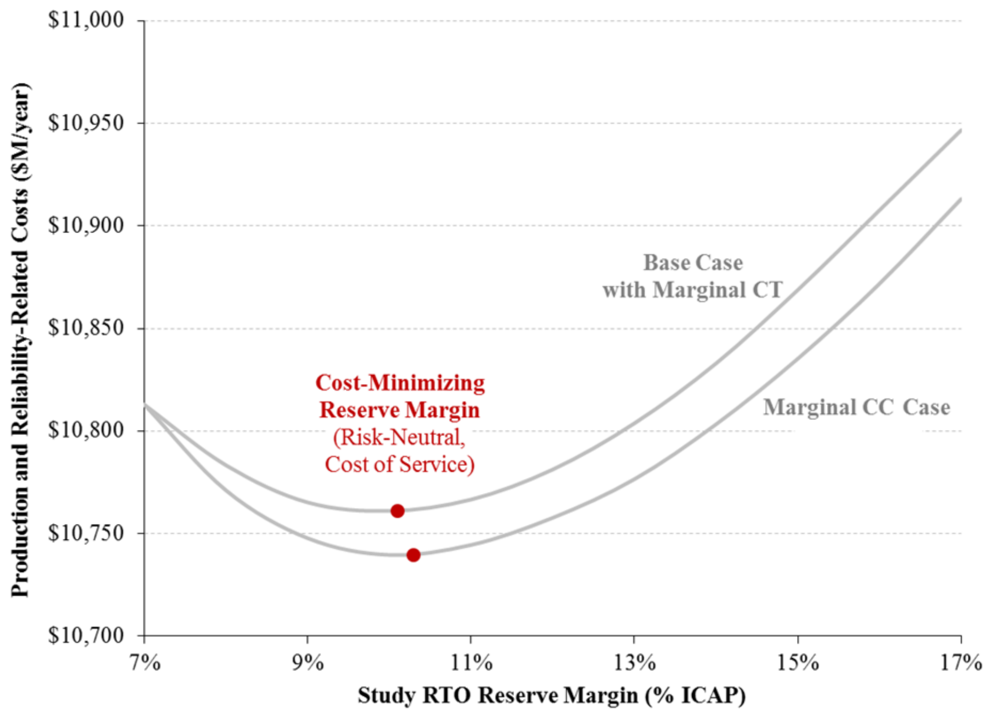
112 More generally, a thorough system planning effort could evaluate many types of resources to determine which is the most economic. Alternately, in a deregulated market-based environment, merchant suppliers would determine which type of resource to build by forecasting the profitability of each type of potential investment. Under certain, idealized conditions the system planning and market-based approaches would both result in the same type of resource being added as discussed further in Section IV.A.1.

113 We assume that CCs have a very slightly higher forced outage rate causing the reliability-based reserve margin targets to increase by a small amount of approximately 0.1% in the Marginal CC case. Conducting a modeling exercise at a higher level of granularity would be required to evaluate additional nuances regarding the reliability impacts of different types of thermal generation resources. For example, even though resources may have the same overall forced outage rates, there may be systems in which it would be relevant to examine the reliability implications of: (a) a large number of natural gas plants that are interconnected to the same pipeline that could expose the region to shortages caused by pipeline outages or other fuel supply constraints; (b) resources that do or do not have backup diesel fuel capability that would protect against many fuel-related outages; and (c) systems with high wind penetration or other contingency risks where fast-response CTs would provide additional reliability and operational value.

costs in the Study RTO from a risk-neutral, cost-of-service perspective for both CCs and CTs as the marginal resource. The figure shows that all-in fixed and variable costs drop faster when adding CCs than when adding CTs if starting with the same resource mix at the 7% reserve margin. This is because the greater production cost savings associated with adding CCs outweighs that technology's greater capital costs. In other words, even though the economic reserve margin targets are similar, it is more beneficial to add CCs than CTs because it will achieve greater system costs savings. The vertical difference between the red dots in the chart shows that the lowest average annual cost for CCs is $21 million per year below that of CTs.

However, this incremental cost advantage of CCs declines as more CCs are added, which is why the two cost curves are more parallel at higher reserve margins. At some point, the capital and operating cost tradeoff between the two technologies will equalize, at which point it will be optimal to add a mix of the two resource types.[114] `

Figure 20
Study RTO Total Production and Reliability-Related Costs with Marginal CC or CT
(Risk-Neutral, Cost of Service Perspective)



Note:
The vertical scale is much greater than in Figure 14 and Figure 18 above, which plot the same cost data in a different way. The magnitude of the change in system costs in the Base Case is identical for all charts, but this figure adds a baseline of total Study RTO production costs to allow the comparison of total system costs across the different cases.

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114 We have not attempted to identify the optimal quantity of additional CCs before the two types of resources become equally valuable. Identifying this tradeoff point would require a slightly different analysis in which we would: (1) test the incremental cost savings after adding one CC vs. one CT; and then (2) if the CC provides more value, we would keep that asset in the mix and then test the value of adding one more CC vs. one more CT.

4. Intermittent Renewable Resource Penetration

Intermittent renewable resources such as wind and solar have a resource adequacy value significantly below their nameplate capacity because they typically cannot generate at their full capacity during peak load conditions. Because high load conditions also often correspond with low wind speeds, wind turbines' resource adequacy value generally is even below the resource's average annual capacity factor. On the other hand, a solar resource's capacity value is usually higher than its average annual capacity factor because solar output typically is more correlated with peak-load conditions. Recognizing these factors, most RTOs assign intermittent resources a capacity value based on average output during peak load hours.[115] When we calculate planning reserve margins throughout this study, we assign a nominal 15% capacity value to wind generators and 25% to solar resources.

The actual resource adequacy value of intermittent resources will depend on a number of factors and increase with: (1) the degree of correlation between load and the intermittent resource's output profile; and (2) the study region's penetration of dispatch-limited resources and storage because renewable generation during near-peak conditions will allow storage and dispatch-limited resources to generate more during peak conditions.

A more precise estimate of the intermittent resources' resource adequacy value can be calculated based on Effective Load Carrying Capability (ELCC) as currently implemented in MISO.[116] Broadly, the objective of using ELCC is to assign a capacity value to each resource type that makes them interchangeable from a resource adequacy and planning reserve margin perspective.[117] While there are various approaches to calculating ELCC, our approach is to: (a) add a small quantity of gas CTs and determine the resulting reduction in LOLE; and (b) remove the gas CTs to restore the system to its starting configuration, then add intermittent wind resources until the system LOLE is reduced by the same amount as was achieved by adding the CT. Note that this LOLE-based approach is most appropriate for a system with an LOLE-based resource adequacy

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115 For example, PJM assigns intermittent resources a capacity value equal to the capacity factor during summer peak periods over the previous three years, or a generic value of 13% or 38% for new wind and solar resources respectively. See PJM (2010). For a wider survey of RTO practices for assigning wind resources' capacity value, see Milligan and Porter (2005).

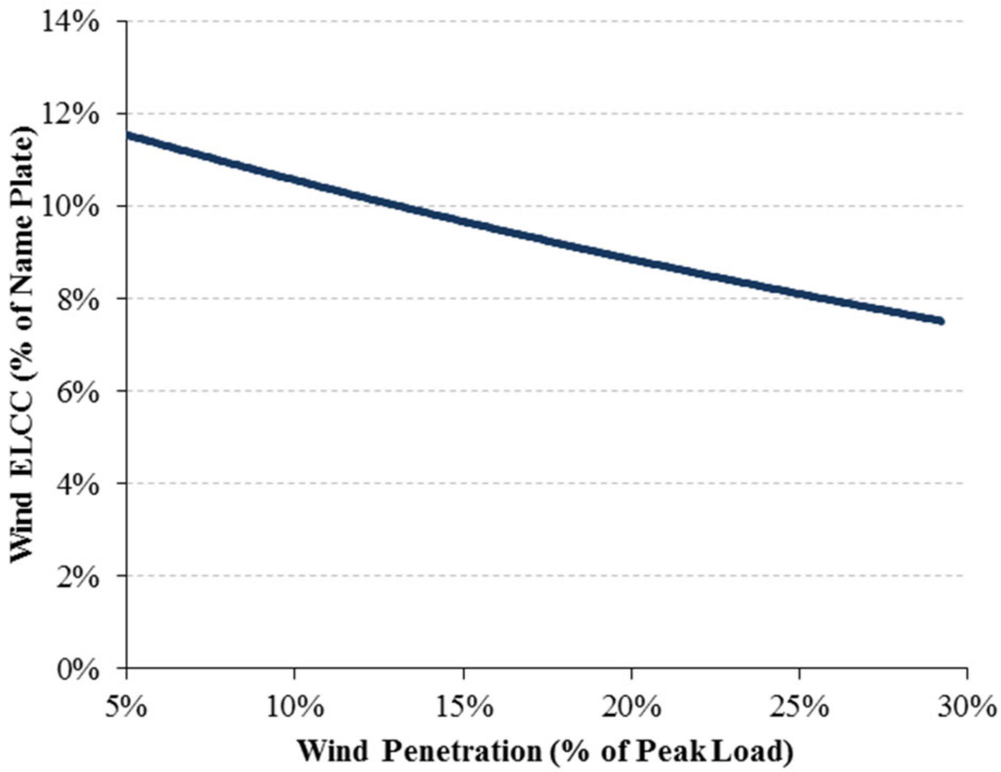
116 MISO conducts an ELCC study each year to determine the capacity value that will be assigned to all wind resources, currently set to 13.3% of nameplate, see MISO (2012a). For additional discussion of approaches to calculating ELCC, see Milligan (1997); Wiser and Bolinger (2005); Kahn (2004).

117 To date, ELCC calculations only consider the interchangeability from a physical reliability perspective in terms of reducing LOLE, LOLH, or EUE. It does not, and we do not here, attempt to ensure interchangeability from an economic perspective, which is inherently difficult because much of the economic value of a zero-marginal cost resource (like wind generation) is its energy value during off-peak conditions that do not materially relate to resource adequacy. Developing an economic comparison between wind and thermal resources would require one to either: (a) arbitrarily determine which component of energy value would be compared (*i.e.*, above some peaking cost threshold) to calculate ELCC; or else, (b) would simply compare the total economic value from energy and resource adequacy contributions, which is most relevant comparison for IRP purposes, but is not conceptually similar to ELCC.

standard. Slightly different approaches would be needed in systems with LOLH or EUE-based standards or those that account for resources in UCAP rather than ICAP terms.

We use this approach to calculate the ELCC of wind generation at varying wind penetration levels as shown in Figure 21 for the Study RTO. The figure shows that ELCC drops as wind penetration increases because the system is then more vulnerable to correlated low-wind conditions during peak load events. The figure shows that wind ELCC is only 12% at the 5% penetration level and drops all the way to 8% at the 30% penetration level. This indicates that the 15% capacity value that we assign to wind is high relative to its reliability contribution.[118] Note, however, that our relatively low ELCC results are driven by relatively poor wind profiles that correspond to the weather and load profiles of the study region. The average annual capacity factor for wind generators in the Study RTO is approximately 31%, but the output during peak load conditions is much lower.

Figure 21
Wind Generator's Effective Load Carrying Capability vs. Penetration



Notes:
Wind ELCC calculated as for the Base Case simulation, with 0.1% solar penetration.
Wind penetration expressed as wind nameplate capacity as percent of summer peak load.
Study RTO reserve margin is 12% at 5% wind penetration and increases as wind increases.

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118 Note that the Base Case and all the other simulation cases incorporate 3.9% renewable penetration, expressed as a percent of peak load (3.8% wind, 0.1% solar).

C. Displacing Generation with Demand Response

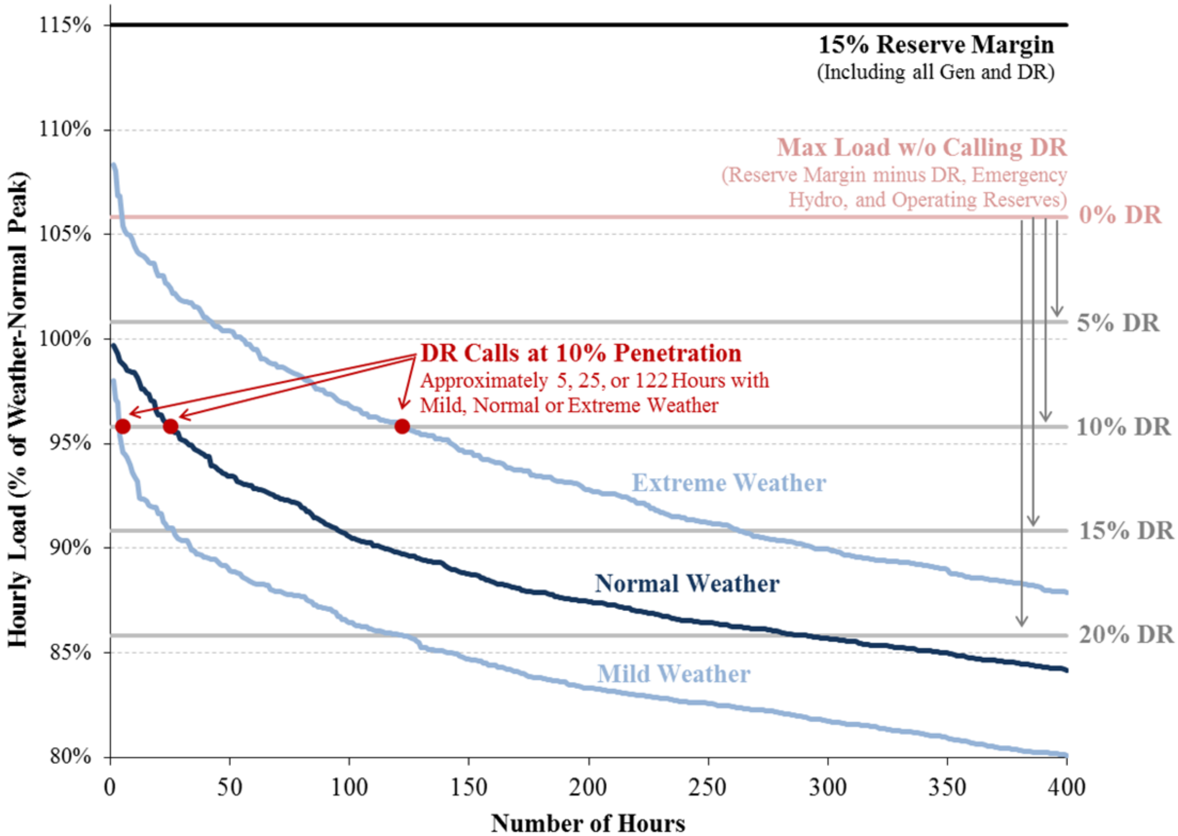
As explained in Section II.C.4 above, an important set of questions for resource adequacy in the coming years relates to the reliability and economic implications of increasing quantities of demand response. Evaluating the implications of increased DR penetration requires an approach that differs from that of using CTs or CCs as a marginal resource. When evaluating high demand response penetration, the most important questions are less related to the implications of choosing a different reserve margin but, rather, related to the implications of relying more heavily on DR as a substitute for traditional generation at a given planning reserve margin.

For this reason, we evaluate the consequences of higher demand response penetration at a fixed 15% planning reserve margin, but substitute CTs with DR resources at higher penetration levels. We evaluate this in two series of scenarios: (a) substituting CTs with emergency DR that is call-limited, at DR penetration levels of 0%, 5%, 10%, 15%, and 20%; and (b) substituting CTs with economic DR that is not call-limited but rather dispatched based on bid price at the same range of DR penetration levels. For emergency DR, we also test the impacts of varying the dispatch limit. In the following sections we discuss: (1) the reliability implications of relying more heavily on emergency DR; (2) the economic implications of higher emergency DR penetration; and (3) the economic implications of higher economic DR penetration.

1. Reliability Value of Emergency Demand Response

In this section we evaluate how the assumed 100-hour dispatch limit reduces the resource adequacy value of Emergency DR resources, particularly at higher penetration rates. The impact of a particular call-hour limit can be understood by considering the load duration curve for the top 10% to 15% of hours as shown in Figure 22. The chart shows the 400 highest-load hours in the weather-normalized year, a mild-weather year, and a high-load year. The horizontal lines show the maximum load that can be supported solely with traditional generation resources at various levels of DR penetration. As the DR level increases from 0% up to 20% of peak load, the quantity of installed generation decreases and the maximum load that can be supported without DR calls decreases.

Figure 22
Approximate Emergency DR Dispatch Hours at Varying DR Penetration Levels



Notes:

The chart is indicative of the expected quantity of DR calls but is imprecise because it does not account for the (generally offsetting) effects of generation outages, import availability, or load forecast error. See also Figure 23, which accounts for all of these factors.

The chart shows that, even without considering the impact of economic uncertainty, at a 10% DR penetration level the 100-hour dispatch limit of Emergency DR resources would be exceeded in extreme weather years. As the red dots on the chart show at 10% penetration, Emergency DR resources would be need to be dispatched approximately 5, 50, or 122 hours under mild, normal, or extreme weather respectively. At 15% DR penetration, the 100-hour dispatch limit would be exceeded even under normal weather, and with 20% DR penetration the 100-hour limit would be exceeded even with mild weather. In other words, at DR penetration levels of more than 5%, the resource adequacy value of adding more dispatch-limited DR will deteriorate rapidly unless the call limits are increased substantially.

Most regions have historically been able to rely on Emergency DR with similar or lower call-hour limitations because: (a) DR penetration levels have not exceeded approximately 5–7% in most regions; and (b) many regions across North America have enjoyed surplus generation conditions with reserve margins greater than 20%, or well above their reserve margin targets.[119] We simulate regions at their target planning reserve margins and with higher DR penetration

[119] See IRC (2009), p. 26, and NERC (2011a).

levels, which consequently requires DR to be dispatched more frequently than has been the industry experience in recent years.

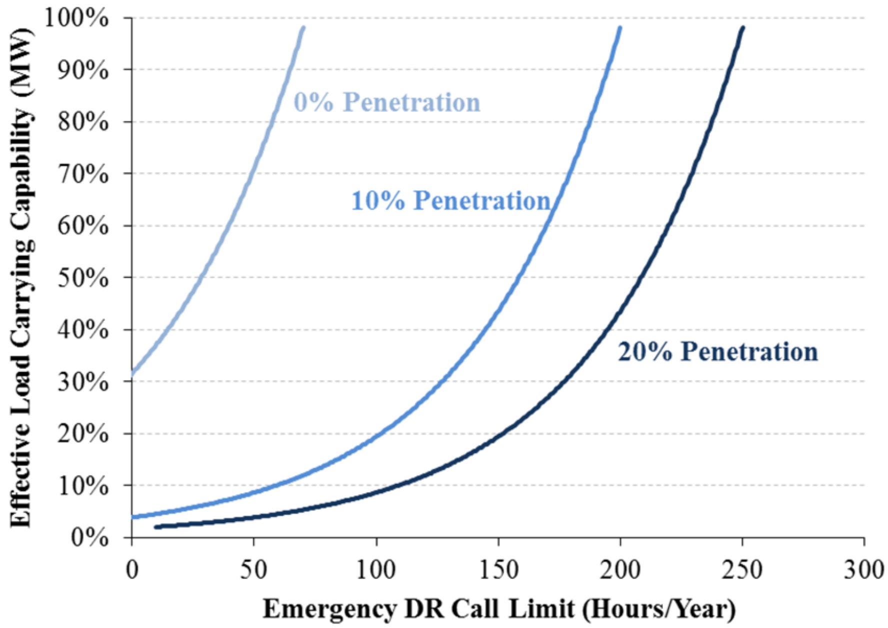
Figure 23 shows the effective load carrying capability (ELCC) of Emergency DR resources. The ELCC of Emergency DR increases with the dispatch price and decreases at higher DR penetration levels. We calculate ELCC as in Section III.B.4 above by determining the quantity of Emergency DR that would have to be added to achieve the same reduction in LOLE as adding a fully-dispatchable traditional CT. The chart shows that even at a 0% penetration level, DR with a dispatch limit of only 10 hours per year has a capacity value only approximately 30% of an equally-sized CT. This is because, even with very low penetration levels, the 10-hour dispatch limit would be exceeded significantly under outcomes with high economic growth or very hot weather.

Under the Base Case assumption with a 100-hour call limit, Emergency DR has an ELCC of approximately 100% at the 0% penetration level, 18% at 10% penetration, and only 8% at 20% penetration. The figure also shows that to maintain 100% ELCC, the call limit would have to be increased to 190 hours at 10% penetration and 250 hours at 20% penetration.

These results also show that, as long as DR penetration levels are low, a system operator does not necessarily need to consider the risk of exceeding dispatch hour limits. However, at higher penetration levels, reliability can only be maintained at criterion if: (1) Emergency DR resources are awarded a lower capacity value for the purposes of calculating their contribution to the reserve margin; or (2) Emergency DR resources are required to increase their call-hour limit. Some regions may implement a combination of these options as DR penetration increases in order to accommodate different types of DR that have more or less callability, as has been done in PJM. PJM now allows DR resources to participate either as dispatch-limited DR that may earn lower capacity payments or unlimited DR that can earn full capacity payments.[120]

[120] For a discussion of these multiple DR products, see Pfeifenberger, *et al.* (2011a), Section VI.C.1.

Figure 23
Emergency DR's Effective Load Carrying Capability
(Varying DR Penetration and Call Hours)



Notes:

Study RTO reserve margin fixed at 15% with CTs displaced by increasing DR.

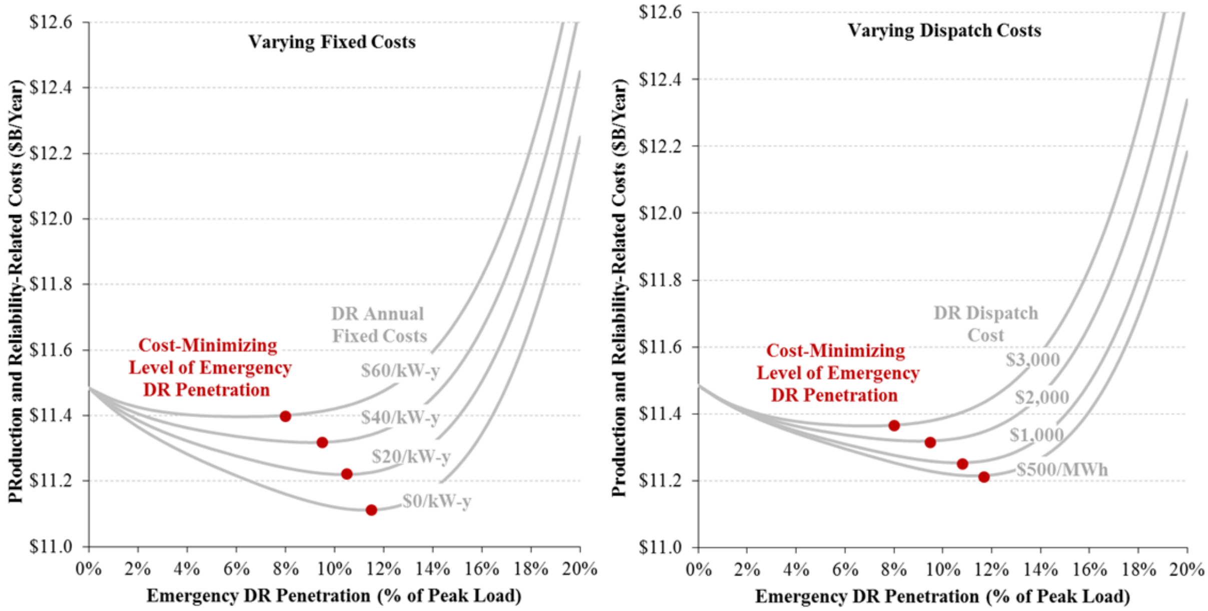
ELCC of 25% indicates that 4 MW of DR would be needed to achieve the same reduction in LOLE as adding 1 MW of CTs.

2. Cost-Minimizing Level of Emergency Demand Response Penetration

At higher penetration levels, the incremental value of adding Emergency DR drops from a cost perspective, as well as from a reliability perspective. We illustrate this in Figure 24, which shows Study RTO production and reliability-related costs as the Emergency DR penetration level increases (and installed generation levels consequently decrease). The chart shows total costs under: (a) varying *fixed-cost* assumptions for DR ranging from $0/kW-year to $60/kW-year (on the left); and (b) DR *dispatch-cost* assumptions ranging from $500/MWh to $3,000/MWh (on the right).

As shown in Figure 24, beginning at 0% DR penetration total costs initially decrease when adding more DR because these resources have lower capital costs than the CTs that they replace. Even though Emergency DR has a much higher dispatch cost than the displaced CTs, the number of dispatch hours is low enough that it is advantageous to continue adding more DR. However, at higher penetration levels the number of dispatch hours becomes a limiting factor and it is no longer cost-effective to continue replacing CTs with more DR. Overall, and depending on the assumed capital costs and dispatch hours, the cost-minimizing level of Emergency DR ranges from approximately 8% to 12% of peak load as indicated by the red dots.

Figure 24
Production and Reliability Costs vs. Emergency DR Penetration
(Risk-Neutral, Cost of Service)



Notes:
Study RTO reserve margin fixed at 15% with increasing DR offset by reductions in CTs.
Left chart assumes DR dispatch cost of $2,000/MWh; right chart assumes DR fixed costs of $15/kW-yr.

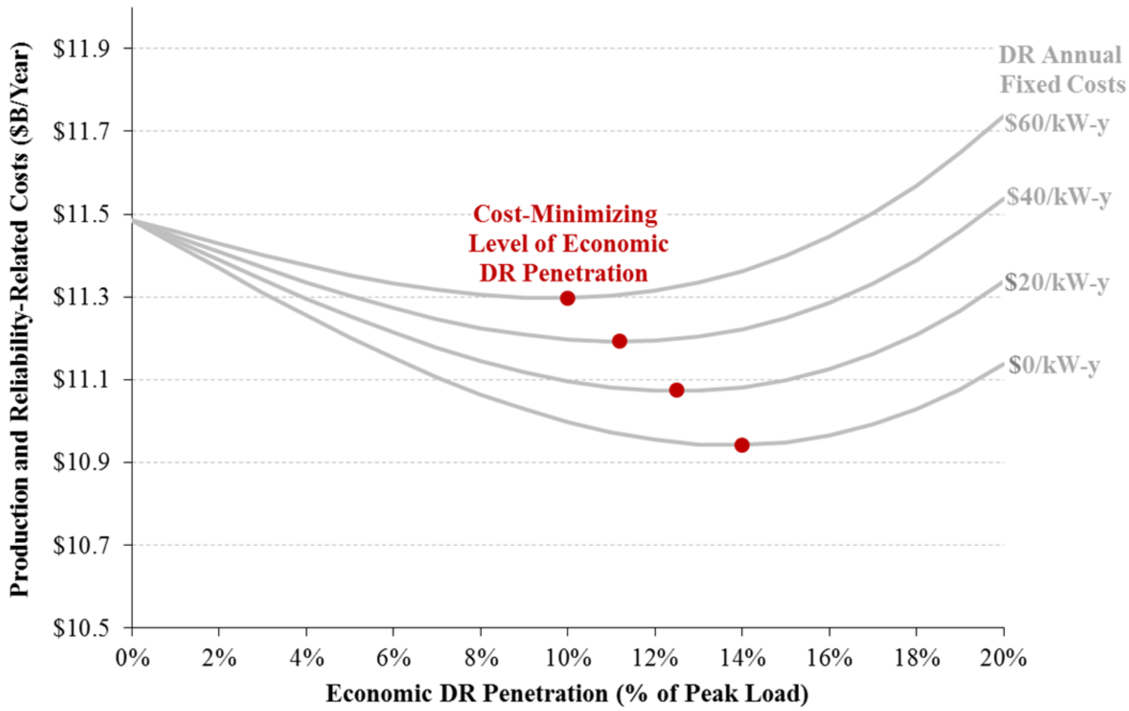
Note that the optimal level of DR penetration is also dependent on the planning reserve margin, which we assumed to be 15%. If the target reserve margin were higher, then higher DR penetrations could be achieved without incurring as many dispatch hours. As a result, the optimal penetration level would be higher. Higher dispatch limits would also increase the optimal penetration levels because Emergency DR, while still a high-dispatch-cost resource, would be able to displace even higher-cost emergency procedures during more hours.

The simulation results highlight the complex role of demand response in reliability planning. DR penetration levels, the design of the products (including dispatch limits and price), and the system load shape all affect the economic and reliability value provided by these resources. The results also show that DR products have to be defined carefully to provide maximum system reliability and economic benefit as customers will only participate in these programs if they are adequately compensated for the fixed and dispatch costs they incur. Ultimately, whether a reasonably efficient portfolio of DR resources will be attracted will depend on: (a) the level of flexibility provided to DR suppliers in defining their own dispatch prices and call-hour limits; and (b) the efficiency of the combined energy and capacity market incentives provided as discussed further in Section IV.C below.

3. Cost-Minimizing Level of Economic Demand Response Penetration

Figure 25 shows the Study RTO production and reliability-related costs as a function of the Economic DR penetration level. The chart is very similar to that shown in the previous section for Emergency DR. As with Emergency DR, adding Economic DR reduces total system costs by displacing CTs with higher capital costs. However, Economic DR is more valuable than Emergency DR in our simulations because: (a) a substantial portion of the Economic DR is assumed to have lower dispatch costs than Emergency DR; and (b) Economic DR is not call-limited. For these reasons, the optimal level of Economic DR penetration ranges from approximately 10% to 14%, depending on the assumed annual fixed costs. However, this level of Economic DR penetration can only be achieved if a sufficient quantity of potential DR resources are willing to participate in the energy markets at the price levels assumed in our simulations (as described in Section II.C.4 above). We further explore the energy and capacity market design implications of high DR penetration levels in Section IV.C below.

Figure 25
Production and Reliability Costs vs. Economic DR Penetration
(Risk-Neutral, Cost of Service)



Notes:
Study RTO reserve margin fixed at 15% with increasing DR offset by reductions in CTs.
Economic DR dispatch costs are set according to the DR energy supply curve from Section II.C.4 above.

D. COMPARISON OF RESERVE MARGIN TARGETS

The preceding sections evaluated the reliability and economic implications of a wide range of study assumptions and system conditions and explained how different reliability and economic objectives would lead to different planning reserve margins. Table 11 provides a brief summary of these results, including the sensitivity of the "optimal" (risk-neutral, cost-of-service) reserve margin to various economic assumptions. Table 12 summarizes the reliability-based and economically-based reserve margins under various system characteristics.

As Table 11 shows, the risk-neutral, economically-optimal planning reserve margins could vary by several percentage points under a range of reasonable cost and other economic study assumptions. For example, different reasonable assumptions for emergency event costs correspond to planning reserve margins ranging from 9.2% to 12.1%. Although this range is substantial, it may be surprisingly small given that the actual cost of emergency events is poorly understood and quite uncertain. Note, however, that the impact of the assumed VOLL, representing the costliest emergency intervention of curtailing firm load, has only a modest impact. Varying VOLL over a wide range from $3,750 to $15,000/MWh results in an economic reserve margin ranging only from 10.0% to 11.6%.

Other important economic assumptions that also affect the optimal reserve margin include: (1) the forward planning period, resulting in planning reserve margins ranging from 9.4% to 11.0% for forward planning periods from two to six years; (2) the CT CONE, resulting in planning reserve margins ranging from 9.5% to 11.0% for CONE values from $100 to $140/kW-year; and (3) the ownership of transmission rights, resulting in planning reserve margins ranging from 8.3% to 12.3% depending on whether the importer owns rights (allowing it to buy power at the lower external price) or the exporter owns rights (allowing it to sell power at the higher external price).[121]

Table 11
Sensitivity of Economically Optimal Reserve Margin to Economic Study Assumptions
(Risk Neutral, Cost-of-Service Perspective)

	Reserve Margin Range *(% ICAP)*	Base Case	Low/High Sensitivity
Base Case	10.30%	n/a	n/a
Emergency Event Costs			
Emergency Generation	10.2% - 10.5%	$500/MWh	$250 - $1000/MWh
Emergency DR	9.9% - 10.9%	$2000/MWh	$1000 - $3000/MWh
Emergency Hydro	10.2% - 10.5%	$3,000/MWh	$1,500 - $6,000/MWh
Voltage Reduction	10.2% - 10.4%	$7,000/MWh	$3,500 - $14,000/MWh
VOLL	10.0% - 11.6%	$7,500/MWh	$3,750 - $15,000/MWh
All Emergency Event Costs	*9.2% - 12.1%*	*Base*	*50% or 200% Base*
Other Assumptions			
Load Forecast Error	9.4% - 11.0%	4 Years Forward	2 Years - 6 Years
CONE	9.5% - 11.3%	$120/kW-y	$100 - $140/kW-y
Transmission Ownership	8.3% - 12.3%	50/50 Ownership	Importer/Exporter Owns

Notes:
Study RTO "optimal" reserve margin from the risk-neutral, cost-of-service perspective.
Impact of economically-determined planning reserve margin on various economic sensitivities.

Table 12 summarizes the reliability-based and economically-based reserve margin targets under the Base Case scenario as well as under each of the alternative simulation cases we examined in

121 See Sections III.A.5 and III.A.2 for additional discussion of forward period and transmission rights assumptions.

the preceding sections. We also show the results from the simulation cases with $3,000/MWh and $1,000/MWh price caps, which we discuss in the context of market design in Section IV of this report. Generally, these results show that differing system size, topology, and other conditions can substantially impact planning reserve margin targets. For example, maintaining a 0.001% Normalized EUE reliability standard could require a reserve margin anywhere from 7.5% up to 15.8% depending on the assumed system topology, size, and other characteristics. Similarly, economically-optimal, risk-neutral reserve margins could vary anywhere from less than 6% to 16.5% for both cost-of-service and societal perspectives.

Nevertheless, changing system characteristics has similar directional impacts on reserve margin targets for all resource adequacy criteria, both in terms of physical reliability and economics. For example, the Island Case always requires higher planning reserve margins because the system is not able to rely on neighbors for any resource adequacy support. Similarly, the Long Neighbors Case always allows for lower planning reserve margins in the Study RTO due to the greater availability of neighbor support.

Table 12
Reliability-Based and Economically-Based Reserve Margin Targets
(Across Base and Sensitivity Case Simulations)

Simulation	Reliability-Based			Risk-Neutral, Cost-Minimizing	
	0.1 LOLE	2.4 LOLH	0.001% Normalized EUE	Cost-of-Service Perspective	Societal Perspective
Base Case	15.2%	8.2%	9.6%	10.3%	7.9%
Lower Price Caps					
$1,000 Price Cap Case	15.2%	8.2%	9.6%	8.7%	7.9%
$3,000 Price Cap Case	15.2%	8.2%	9.6%	9.5%	7.9%
Smaller System Size					
40% Size Case	14.8%	<6%	7.5%	<6%	<6%
40% Size and Transmission	15.1%	6.9%	8.1%	<6%	<6%
Neighbor Assistance					
Long Neighbors Case	13.0%	<6%	7.0%	8.0%	<6%
50% Transmission Case	15.8%	9.8%	10.0%	12.3%	10.5%
Island Case	18.5%	16.5%	15.8%	16.5%	16.5%
Marginal CC Case	15.3%	8.3%	9.8%	10.1%	7.7%

IV. MARKET DESIGN IMPLICATIONS

Up to this point, we evaluated only the reliability and economic implications of different planning reserve margins, system conditions, and resource penetration levels with respect to annual system costs. Much of that analysis is relevant irrespective of market design and whether generation resources are cost-of-service regulated or restructured. However, the ability to achieve a particular planning reserve margin, as well as the economic implications for customer costs, supplier returns, and market prices, cannot be evaluated without considering the market design of the study region. In cost-of-service regulated environments, resource adequacy is achieved through integrated resource planning and supported by rate recovery for all approved investments in generation. In market-based environments, investments can only be attracted if prices are high enough on average for suppliers to earn a sufficient return on their investments.

In this section, we evaluate the implications for both customers and suppliers with respect to: (a) energy-only markets that do not have a reliability requirement and whose reserve margin is determined by the quantity of resource investments that can be attracted by revenues from the region's energy and ancillary services (A/S) markets; (b) capacity markets that *do* have a planning reserve margin standard, with supply investments attracted by a combination of energy, ancillary service, and capacity market revenues; (c) the implications of integrating high levels of demand response into energy-only and capacity markets; and (d) a comparison of customer and supplier impacts under various energy-only and capacity market designs.[122]

A. ENERGY-ONLY MARKETS

Restructured markets, including both energy-only markets and regions that rely on capacity markets, can only attract investments in needed resources if prices are high enough on average that suppliers can expect a sufficient return on their investments. In "energy-only" markets, there is no mandatory minimum reserve margin. In these markets, including Texas, Alberta, Australia's NEM, and Scandinavia, the reserve margin achieved depends on the market prices for energy and ancillary services, with new generation being built only when suppliers believe that their investments can earn their cost of capital. In other words, there is no guarantee that enough generation will be built to maintain a certain reserve margin or resource adequacy level on average.[123]

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[122] In the following sections, we briefly explain the major features and differences between energy-only and capacity markets, but stop short of a full theoretical treatment. For a more comprehensive survey of market designs for resource adequacy, we refer the reader to Pfeifenberger, Spees, and Schumacher (2009); and Spees, Newell, and Pfeifenberger (2013).

[123] Most so-called "energy-only" markets also rely on some reliability backstops to prevent unacceptably low reliability events. For example, Scandinavian markets maintain "strategic reserves" of usually high-cost, older capacity that is only dispatched under emergency conditions at very high prices (*i.e.*, with market prices approximately reflecting a world in which those strategic reserves did not exist at all). Similarly, Texas regularly procures demand response supplies that are to be deployed only during emergency conditions. Many markets, including Texas and Alberta for example, also have mechanisms for administrative intervention into the markets if reliability is expected to drop to very low levels. See Pfeifenberger, Spees, and Schumacher (2009), pp. 28-29; AESO (2008); European Commission (2012), p. 8.

In this section, we evaluate the economic and reliability implications of resource adequacy within energy-only markets, including: (1) how the equilibrium reserve margin is determined within energy-only markets; (2) the preconditions that are necessary in order for the equilibrium reserve margin to reflect the socially optimal level; (3) the volatility in energy market returns that suppliers would have to expect in an energy-only market; (4) the impact of different system conditions and modeling assumptions; and (5) the "missing money" problem that can cause energy-only markets to fail to attract investments sufficient to meet system operators' or policy makers' reliability objectives.

1. Economic Equilibrium at the Cost of New Entry

In energy-only markets, system operators are not able to mandate a minimum planning reserve margin. Instead, the reserve margin achieved within an energy-only market depends on market prices and on suppliers' expected returns. As shown in Figure 26 for the Base Case simulations, the energy margins that a new gas CT would expect to earn on average in the Study RTO are a downward-sloping function of reserve margin. We show energy margins relative to the CONE value of a CT that reflect the average annual *net revenues* required to recover investment and fixed costs over the economic life of the plant.[124]

The figure shows that average annual energy margins are high at very low reserve margins because tight supply conditions create high energy prices and more frequent price spikes. Under such conditions, an energy-only market would attract additional investments because suppliers would expect to earn on average more than enough in the energy market alone to recover their fixed costs. As the market attracts more investments and reserve margins increase, energy prices and supplier returns decline. The energy-only market will continue to attract incremental investments until energy margins drop to CONE, which represents an equilibrium point for achievable reserve margin. No additional investment would be attracted beyond this point because investors would not expect to recover their costs of new entry.

In our Base Case simulations, the Study RTO would achieve an economic equilibrium reserve margin of 7.9% in the Study RTO (which corresponds to a 16.5% reserve margin over the combined four-system area, as explained in Table 7 in Section III above). This economic equilibrium is indicated by the red dot in Figure 26. Note, however, that because the achieved reserve margin is determined entirely by market forces, there is no guarantee of achieving any specific resource adequacy level in an energy-only market. In our hypothetical system, the economic equilibrium reserve margin is lower than the reserve margin that would be required to maintain a typical reserve margin of 15.2% under the 0.1 LOLE standard, 8.2% under the 2.4 LOLH standard, or 9.6% under a 0.001% Normalized EUE standard.

Finally, we note that to illustrate this equilibrium reserve margin result, we assumed that a natural-gas-fired CT is the marginal technology over the entire range of reserve margins. A more precise determination of equilibrium conditions would evaluate not only the equilibrium reserve margin but also the equilibrium resource mix. A system in disequilibrium would

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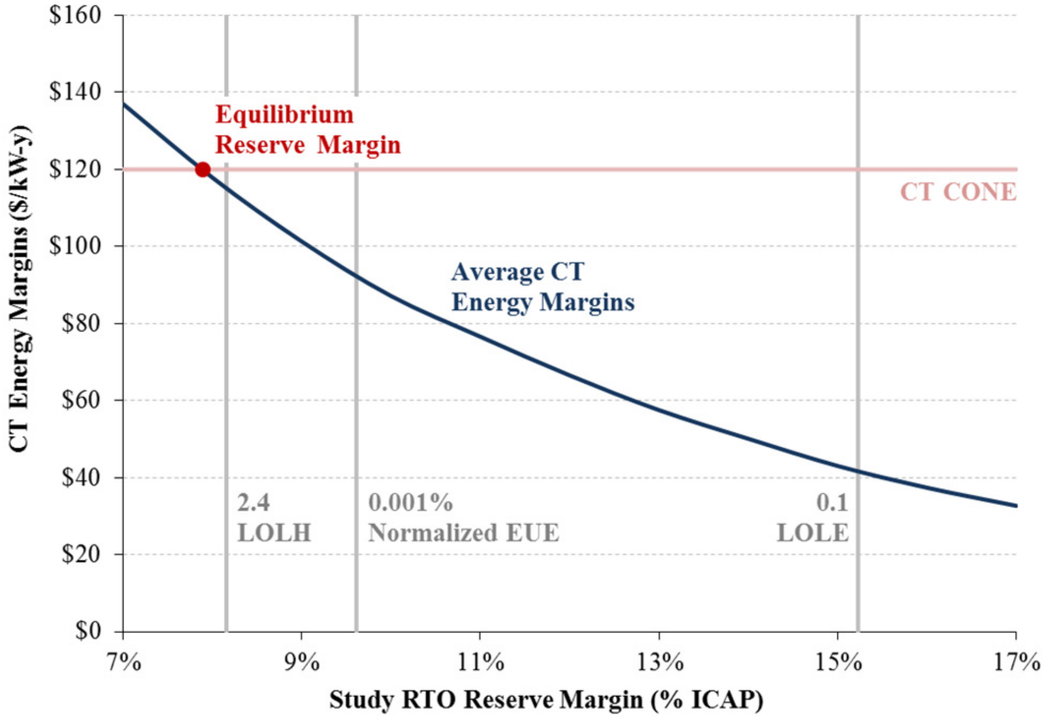
[124] We refer to "net revenues" as the revenues earned in energy and ancillary service markets net of the plant's variable operating and maintenance costs. Our simulation results show only net energy revenues as they do not separately consider ancillary service markets and associated revenues.

experience entry (or exit) of the most profitable (most uneconomic) types of assets from among many asset classes, and would reach true equilibrium at a particular reserve margin with a particular resource mix. We do not evaluate equilibrium resource mix in our study, but note that actual power markets will always experience at least some disequilibrium due to changing system conditions, regulations, and supplier expectations over time.

Figure 26
CT Energy Margins vs. Study RTO Reserve Margin



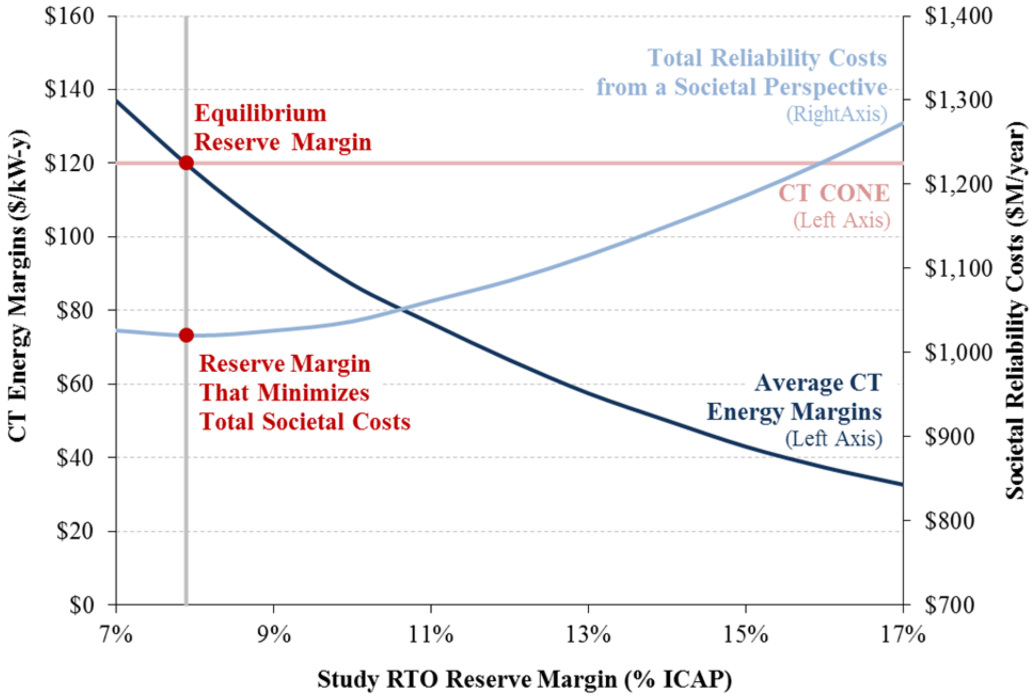
Notes:
CT energy margins in the Study RTO are from the Base Case simulation.

2. Conditions for Achieving Socially Optimal Investment Levels

The most important benefit of energy-only markets, compared to other market designs for resource adequacy, is that energy-only markets theoretically can attract the optimal, welfare-maximizing level of investments from a societal perspective. This is because prices in a perfectly-designed energy-only market will always reflect the marginal system cost defined by the intersection of supply and demand. This means that customers are able to choose how much reliability for which they are willing to pay. For example, some customers place a relatively low value on reliability, and so would rather reduce consumption than pay the $3,000/MWh price realized when emergency hydro resources need to be dispatched in our simulations. Other customers place a high value on service and so will be willing to pay the $7,000/MWh price incurred when implementing voltage reductions. In such a perfectly-designed energy-only market, the decisions of suppliers, customers, and the system operator will all be made relative to the marginal societal costs and benefits of their actions.

We show CT energy margins relative to CONE for our Study RTO Base Case in Figure 27. The figure, which assumes risk neutrality for all market participants, shows CT energy margins relative to CONE (left axis) and total annual societal reliability-related costs (right axis).[125] As explained in the previous section, the energy-only market will achieve an equilibrium reserve margin of 7.9%. This is also the reserve margin that will minimize total societal costs as tabulated in Section III.A.3 above.[126]

Figure 27
CT Energy Margins vs. Study RTO Reserve Margin and Societal Costs



Notes:
CT energy margins vs. societal reliability costs in Study RTO from Base Case simulation.
See Section III.A.3 for the derivation of risk-neutral, societal reliability-related costs.

The reason that an energy-only market can achieve this outcome is that a perfectly-designed energy market will produce hourly energy prices equal to true marginal system costs.[127] During

125 The reader may note that we now shift from a discussion of "societal welfare-maximizing" reserve margins to a discussion of "societal cost-minimizing" reserve margins. We make this change as a matter of simplicity and convenience, since the objectives of "maximizing welfare" and "minimizing cost" are identical in a system with inelastic demand like our Study RTO. We do not ignore the possibility of elastic demand however, but instead account for net impacts on customer welfare indirectly by tabulating the "costs" imposed by dispatching economic DR, emergency DR, and involuntary load shedding. An alternative approach in which we calculate total societal welfare directly (consumer surplus plus producer surplus) would be more conceptually pure, but would unnecessarily complicate our discussion.

126 Note that this reserve margin does not have any pre-determined relationship to the reserve margin that minimizes costs from a utility cost-of-service perspective as evaluated in Section III.A.2 above.

127 The perfectly-designed market will also attract the optimal proportion of baseload, intermediate, and peaking units for the same reason that it would achieve the optimal reserve margin. In each case, for baseload as well as peakers, the net revenues available from the market will be equal to the net societal value created by displacing higher-cost resources or emergency actions. This means that baseload units will have sufficient incentives to enter the market only if the net societal value they create is equal to or

Continued on next page

most hours, marginal system costs are equal to the production costs of the highest-cost generation or demand response asset dispatched to meet load. During peaking and scarcity events however, marginal system costs rise to higher levels driven by the marginal cost of emergency procedures such as calling emergency DR, emergency generation, emergency hydro, operating reserves shortages, voltage reductions, or load curtailments. This means that the profit that a new generating plant earns in a particular hour is exactly equal to the marginal reduction in the societal costs that it provides.[128] If the reduction in total annual system costs is greater than the marginal unit's total annual capital and fixed costs at CONE, then total societal costs will be reduced by that investment and suppliers have an incentive to enter the market.

As promising as these theoretical benefits sound, we stress that actual power markets cannot be expected to achieve the optimal reserve margin in all cases. We are able to demonstrate the result in our simulations only because we have constructed a carefully-designed scarcity pricing mechanism to ensure that our simulated energy prices are always exactly equal to marginal system costs. Achieving such perfect energy prices that exactly equal marginal system costs is difficult if not impossible under real-world conditions. If those imperfections cause energy prices to be too high on average, the market will attract more than the optimal level of investments and will achieve a higher reserve margin. Of greater concern to most regulators and suppliers is the possibility of the opposite outcome in which energy prices and the resulting reserve margins are too low, a topic that we discuss further in Section IV.A.4 below.

There are three types of factors that make it difficult to set prices perfectly in wholesale electric markets. First, there is insufficient integration of price responsive demand in wholesale electric markets, because most customers pay only a fixed price for energy and so have no incentive to respond to wholesale market conditions. Even among customers that do participate in wholesale DR programs or retail pricing that encourages price response, their willingness to pay for energy may not be fully incorporated into wholesale energy market prices due to the DR program design, technical challenges in price formation, or lack of enabling technology. Second, in circumstances when operator interventions are needed to address emergency conditions, prices can be artificially suppressed by the "additional supply" that the intervention creates (*e.g.*, by dispatching emergency DR or implementing a voltage reduction). Several RTOs are working on

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greater than their investment costs. There is also a displacement effect among resources in that adding 1 MW of baseload would reduce net revenues to CTs, and adding 1 MW of CTs would reduce net revenues to baseload (although by a lesser amount). Overall, one would expect an investor to add the most profitable resource type at any given time in a way that moves the system toward an optimal equilibrium reserve margin and resource mix. Again, any deviations from perfect pricing that reflects marginal system costs will not only cause the equilibrium reserve margin deviate from the optimal reserve margin, but it will also cause the resource mix to deviate from the optimal resource mix.

128 For example, consider the impact of adding a very small 1 MW CT with production costs of $62.50/MWh as in our Base Case. In an hour when load shedding would be required in the absence of the CT, the reduction in societal costs is equal to: (a) the reduction in unserved energy, times the VOLL, or 1 MWh times $7,500/MWh; minus (b) the increase in total production costs incurred by dispatching the CT, or 1 MWh times $62.50/MWh. This reduction in total societal costs is also equal to the hourly energy margins earned by the CT which is the hourly price minus production cost (*i.e.*, price at $7,500/MWh minus cost at $62.50/MWh).

efforts to prevent such price suppression, but these efforts are still ongoing. Finally, if an RTO opts to set administratively-determined scarcity prices to prevent price suppression during emergency events, it is a remaining challenge to determine the correct price for these events, such that the administrative price is reflective of the marginal cost of the reliability interventions. These are challenges that energy markets across North America are currently addressing as they attempt to improve their pricing mechanisms, particularly during scarcity hours.[129]

3. Volatility in Supplier Energy Margins

Figure 28 summarizes annual energy margins earned on average for a new CT (on the left) and a new CC (on the right) at different reserve margins. The figure also shows the range of annual energy margins that would be realized in spot energy markets due to uncertainties such as weather, load growth, hydro conditions, or outages. The annual average of energy margins reflects the expected value across all 9,600 simulations for each reserve margin.[130]

To demonstrate the year-to-year volatility in supplier returns for an unhedged supplier, we also show the spot energy margins that a new unit would earn in the median year, along with the middle 50% of all years (the range between the 25th and 75th percentiles) and the middle 80% of all years (the range between the 10th and 90th percentiles). The median energy margin is representative of a "typical year" in the sense that there is a 50% chance that the actual energy margins will be above or below that value. The 90th percentile (top gray line) is particularly interesting, as it approximately represents a "once in ten years" event in which suppliers could earn more than these energy margins due to unusual tight supply or high load conditions.

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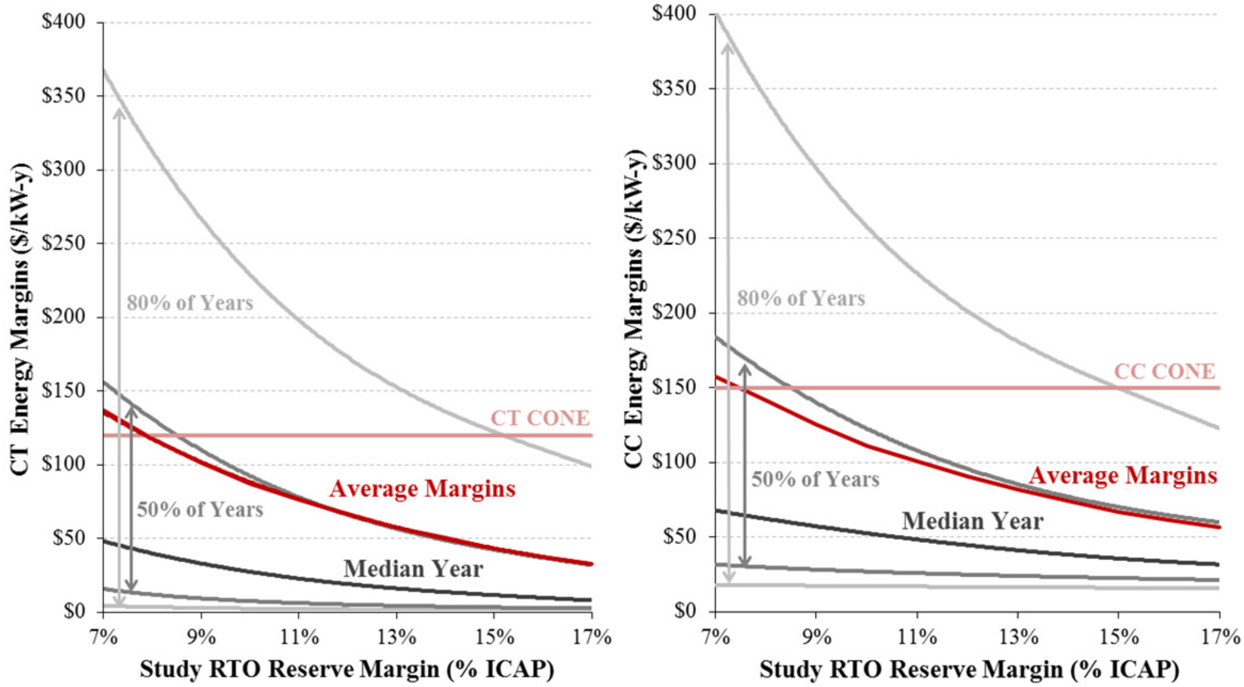
[129] For a more comprehensive discussion of scarcity pricing mechanisms, including how the energy-only markets of Alberta and Texas are addressing these and other challenges, see Newell, *et al.*(2012),Section V.A.2; Pfeifenberger, *et al.* (2009), Section IV; and Pfeifenberger, *et al.* (2011a, 2013).

[130] As discussed in Section II.A, each of the 9,600 simulations for the Base Case and Change Cases estimates hourly reliability and economic system results for a full calendar year, with each of the 9,600 simulations representing different load shapes, economic forecast uncertainties, hydro conditions, unit outages, *etc.*

Figure 28
Volatility in CT (left) and CC (right) Energy Margins vs. Reserve Margin

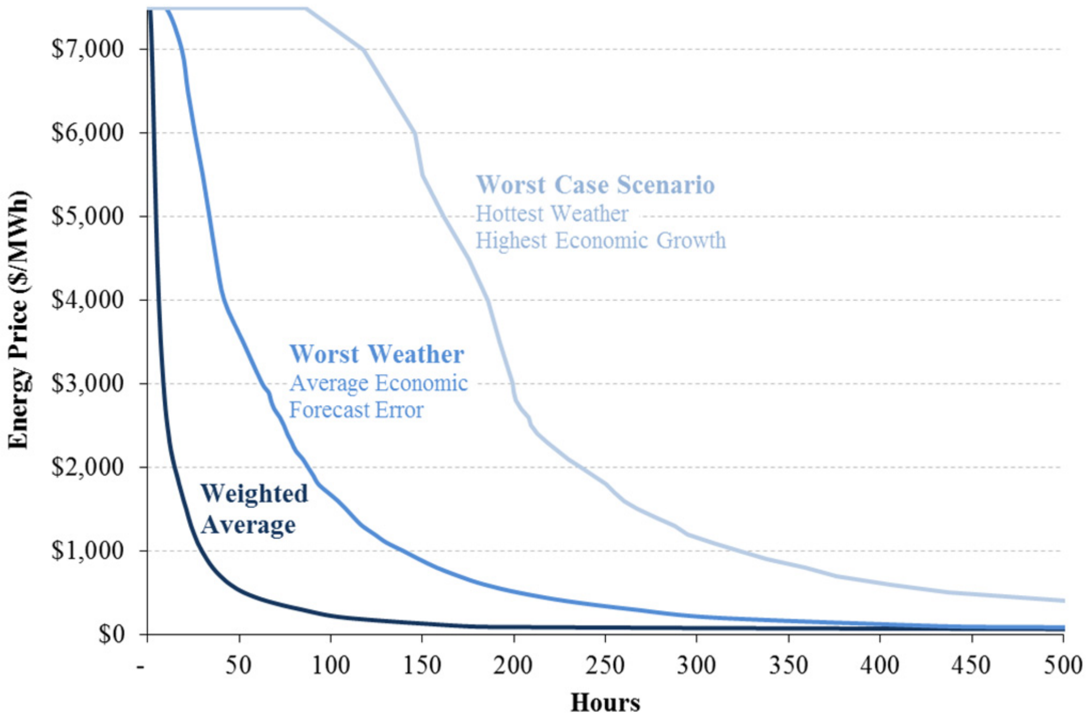


Notes:
CT and CC energy margins the Study RTO are from the Base Case simulation.
Gray lines represent the 10^{th}, 25^{th}, 50^{th}, 75^{th}, and 90^{th} percentile estimates of spot energy margins (*i.e.*, net revenues earned in spot energy market without forward contracting or other risk mitigation).

These results for CTs' and CCs' annual energy margins show that year-to-year volatility in supplier returns is quite large. For example, assuming no forward contracting, at the 7.9% equilibrium reserve margin at which a new CT will earn CONE on average across all years, we estimate that the plant would earn only approximately $30/kW-year (30% of CONE) in the "typical" year. However, the CT would earn more than $260/kW-year (more than twice CONE) approximately once in a decade. Similarly, the figure shows that at the equilibrium reserve margins where a new CC earns its CONE on average across all years, the plant would earn only approximately $55/kW-year (38% of CONE) in a typical year, although the plant would earn more than $290/kW-year (more than almost twice CONE) once in a decade.

Figure 29 further illustrates spot energy market volatility by comparing three annual price duration curves at the equilibrium, the 7.9% reserve margin level. The first price duration curve is based on the weighted average across all 9,600 annual simulations (dark blue line) while the lighter blue lines illustrate a worst weather scenario (medium blue) and a worst weather combined with highest load growth scenario (light blue). On average over the years, spot energy prices would rise to high levels above $1,000/MWh only approximately 35 hours per year, while prices would rise above $1,000/MWh in approximately 140 hours under the worst weather year (and the weighted average of economic growth forecasting errors) and in approximately 325 hours in the worst case scenario that combines the worst weather year with the highest unanticipated load growth. Note that one would not expect prices this high in many markets even under such a worst case scenario, since many markets maintain reserve margins that are much higher than the 7.9% shown in the figure and also have lower price caps than the $7,500/MWh utilized in our Base Case simulations.

Figure 29
Price Duration Curve at the 7.9% Equilibrium Reserve Margin



Notes:
Study RTO Base Case Price duration curve on average and in extreme weather and load growth cases.

The reason that, in the absence of forward contracting and hedging, supplier energy margins can rise so high relative to their median or even average annual levels is that market prices in most years will be set by the marginal costs of the generation fleet in nearly all hours. However, both our Study RTO and actual energy-only markets will also experience periodic severe price spikes that are driven by scarcity conditions reflecting extreme heat waves or unanticipated high load growth.[131] Under these conditions, market prices can rise to very high levels as the need for high-cost emergency operating procedures increases. Realized prices in our Study RTO rise with the severity of the shortage event according to the scarcity pricing function described in Section II.E above. Prices may reach as high as the VOLL-based price cap of $7,500/MWh in the extreme circumstances when load must be shed. As explained in the previous section, these periodic, severe price spikes are necessary if the energy-only market is to attract the socially-optimal level of investments.

The VOLL-based $7,500/MWh price cap and administrative scarcity pricing function also mean there is great uncertainty around the spot energy margins that power plants would earn and

[131] For a comparison of the frequency and severity of scarcity pricing events in various real-world energy-only markets, see Newell, *et al.* (2012), Section I.B.

customers would need to pay in any particular year in the absence of forward contracting or hedging. Unhedged suppliers would face substantial investment risk under a market environment in which returns in the median year are less than half the returns that would be expected on average over the years. This also means that the energy margins that a plant could have earned in the spot market in a recent year (or even several recent years) are not a good indicator of the average energy margins that plants will likely earn over their economic life. For example, at the equilibrium reserve margin, a CT selling solely into the spot market would earn less than 30% of CONE in half of all years. Further, though not shown at the scale of this chart, in the most extreme 5% of simulation cases (representing a 1-in-20 event that a unit may experience once over its useful economic life) annual CT margins earned in spot markets rise 5.5 times above CONE.

Overall, these results mean that if suppliers relied solely on spot market sales, a substantial portion of total investor returns would be earned in only a small number of extreme years. To mitigate this risk, asset owners typically use a portfolio of hedges or contracts. But the scale of the volatility nevertheless has a number of implications for lenders, equity investors, and policy makers. In particular, extreme price events (even if mostly hedged) have important political consequences that may trigger administrative or legislative interventions, including interventions that could undermine investment signals needed for resource adequacy. The regulatory risk of such potential interventions would require investors to discount the expected value of energy margins earned in such extreme cases, with greater perceived regulatory risk translating to lower realized investment levels in energy-only markets. We examine these and other considerations related to the risks to total supplier returns more fully in other publications.[132]

Note, however, that neither customers nor suppliers are fully exposed to this level of spot price uncertainty. This is because all prudent suppliers and load-serving entities will mitigate a significant portion of these risks through hedging tools, such as forward contracts. Forward contracting will allow entities to lock in anticipated average prices for the future, meaning that while the contract price will exceed the realized spot price most of the time, it will be far below realized spot prices during extreme outcomes. The farther forward a supplier or load-serving entity is able to hedge,[133] the less spot energy market risk exposure the supplier will have. For example, long-term contracts will mitigate nearly all price risks, including risk factors such as economic growth, weather, and outages. However, hedging even a few months forward will mitigate most weather and outage-related risks. Because weather and outage risks are shown to account for the majority of the uncertainty range in our market simulations, even short-term forward contracts (such as seasonal contracts) will be able to hedge a large portion of the uncertainty range shown above.[134] In either case, the weighted average of energy margins will

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132 We address a number of related questions more extensively in Pfeifenberger and Newell (2011c); and Newell, *et al.* (2012), Section II.

133 Note that to mitigate uncertainty in spot energy margins, suppliers will need to hedge both their energy market revenues and their fuel costs.

134 For example, our Base Case simulations show that for the 7.9% equilibrium reserve margin, the uncertainty range between the 10th and 90th percentiles of CT energy margins is \$320/kW-year. For normal weather and the weighted average of outage risks (*i.e.*, with exposure only to multi-year economic load growth uncertainty), the uncertainty range between the 10th and 90th percentiles is reduced to \$100/kW-year.

not be significantly affected by such hedging activity unless forward contracts sell at a premium above expected average outcomes because buyers are more risk averse than suppliers (or, alternately, at a discount if suppliers are much more risk averse).[135]

The substantial risk mitigation that can be achieved even through seasonal forward contracts is illustrated by the example of ERCOT in 2011 and 2012. The summer weather for 2011 was an example of extreme conditions, while 2012 was milder than normal.[136] Based on stakeholder interviews we conducted for ERCOT in a 2012 study prompted by these extreme events, we learned that both generators and competitive retail suppliers engage in a substantial amount of forward hedging at periods of up to three to five years. On a seasonal forward basis of several months, some retailers even buy hedges sufficient to cover their entire anticipated summer electricity needs. As a consequence, market participants have ample opportunities to mitigate extreme spot prices and are likely to pay or earn prices much closer to the expected average in many years.

Table 13 illustrates the magnitude of risk mitigation through seasonal forward contracting. The table compares seasonal futures prices against realized hourly spot market prices in ERCOT for the Summers of 2011 and 2012. More specifically, the table compares for these two years: (1) the prices for June through September on-peak futures contracts as of April of each year; with (2) the realized on-peak spot prices for the same hours and months.[137] As shown, for the peak months of August 2011 and August 2012, *futures* contract prices for these two months differed by less than $15/MWh or about 20%. In contrast, August on-peak *spot* prices for 2011 and 2012 differed by $175/MWh, or approximately 280% of the average August futures price. This shows that reasonably effective market-based hedging tools are available to market participants who wish to mitigate spot price exposure. How much additional risk mitigation should be achieved by increasing planning reserve margins above the risk-neutral economic optimum is consequently a difficult question that will need to be addressed through additional research.

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135 If buyers are more risk averse they will be willing to pay a premium above expected spot prices to secure a higher level of forward certainty which would then translate into slightly higher supplier returns and realized reserve margins.

136 See an extensive discussion of the Summer 2011 realized prices, scarcity events, and weather events, as well as our evaluation of impact on investors and buyers in Newell, *et al.* (2012).

137 Data from Ventyx (2013).

Table 13
Illustration of Risk Mitigation Achieved by Seasonal Forward Contracting

	Futures Traded in April *($/MWh)*	Realized Real-Time Spot Prices *($/MWh)*	Delta *($/MWh)*
Summer 2011			
June	$45.94	$51.66	$5.72
July	$55.71	$58.67	$2.96
August	$55.71	$209.99	$154.27
September	$42.79	$39.68	($3.11)
Summer 2012			
June	$38.11	$38.22	$0.11
July	$70.07	$31.50	($38.56)
August	$70.07	$34.98	($35.09)
September	$38.62	$29.02	($9.59)

Sources and Notes:
Futures and spot prices are for ERCOT North On-Peak prices.
Futures prices are averaged across all trade dates in April of 2011 or 2012, two to six months prior to delivery, from Ventyx (2013).

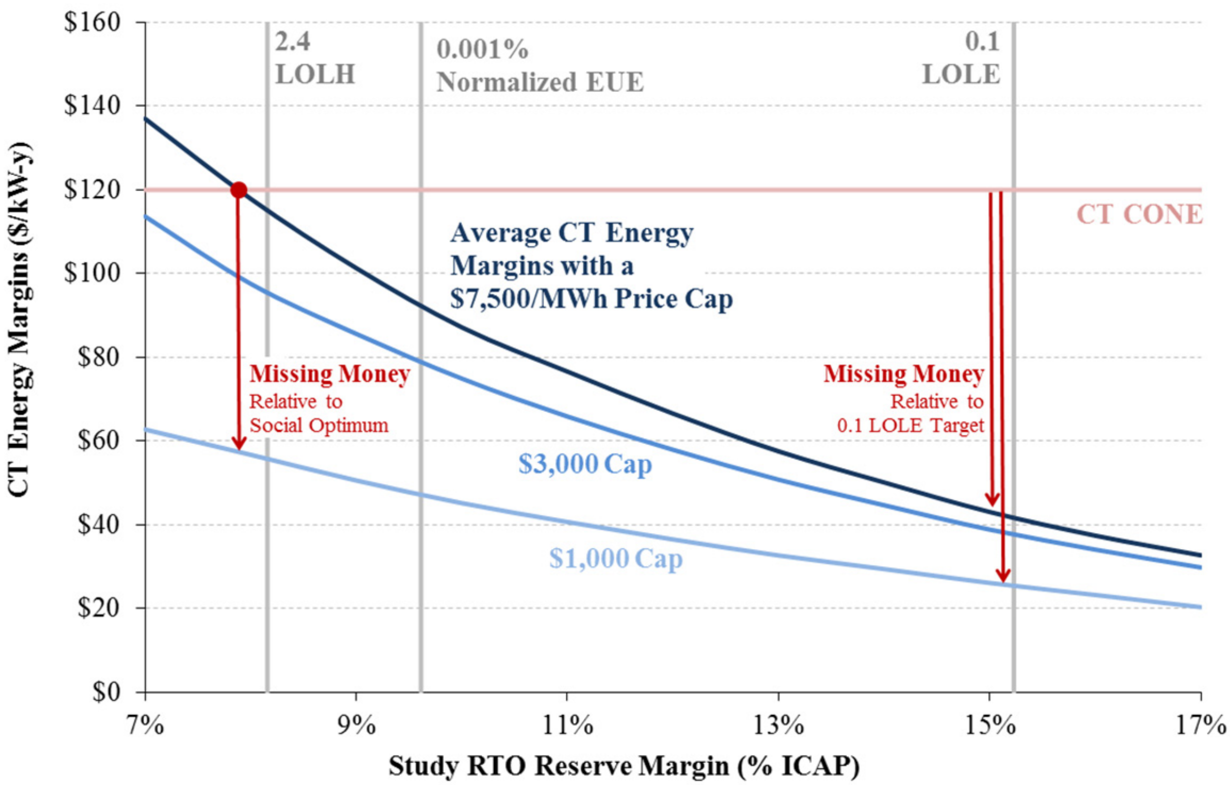
4. Missing Money and the Impact of Price Caps

The Base Case assumes that energy prices can rise up to the VOLL-based energy price cap of $7,500/MWh. As explained above, this VOLL-based price cap, combined with an efficient scarcity pricing mechanism tied to marginal system cost creates efficient real-time energy market price signals that accurately reflect the marginal value of supply at all times. In some cases, particularly during extreme scarcity events, these efficient prices can be very high relative to average prices. Imposing a price cap that is far below VOLL or otherwise suppressing prices during scarcity events will have the inefficient effect of suppressing prices and supplier returns below what is needed to achieve the risk-neutral societally optimal investment levels. This creates a so-called "missing money" problem in the energy market.

Figure 30 demonstrates the concept of missing money for the Study RTO in the Base Case Simulation and in two alternative scenarios in which we introduce price caps of $3,000/MWh and $1,000/MWh. At the 7.9% risk-neutral, societal optimum reserve margin, suppliers earn high enough energy margins to sustain investment. However, imposing price caps of $3,000/MWh or $1,000/MWh eliminates the high prices of some events and causes supplier net revenues to drop to only 84% or 49% of CONE respectively. In other words, the price-capped market would have a "missing money" problem of $20 and $62/kW-year respectively, relative to the energy margins needed to sustain the socially optimal reserve margin.

An even greater "missing money" problem exists if policy makers wish to maintain the 15.2% reserve margin needed to meet the 0.1 LOLE reliability standard. In this case, there are two sources of missing money: (1) energy prices that are suppressed by the price caps; and (2) even if price formation is efficient as in the Base Case, the energy-only market does not achieve an economic equilibrium reserve margin at the planning reserve margin (*e.g.*, to achieve 0.1 LOLE) that regulators may wish to maintain. This topic is the subject of current market reform efforts in Texas.[138]

Figure 30
Energy Margins and "Missing Money" at Different Price Caps



Notes:
Average CT energy margins with price caps of $7,500/MWh (Base Case), $3,000/MWh, and $1,000/MWh.

5. Implications of Varying System Conditions and Study Assumptions

Figure 31 shows average CT energy margins for the Base Case and each of the alternative simulation scenarios that we have examined. Compared to the Base Case, large declines in energy margins would be realized under the lower price cap cases (as discussed above), or in any of the scenarios where the Study RTO is able to rely more heavily on imports from the neighboring regions with higher reserve margins. In these cases, under an energy-only market, the Study RTO would realize an economic reserve margin below minimum the 7% level that we have examined. However, note that in cases where energy margins are driven down by increased neighbor assistance, these lower realized internal reserve margins may not necessarily cause any additional reliability concerns since the Study RTO is also in a better position to rely on physical neighbor assistance during these events.

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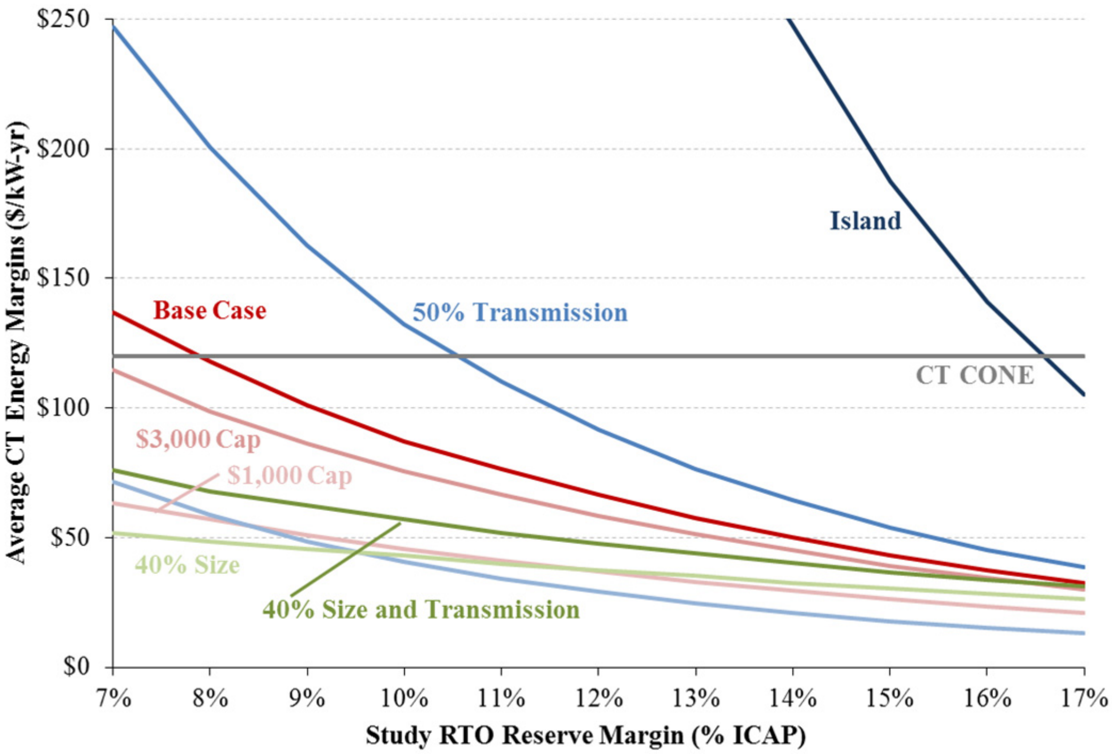
[138] See Newell*, et al.* (2012), Sections I.D-F.

The largest increases in CT energy margins are caused by reduced transmission interconnections with neighboring regions. In fact, the 50% Transmission and Island Cases would increase supplier returns sufficiently to increase the Study RTO's equilibrium reserve margin to 12.3% and 16.5% respectively.

Figure 31
Summary of Average CT Energy Margins for All Simulated Cases



Notes:
Average CT energy margins in the Base Case and all change case scenarios.

Overall, comparison of these results shows that energy margins are heavily influenced by conditions experienced in neighboring regions, particularly when those neighbors are strongly interconnected. When the Study RTO is experiencing a severe shortage condition, it can partially alleviate the shortage and reduce energy prices by importing from neighboring systems. The price-moderating effect of such imports will be greater in more interconnected systems and neighboring systems with higher load diversity (so that scarcity does not happen simultaneously in all regions). However, the reverse can also be true. When the neighboring regions experience an extreme price spike, this will also attract imports from the Study RTO that will introduce scarcity-level prices in the Study RTO as well.

The overall impact of neighboring regions on Study RTO prices and energy margins therefore depends on the characteristics of the outside system, the level of load diversity among the systems, and the strength of interconnections. For example, because the systems we examine are quite similar and have significant load diversity, increasing interconnections will generally tend to moderate prices. In select circumstances however, expanded interconnections could also increase price volatility in the Study RTO if a neighboring region has a greater potential for severe price spikes and shortage conditions. This would generally be the case for neighboring regions that are hydro-dominated with the potential for extreme shortages during low-water conditions that occur only once every five or ten years.[139]

B. CAPACITY MARKETS

Bilateral and centralized capacity markets were first implemented in the U.S. in the late 1990s as a means of achieving the prevailing 1-in-10 resource adequacy standards within restructured markets. Restructured markets rely on voluntary supplier investments to sustain resource adequacy, with incremental investments attracted only when suppliers can anticipate operating margins sufficiently high on average to cover the plants' fixed costs, recover investments, and earn a return equal to their cost of capital.[140]

The primary advantage of restructured markets that include a capacity market relative to energy-only markets is that the system operator is able to ensure that the administratively-determined planning reserve margins will be achieved. Depending on the policy objectives, these reserve margins may be set to achieve either: (a) the reliability objective such as 1-in-10, as is the case in the capacity markets of PJM, ISO-NE, and NYISO; or (b) an economic objective such as minimizing societal or customer costs, as in the proposed Italian capacity market.[141]

1. Capacity Payments Required to Achieve Reliability Targets

As discussed in Section IV.A above, energy-only markets by themselves will maintain some equilibrium level of investments, but will not necessarily achieve any particular administratively-determined reserve margin target. As explained in Section IV.A.4, the additional supplier returns required to achieve a particular target reserve margin is often referred to as "missing money".[142]

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139 This type of situation is one that we have previously examined in Alberta that despite little hydro resource of its own is exposed to the risk of low-hydro conditions via its interconnection with BC Hydro. See Pfeifenberger and Spees (2011a), Section III.F.

140 Note that even restructured markets do not rely entirely on merchant entry for all new supply. There are usually at least a small proportion of new assets within each footprint that are built on a regulated basis. An example is public power entities that build for self-supply. However, we classify a market as "restructured" if it will require at least some merchant entry to maintain resource adequacy in the region. This is the case, for example, in PJM where most new entry must come from merchant investors, although some new entry will be built on a regulated basis such as by Dominion, by a number of municipalities and cooperatives, or under the direction of state entities as in a selection of contracts in New Jersey and Maryland.

141 We note that these markets actually express the resource adequacy standard as a "demand curve" for capacity that covers a range of reserve margins, although the range is developed around the underlying reliability or economic objective as discussed further in Section IV.B.4 below.

142 For a discussion of investment shortfalls and the "missing money" problem in energy-only markets, see Cramton and Stoft (2006), Joskow (2008), and Pfeifenberger, *et al.* (2009). Note, however, that not all energy-only markets suffer from a missing money problem, and the problem can be addressed through means other than capacity markets. See, for example, Pfeifenberger and Spees (2013), documenting

Continued on next page

The missing money problem can be solved in deregulated markets by imposing resource adequacy standards on all LSEs. Such a resource adequacy standard requires LSEs to procure either sufficient generation or DR capacity to serve their own customers' coincident peak load plus the specified mandatory reserve margin. Such an LSE-based resource adequacy standard is imposed in all capacity markets that cover primarily deregulated regions, such as in NYISO, ISO-NE, and PJM. It is also used in California and regions with primarily (but not exclusively) regulated utilities such as MISO.[143]

Imposing a resource adequacy standard on LSEs automatically creates a bilateral market for capacity because it creates demand for installed capacity that is separate from the demand for energy and ancillary services. As a result, LSEs will have to pay for capacity to secure the needed obligations.[144] Within centralized capacity markets—as is the case in PJM, ISO-NE, and NYISO—the RTO procures the needed capacity resources on behalf of all customers and then assigns procurement costs to individual LSEs in proportion to peak load during the delivery period. However, regardless of whether the capacity market is centralized or bilateral, the existence of an enforceable resource adequacy standard means that the system operator will always be able to achieve the specified planning reserve margin.

The size of the capacity payments required to maintain the resource adequacy standard is a function of the target reserve margin as shown in Figure 32. Suppliers must anticipate being able to earn total operating margins equal to or greater than CONE before they will invest in the new resources. As explained in Section IV.A.1 above, energy margins exceed CONE at Study RTO reserve margins up to 7.9% (which corresponds to a 16.5% reserve margin in the combined four-system area, see Table 7 above). This means that only if the anticipated Study RTO reserve margin dropped below 7.9% would suppliers invest without the prospect of earning additional capacity payments. This also means that the capacity price would be zero if the Study RTO imposed a minimum reserve margin requirement at or below 7.9%.

For reserve margin requirements greater than 7.9% however, suppliers will not be willing to invest based on energy margins alone. At these higher reserve margins, suppliers must expect capacity payments equal to their Net CONE, which is the difference between their CONE and their anticipated energy margins. As shown in Figure 32 for our Base Case simulations, the equilibrium capacity price (red line) increases with the reserve margin requirement. This is because energy prices and suppliers' energy margins decrease causing Net CONE to increase.

Continued from previous page

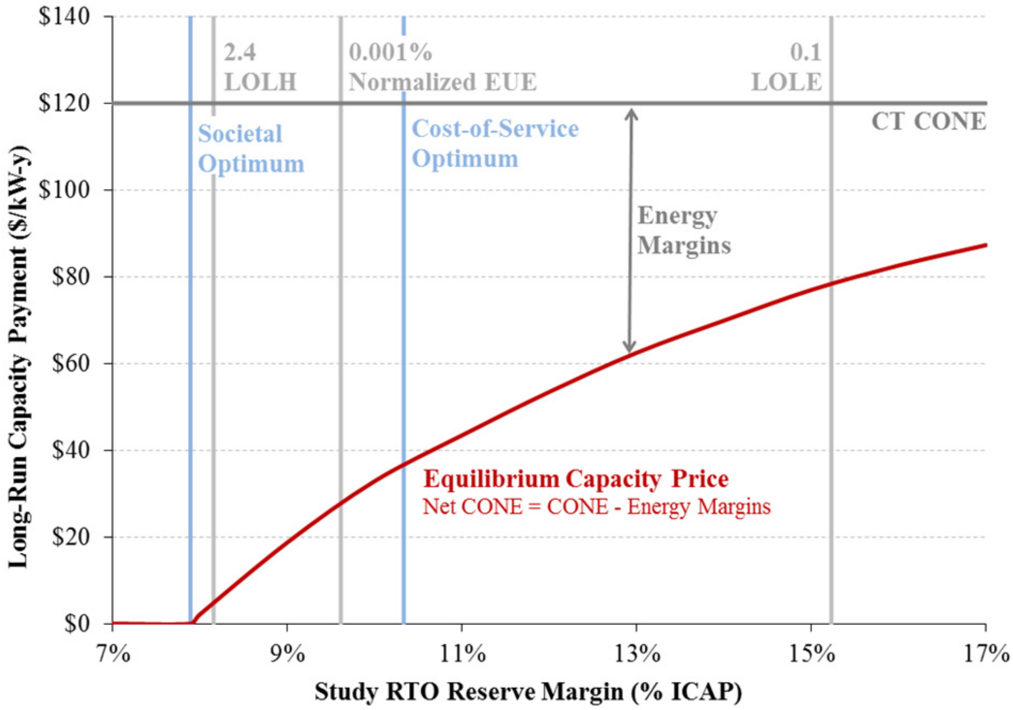
market prices that support sufficient investment in the Alberta energy-only market; and Newell *et al.* (2012) discussing a range of options, with and without a capacity market, to address a missing money problem in the Texas energy-only market.

143 For additional discussion of these capacity market designs as well as various alternative market designs for resource adequacy, see Spees, *et al.* (2013); and Pfeifenberger, *et al* (2009).

144 In regions with primarily cost-of-service regulated utilities, most of these capacity commitments are determined through integrated resource planning (IRP) and then secured through self-supply or long-term PPAs for bundled energy and capacity. However, there are often still at least some additional transactions for capacity as a distinct product. For example, see an analysis of California's short-term bilateral market for capacity in CPUC (2011), particularly in Section 4.3. See also Pfeifenberger, *et al.* (2012).

At the 15.2% reserve margin needed to maintain 0.1 LOLE, for example, an investor in a new CT would expect to earn approximately \$40/kW-year in energy margins on average, while the total annualized investment and fixed cost (*i.e.*, CONE) is \$120/kW-year. That supplier would not voluntarily invest unless capacity prices were expected to be at least \$80/kW-year on average over the economic life of the plant.[145] By comparison, a capacity price of less than \$30/kW-year would be needed to sustain the lower 10.3% reserve margin that is consistent with the risk-neutral cost-of-service optimum as discussed above.

Figure 32
Equilibrium Capacity Price vs. Reserve Margin Requirement



Notes:
Equilibrium capacity price equal to CT Net CONE of Base Case simulation.

2. Impact of Lower Energy Market Price Caps on the Capacity Market

Because capacity prices must be equal to Net CONE over the long-run to sustain a particular reserve margin, any factors that cause anticipated energy margins to drop will also cause capacity prices to increase if the reserve margin is to be maintained. Figure 33 illustrates this effect for our Study RTO, by showing the equilibrium capacity price level for simulation cases where the energy price cap is: (a) set at the VOLL of \$7,500/MWh as in the Base Case; (b) reduced to \$3,000/MWh; and (c) reduced to \$1,000/MWh.

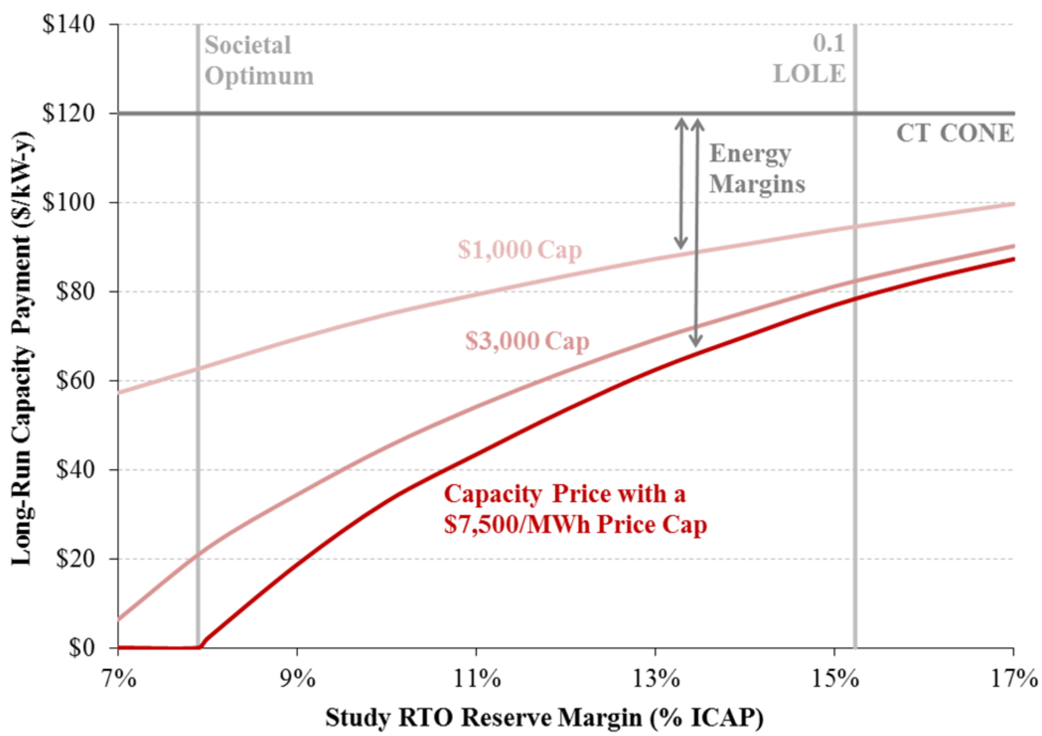
As explained in Section IV.A.4 above, reducing the price cap below VOLL or otherwise suppressing energy prices below marginal system costs will result in under-investment in an energy-only market design. This is not the case in regions with reserve margin requirements,

[145] In other words, Net CONE (\$80/kW-year) = CONE (\$120/kW-year) – Energy Margins (\$40/kW-year).

because any reduction in energy margins will be offset by an increase in supplier compensation through increases in capacity prices. As Figure 33 shows, at any level of reserve margin, lowering the cap on energy prices significantly increases capacity prices. The impact of price caps is greater at lower reserve margins because scarcity conditions and associated price spikes are encountered more frequently at the lower margins.

This interaction between energy margins and capacity market prices also means that regions with resource adequacy requirements and associated (bilateral or centralized) capacity markets will be able to achieve their reliability targets even if energy prices are artificially suppressed. This does not mean, however, that capped or otherwise suppressed energy prices have no consequences on market efficiency. Rather, overall market efficiency will be lower because the capped or otherwise lower energy prices will lead to inefficient investment decisions, inefficient hedging and forward contracting incentives, inefficient demand response, inefficient real-time performance incentives, and inefficient dispatch of resources.

Figure 33
Equilibrium Capacity Prices with Different Energy Market Price Caps



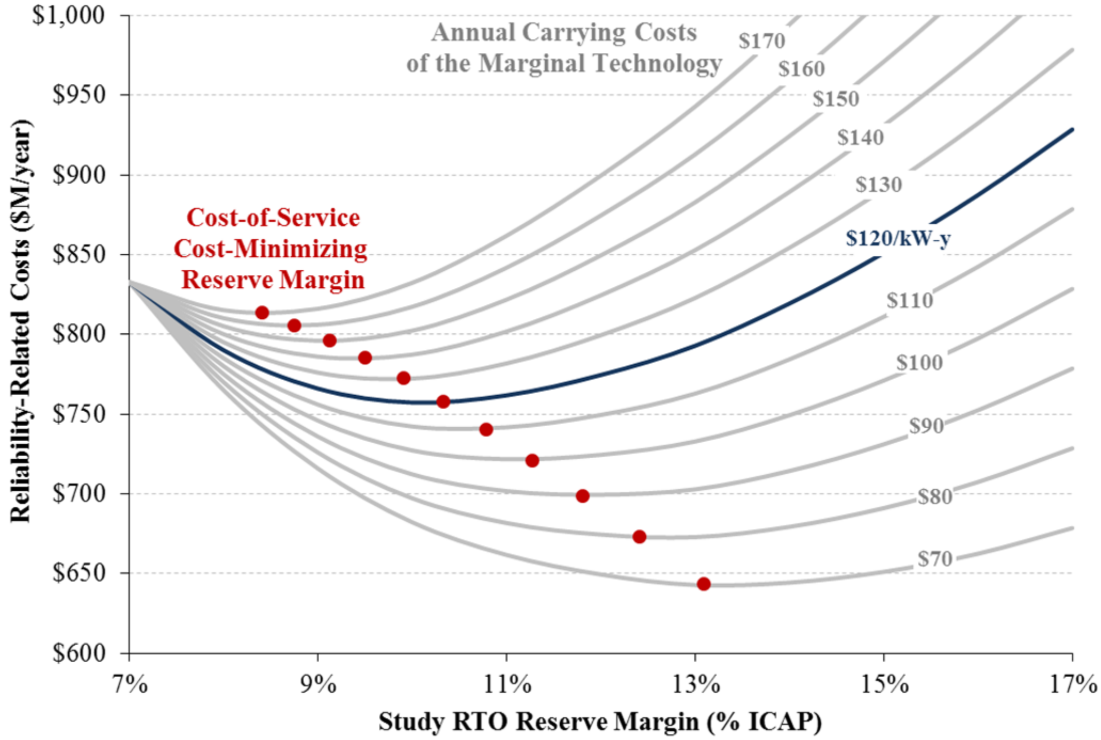
Notes:
Equilibrium capacity price is at CT Net CONE.
Calculated at price caps of $7,500/MWh (Base Case), $3,000/MWh, and $1,000/MWh.

3. Cost-Minimizing Capacity Demand Curves

The optimal, cost-minimizing reserve margin also depends on the levelized fixed costs of adding more capacity resources to the system. In estimating the cost-minimizing reserve margin in Sections III.A.2 and III.A.3 above, we assume levelized fixed costs equal to a CT CONE of $120/kW-year. In reality there is some uncertainty in CONE from an administrative perspective, due to variability in construction costs, financing costs, and even technology specifications among potential investors.

Figure 34 shows how total reliability-related costs change with varying CONE levels and reserve margins, and highlights the minimum average cost point with a red dot in each case. The figure shows total reliability-related costs as calculated in Section III.A.2 from a risk-neutral, cost-of-service perspective. The figure also shows that changes in the assumed level of CONE shift the economically-optimal reserve margin by several percentage points. Varying CONE between \$70/kW-year to \$170/kW-year corresponds to cost-minimizing reserve margins that range from 8.4% to 13.1%.

Figure 34
Cost-Minimizing Reserve Margin with Varying CT CONE
(Risk-Neutral, Cost of Service Perspective)

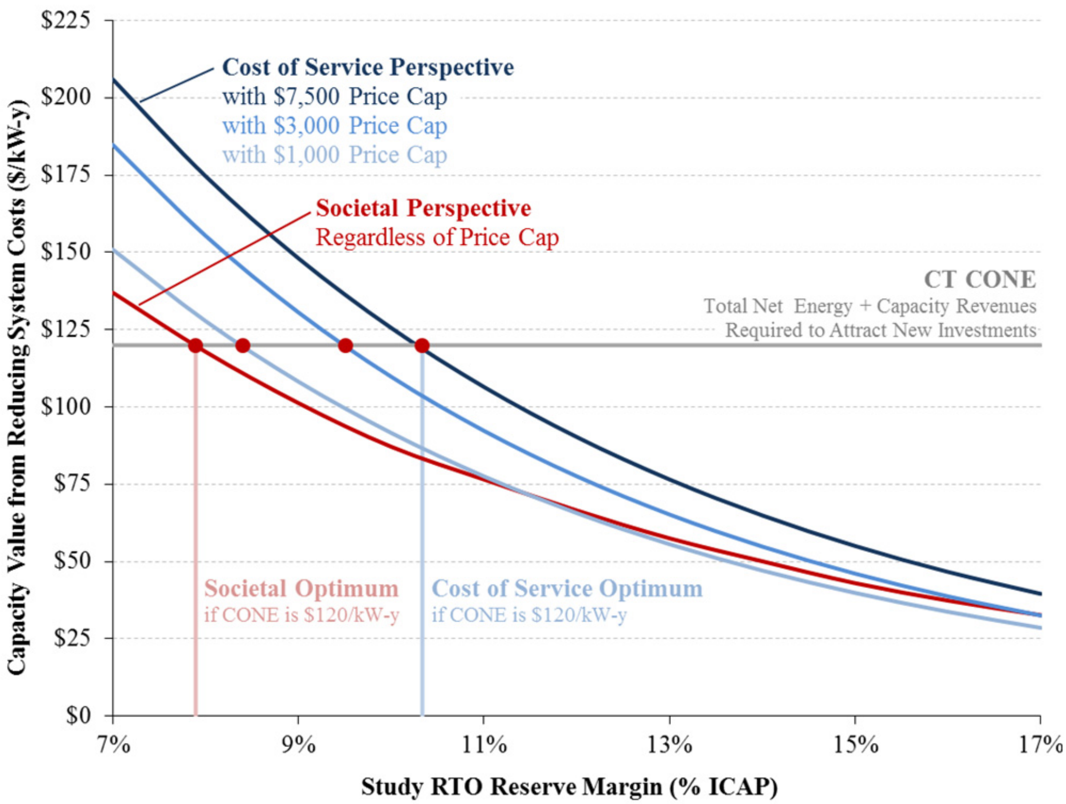


Notes:
Base Case reliability-related costs from a risk-neutral, cost-of-service perspective, see Section III.A.2.

The fact that the economically-optimal reserve margin depends on CONE suggests that administratively-determined reserve margin requirements should also vary with CONE. In other words, it would be more efficient to maintain a higher reserve margin if additional capacity can be added at relatively low cost. Similarly, mandated reserve margins should be lower if new capacity is expensive. This economically-efficient approach to procuring capacity could be achieved in either cost-of-service regulated power markets or deregulated regions within a capacity market. It would require: (a) estimating the incremental value of capacity using probabilistic economic and reliability simulations (as we have done for the hypothetical Study RTO); and (b) comparing that value against the total cost of procuring capacity, which may be unknown in advance.

Figure 35 shows the value of incremental capacity as a function of reserve margins. We calculate the incremental capacity value as the reduction in total system costs (excluding capital costs) that would be achieved by adding incremental capacity. As the figure shows, this incremental value of capacity also depends on whether one applies a cost-of-service or societal perspective for calculating total system costs. We thus show capacity values for: (a) a risk-neutral, cost-of-service perspective in a system with a price cap at the $7,500/MWh VOLL, as well as at the lower price caps of $3,000/MWh and $1,000/MWh; and (b) a risk-neutral societal perspective. The value of capacity is a function of price caps only under a cost-of-service perspective, because the lower price caps (which are applied in both Study RTO and neighboring regions) will reduce the cost of procuring emergency imports. From a societal perspective, however, the value of capacity does not depend on energy prices. It depends only on internal and external production and reliability-related costs, not on the market prices themselves.

Figure 35
Reduction in Expected System Costs Achieved by Adding Capacity
(Excluding the Carrying Costs Required to Build the Incremental Capacity)



Notes:

Capacity value is the reduction in system costs (excluding capital costs) achieved per unit of capacity added.

Cost-of-Service costs are calculated for the Base Case as well as the $3,000/MWh and $1,000/MWh price cap cases from a risk-neutral cost-of-service perspective as in Section III.A above. Societal costs are calculated for the Base Case on a risk-neutral basis as in Section III.A.3 and do not vary with price cap levels.

Plotted with x-axis based on the Study RTO internal reserve margin. Note that the 7.9% "socially optimum" reserve margin in the Study RTO is equivalent to a 16.5% reserve margin across all systems' coincident peak loads, as explained in Table 7 in Section III.A.3.

Any time the incremental value of capacity (shown as downward-sloping lines), exceeds the incremental cost of new capacity, it would be efficient to procure more capacity. This comparison must consider the *total* procurement costs, including both capacity payments and net energy payments.[146] Figure 35 compares these value-of-capacity curves for our Study RTO to the Base Case CONE value of $120/kW-year. The value of capacity is equal to CONE at the risk-neutral, economically-optimal reserve margin as calculated previously and indicated with red dots in the chart. These optimum reserve margins would increase if CONE were lower, as discussed above.

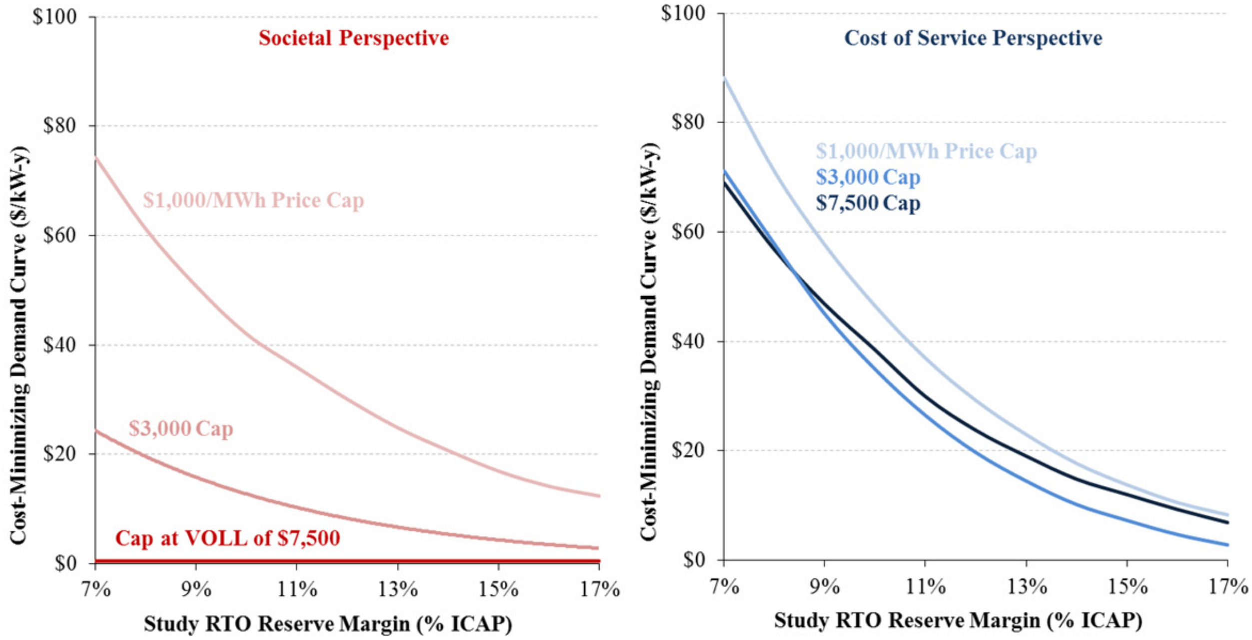
Within a capacity market, one can translate this value-of-capacity calculation into a cost-minimizing demand curve for capacity by subtracting out the portion of total costs that suppliers would be able to cover through energy margins as shown in Figure 36. This demand curve for capacity would procure the quantity of capacity needed to minimize total system production, reliability, and capital costs, as calculated on a risk-neutral basis. These demand curves would need to be shifted to the right if policy makers or RTOs wished to incorporate some risk aversion into their procurement levels as discussed in Section III.A.4 above. Note, however, that the risk mitigation preferences of suppliers and customers might alternately be resolved through market-based hedging and forward contracting, at least in efficient and competitive markets with liquid futures markets and forward contracting opportunities.

The cost-minimizing demand curve from a societal perspective (left chart) is zero at all reserve margins in our Base Case where the price cap is set at VOLL. This is because, under the special circumstances of having perfectly efficient energy market prices, the energy-only market will be sufficient to attract the efficient quantity of capacity investments from a societal perspective as explained in Section IV.A.2. However, if the price cap is below VOLL or energy prices are otherwise suppressed, it would be efficient to procure additional capacity through a capacity market. The lower the price cap and the greater the price suppression, the higher the capacity demand curve would need to be to procure the socially-optimal quantity.

From a risk-neutral cost-of-service perspective (right chart), the cost-minimizing demand curve is also a downward-sloping function with a very similar shape. As the chart shows, however, the height of the demand curve is not as directly related to the price cap as is the case for the socially-optimal demand curves. This is because the value of capacity is partly tied to the suppression of energy prices and associated reduction of net import costs. With a lower price cap, the value of higher reserve margins on reducing import costs is less (lowering the demand curve) but the effect is offset because suppliers' energy margins would also be reduced (increasing the demand curve). These offsetting factors result in a demand curve that is not as heavily impacted by the price cap.

[146] In the context of a region with a capacity market, the total payments would be the sum of energy margins and capacity payments based on the market prices for energy and capacity. In a regulated utility setting with PPAs, the total procurement cost would be net energy payments plus capacity payments under the PPA, which may be broken down in various ways depending on contract terms.

Figure 36
Risk-Neutral, Cost-Minimizing Demand Curve for Capacity



Notes:
Calculated as the value of capacity from Figure 35 minus the energy margins from Figure 26.

4. Current RTO Demand Curves Compared to Cost-Minimizing Curves

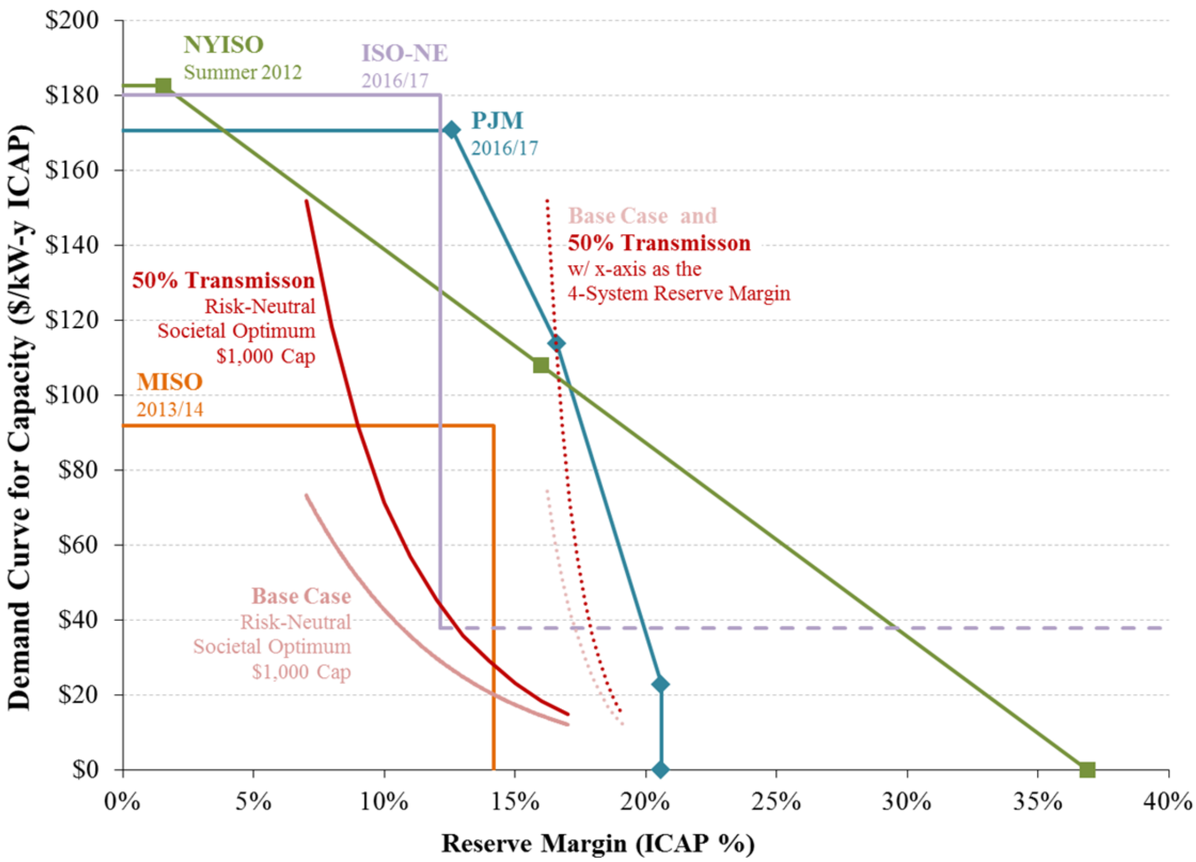
Figure 37 compares the cost-minimizing demand curves calculated in the previous section to demand curves that are currently being used in the capacity markets in NYISO, ISO-NE, PJM, and MISO. We compare the demand curves that would be calculated under the Base and 50% Transmission Cases from the risk-neutral societal perspective under a $1,000/MWh price cap. We selected these cases to compare because we believe that these two simulation cases may most closely resemble these various real-world RTOs, but stress that the value-based demand curve would be quite different if estimated for any particular region.

We plot the curves in two different ways: (1) with the x-axis defined as the Study RTO's reserve margin compared against the Study-RTO non-coincident peak load (solid lines); and (2) with the x-axis defined as the combined four-system reserve margin against the combined systems' coincident peak load (dotted lines). Further, we note that these risk-neutral demand curves would have to be shifted to the right if policy makers or RTOs wished to incorporate risk mitigation benefits into the demand curves.

Not surprisingly, the cost-minimizing demand curves from a risk-neutral societal perspective have lower prices than the actual RTO demand curves when compared against the Study RTO reserve margin. This is primarily because these actual RTO demand curves were developed with the objective of achieving the 0.1 LOLE standard, while a risk-neutral societal approach would aim to procure a lower reserve margin and reliability level under our study assumptions. Actual RTO demand curves also reflect a number of other objectives and real-world considerations such as: (a) the objective of mitigating capacity price volatility; (b) the practical difficulties of administratively estimating demand curve parameters, including the approximate Net CONE at the target reserve margin; and (c) the difficulty of building consensus on a capacity demand curve's shape, given the multitude of stakeholders with disparate and competing interests that are involved in such market development efforts.

While U.S. RTOs with capacity markets and their regulators have not yet demonstrated substantial interest in considering such a value-based approach to estimating demand curves (whether risk-neutral, or risk-adjusted), we note that Italy will soon implement a capacity market with a value-based demand curve that is at least conceptually similar to the approach that we have outlined in the previous section.[147]

Figure 37
Cost-Minimizing Capacity Demand Curve vs. Current RTO Demand Curves



Sources and Notes:

All curves converted from source units into ICAP terms for both reserve margin and price.

Cost-minimizing demand curves plotted with x-axis as: (1) the Study RTO reserve margin against Study-RTO non-coincident peak load (solid lines); and (2) against the combined four-system reserve margin against the combined coincident peak load (dotted lines). See Table 7 in Section III.A.3 for a more detailed explanation of this coincident vs. non-coincident reserve margin accounting convention.

See ISO-NE (2013); MISO (2012c, 2012d); NYISO (2013); PJM (2013a).

[147] Italy's system operator Terna has submitted its proposal for calculating this value-based demand curve, as briefly outlined in Terna (2012), Sections 2.3-2.4.

C. IMPLICATIONS OF INCREASED DEMAND RESPONSE PENETRATION

Section IV.C examines the system cost and reliability implications of increasing levels of demand response penetration, assuming that increasing DR resources would displace traditional generation. Increasing DR penetration also has a number of important implications for energy and capacity market outcomes. Namely, as DR penetration increases and displaces generation resources, it will: (1) cause the energy supply curve to shift upward because lower-dispatch-cost CTs are being replaced by DR with higher dispatch cost, resulting in higher energy prices during peak load and scarcity conditions; (2) increase average generator margins due to the higher peak energy prices; and (3) reduce capacity market prices by increasing generators' energy margins. We discuss these and related implications for market design in the following sections, and evaluate the relevance of these results to PJM's market, which is the U.S. market that will be relying most heavily on DR resources over the coming years.

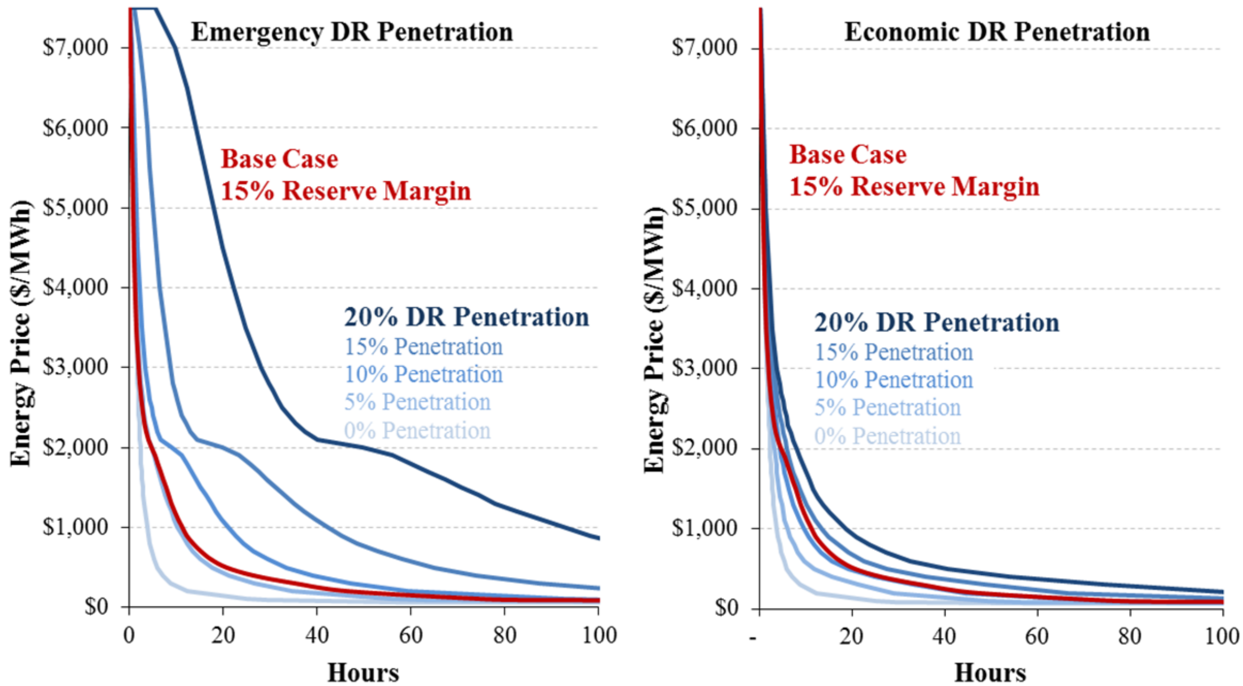
1. Energy Market Impacts

As DR penetration increases, it will displace traditional generation resources if the reserve margin requirement remains fixed. This will increase the supply curve and realized prices in the energy market, because lower-dispatch-cost generation resources will be displaced by higher-dispatch-cost DR. If that DR is primarily "emergency" rather than "economic" DR it will have an even greater impact on the energy market because: (1) emergency DR is available only during emergency conditions (at a high strike price of $2,000/MWh assumed in our simulations), while economic DR is available over a wide range of dispatch prices, including a portion that is available at relatively low dispatch prices (a few hundred dollars in our simulations); and (2) emergency DR is a dispatch-limited resource (in our simulations it can only be dispatched up to 100 hours per year), resulting in even higher energy prices during any years when the dispatch limit is exceeded.

Figure 38 illustrates these impacts by showing the price duration curve for the Base Case simulations and a 15% planning reserve margin and varying market penetration levels for emergency DR (left chart) and economic DR (right chart). For comparison, we also show the price duration curve from the Base Case simulations at the same 15% reserve margin.[148] The distinction between emergency and economic DR is not particularly important at relatively low penetration levels of up to 5% (similar to historical experience), because the frequency with which the DR resource will be dispatched is quite low at these penetration levels. As explained in Section III.C.1 above, at the 5% penetration level, one would expect few or no DR calls in years with typical weather. However, with higher levels of DR penetration (darker blue lines), the entire price duration curve is shifted up, with the increase being substantially larger if the DR resources consist only of dispatch-limited emergency DR rather than economic DR.

[148] Recall that the Base Case simulation has a 6.9% DR penetration level, with DR resources consisting of 80% emergency DR and 20% economic DR.

Figure 38
Energy Price Duration Curve with Increasing DR Penetration
(Average Year Results at Fixed 15% Reserve Margin)



Notes:

The average price duration curve at 15% reserve margin and varying levels of Emergency (left) or Economic (right) DR penetration.

In our simulations, the high reliance on Emergency DR also has the effect of creating a "shelf" in the price duration curve at the assumed emergency DR strike price of $2,000/MWh.[149] The shelf in energy market prices is an artifact of the high-dispatch-cost nature of Emergency DR. Emergency DR implicitly assumes that all DR resources are identical and that the underlying DR resources all have the same strike price. In reality, however, every individual DR asset will have its own strike price that could be above or below the $2,000/MWh assumed in our simulations. Indiscriminately dispatching Emergency DR assets as if they had a uniform strike price will have the problematic effect of calling on DR resources with high strike prices of several thousand dollars, when lower-cost economic DR and non-DR resources would likely be available. Additionally, DR resources with a strike price of only a few hundred dollars would prefer to be interrupted much more frequently by customers trying to avoid high energy prices.

The Economic DR penetration simulation cases demonstrate generally preferable outcomes. Integrating high-levels of Economic DR results in a smoother, better-behaved price duration curve with no artificial "shelf" caused by an administratively-determined Emergency DR strike price level. This illustrates the efficiency gains from integrating economic DR resources into wholesale markets, whether they are directly dispatchable by the system operator or only

[149] Note that the shelf is somewhat smoothed by the fact that the plots show the average price duration curve over many simulation runs. In any individual run or delivery year the shelf would be an even more prominently "blocky" feature of the emergency DR curve.

responding to market prices. The market is more efficient overall because each DR resource has self-selected its own level and price of curtailments. For example, end users place relatively little value on service for at least a portion of their total load may respond to energy market prices and curtail demand at a relatively low strike price of $500/MWh. In our simulations, this DR resource would be curtailed approximately 40 times per year (or less than one hour per week) in the 20% penetration case, an interruption frequency that many end users may find acceptable for non-essential uses.[150]

To date, the consequences of relying heavily on Emergency DR have not yet been a major concern because Emergency DR is rarely, if ever, dispatched in most systems. This is because: (a) many U.S. systems have had modest DR penetration levels of only 6% to 7%; (b) many U.S. RTOs have an surplus generation capacity, which means Emergency DR would rarely be called even if the system had a high DR penetration level; and (c) energy prices are capped and rarely exceed a few hundred dollars in most systems, meaning that only DR resources with the very lowest strike prices have had any reason to participate in the energy market.

This will change over the next years however, particularly in PJM, where high levels of DR have displaced generation for the next several delivery years. This will cause a substantial increase in DR dispatch over the coming years.[151] Historically, and consistent with our Base Case assumptions, 80% of PJM's DR assets have participated as emergency-type DR, while only 20% participated in the energy market. It seems very likely that, as energy prices and DR dispatch hours increase over the coming years, more DR will begin participating in the energy market because there will be increasingly more hours during which the "true" strike price of lower-cost DR resources will be exceeded.[152] Resources with very high strike prices will not opt to participate directly in PJM's energy market, however, because: (a) their strike prices may exceed the energy price cap, in which case they would never wish to be interrupted; or (b) their number of call hours is too low, so that the benefits of participating in the energy market would not justify the infrastructure or overhead costs of direct market participation.

2. Impact on Generator Energy Margins

Consistent with the increase in energy prices caused by displacing generation with DR resources, generator energy margins would increase as shown in Figure 39. The figure shows the average annual energy margins (red) as a function of DR penetration, along with the annual margins expected in the median year (blue), middle 50% of years (dark gray), and middle 90% of years

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150 However, even very high interruption rates may be tolerable if managed within a portfolio of resources by a DR aggregator, because an aggregator could limit the interruption rate of any individual DR asset by maintaining a high quantity of DR assets that exceeds its curtailment obligation under any one event.

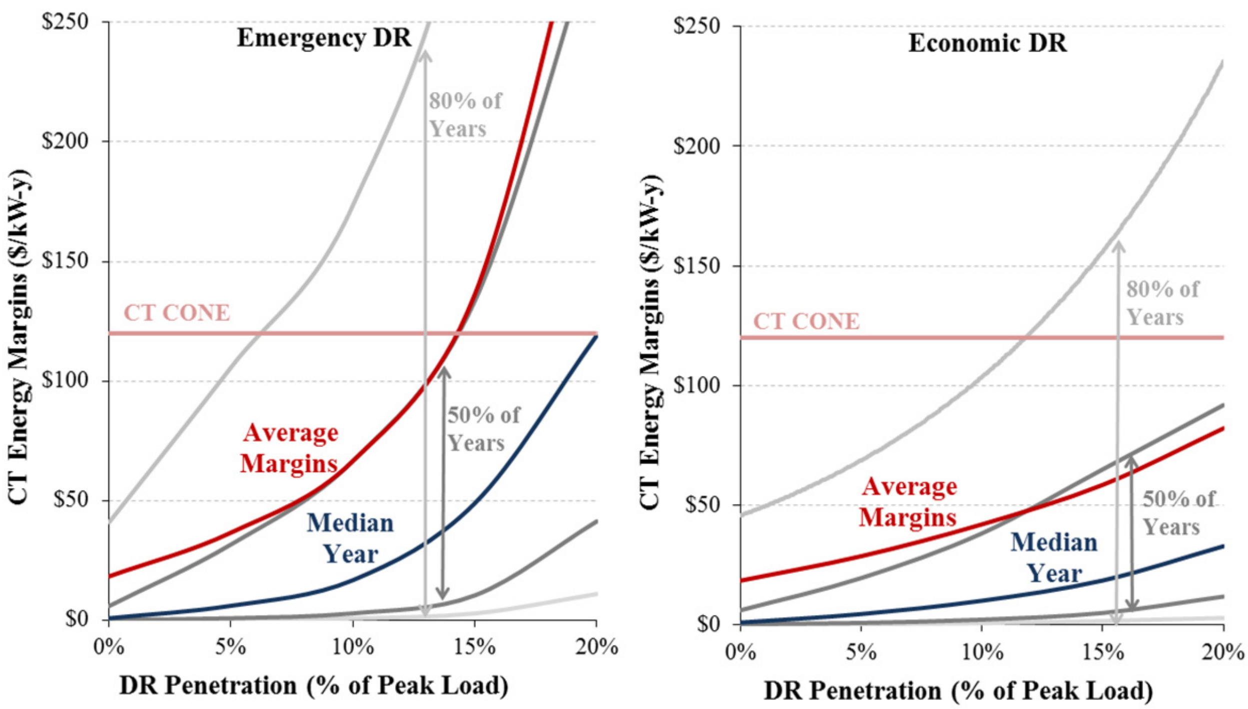
151 For an analysis of how DR displacing generation may increase DR call hours in PJM over the coming years, see Newell and Spees (2013).

152 DR may participate directly by offering hourly bids into the energy market or, possibly more commonly for resources that wish to avoid the substantial effort required to submit hourly energy bids into the nodal market, these assets may submit a single energy strike price that is applicable all year and that would be used with slightly less locational dispatch precision. For an overview of PJM's new scarcity pricing mechanism, including its approach to incorporating emergency and economic DR into price-setting, see PJM (2012b).

(light gray). Consistent with the observations about energy price impacts, relying more heavily on Emergency DR will increase generator energy margins more quickly than relying more heavily on Economic DR. Again, this is because Economic DR will offer into the energy market at a large range of prices, including at some relatively low prices of only a few hundred dollars.

The smoother and better-behaved price formation associated with Economic DR also translates into substantially less volatility in year-to-year spot energy margins earned by suppliers. With Emergency DR, the 100 hour call limit and energy price "shelf" at the assumed administratively-set level of $2,000/MWh result in a much larger difference in energy margins between moderate years (with few or no DR calls) and extreme years (with many DR calls all at the same high price). At the 15% Emergency DR penetration level, our simulations result in spot-market-based energy margins of $48/kW-year (41% of CONE) for the typical year but up to $334/kW-year (2.8 times CONE) once per decade. In comparison, CTs would experience lower (but much less volatile) energy margins in a market with 15% Economic DR penetration. For that case, our simulations yield spot energy margins of $18/kW-year (15% of CONE) for the typical year and as high as $152/kW-year (1.3 times CONE) once per decade.

Figure 39
Volatility in Energy Margins vs. Emergency DR (left) or Economic DR (right) Penetration
(Fixed 15% Reserve Margin)



Notes:
CT energy margins in the Study RTO when displacing CTs with increasing levels of DR penetration.
Gray lines represent the 10th, 25th, 50th, 75th, and 90th percentile estimates of energy margins.

3. Impact on Capacity Market

The increase in energy margins with higher DR penetration will also have the long-run effect of decreasing equilibrium capacity prices, because total generator net energy and capacity revenues will have to equal CONE on average as explained in Section IV.B.1 above. This consequence is demonstrated in Figure 40 that shows the equilibrium capacity price at a 15% reserve margin with increasing Emergency DR penetration, increasing Economic DR penetration, and under our Base Case simulation.

Capacity prices are the same with Emergency and Economic DR at the 0% penetration level, and decrease more quickly in the Emergency DR Case because energy market prices increase more quickly.[153] In fact, at approximately 14% Emergency DR penetration, the capacity market price would be driven all the way to zero, with energy prices so high that traditional generators would be willing to build even if they had no capacity payments. Obviously, this outcome is economically infeasible because Emergency DR providers would need a capacity payment that is at least high enough to pay for their fixed annual costs and expected net interruption costs.[154] In other words, if only Emergency DR existed, then the capacity market would converge to an equilibrium DR penetration level somewhere below 14%.[155]

If only Economic DR existed and at the quantities that we assume can actually be realized, then capacity prices would drop with increasing penetration levels but would not drop to zero over the penetration levels we examine. In that case, DR penetration would level off at the fixed costs of maintaining DR minus the net value of participating in the energy market.[156] We do not attempt to quantify that equilibrium penetration level for our purposes, but note that the fixed costs of adding more DR will necessarily increase at higher penetration levels as the lowest-cost DR

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153 Note that in a real-world capacity market the difference between the Emergency and Economic DR Cases might be somewhat smaller because the RTO is likely to reduce the capacity credit awarded to Emergency DR at high penetration levels as it becomes obvious that the call-limited Emergency DR is providing substantially lower reliability value. This would mean that the Emergency DR would displace somewhat less generation capacity than the Economic DR, which would somewhat reduce the impacts on energy market prices, CT energy margins, and capacity margins.

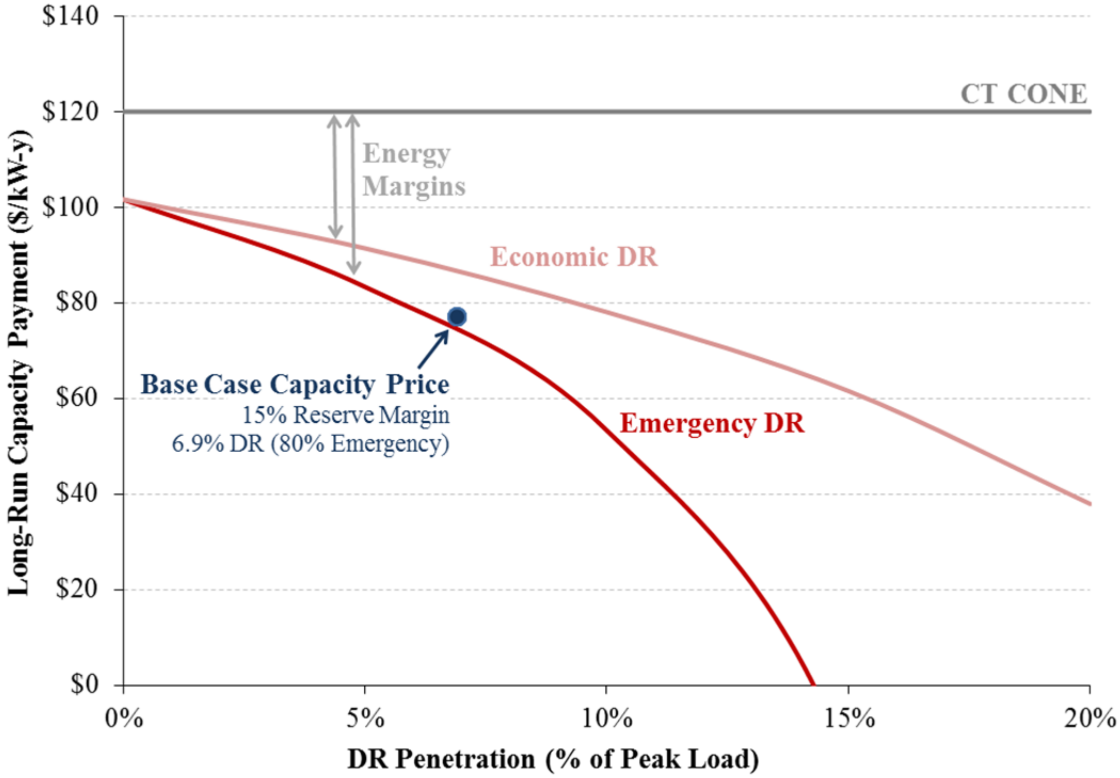
154 Note that DR suppliers have an annual "net interruption cost" that would be calculated very similarly to generator energy margins but can actually be positive or negative in total value. The value of the "net interruption cost" is the energy price when called minus the true strike price. If the energy price when called exceeds the DR asset's true strike price then the interruption provides positive value to the DR supplier, who avoids paying energy prices in excess of their private value (note that for Economic DR the energy price always exceeds the true strike price when called and so participating in the energy market would always create positive value). In the alternate case when the energy price is below the DR asset's true strike price, the interruption will impose a net cost on the DR supplier. For example, if a DR asset's true strike price is $5,000/MWh, but the energy market price cap is $1,000/MWh (or the administratively-determined Emergency DR strike price is $2,000/MWh), then every interruption would impose a net cost.

155 Penetration levels of Emergency DR would also be limited by the fact that call-limited DR has lower capacity value and would probably therefore be assigned lower capacity payments at these high penetration levels. PJM has already implemented such a mechanism for differentiating capacity payments among call-limited and unlimited DR products. For an explanation and discussion of PJM's multiple DR products, see Pfeifenberger, *et al.* (2011a), Section VI.C.1.

156 See footnote 154 for an explanation of the net value that a DR asset would earn in the energy market.

resources are already committed and only higher-cost DR options remain available for incremental procurement.

Figure 40
Equilibrium Capacity Prices with Increasing Levels of DR Penetration
(Fixed 15% Reserve Margin)



Notes:
Equilibrium capacity price is at CT Net CONE.

In real markets, most DR is currently Emergency DR, suggesting capacity and energy market impacts more similar to the Emergency DR case at low penetration levels. For example, in PJM approximately 80% is Emergency DR while approximately 20% is Economic.[157] However, as total DR penetration levels increase, we believe it is likely that a greater proportion of DR will begin to participate in the energy market, driven by increasing energy prices as explained in Section IV.C.1. However, some Emergency DR will never migrate into the energy market because energy market prices would so infrequently exceed their true strike price (or may never exceed their true strike price if the energy market cap is far below VOLL).[158] In other words, it is still plausible that even with a price cap that is somewhat below the likely VOLL, the

[157] See PJM (2013c), p. 5.

[158] Emergency DR would only migrate into the energy market if the net value of participating in the energy market exceeds the increase in fixed infrastructure and administrative costs incurred.

combination of PJM's energy and capacity markets may be able to attract a relatively efficient portfolio of Economic and Emergency DR.[159]

D. COMPARISON OF CAPACITY AND ENERGY-ONLY MARKET DESIGNS

This section of our report provides a high-level comparison of realized energy and capacity prices, supplier net revenues, and customer costs under alternative energy-only and capacity market designs. We also compare simulation results with varying price caps and target reserve margin levels. These results reflect realized prices and costs under a restructured energy-only or capacity market in which suppliers earn market-based revenues to recovery their fixed costs and customers pay market prices for energy and capacity.

1. Supplier Net Revenues

Figure 41 shows supplier net revenues (*i.e.*, total market-based revenues less operating costs) for a new CT from energy margins and capacity payments under the Base Case simulation over a range of reserve margins.[160] As explained previously, in a restructured wholesale energy-only or capacity market, supplier net revenues must be equal to the fixed costs at CONE to sustain the investment needed for a particular equilibrium reserve margin. Under our simulations, we estimate 7.9% equilibrium reserve margin for the energy-only market design. At this equilibrium reserve margin, suppliers would earn net revenues that fully recover their investment and earn sufficient returns in the energy market. Policy makers would have the option to require a higher planning reserve margin, but doing so would necessitate a resource adequacy requirement that creates additional compensation through bilateral or centralized capacity markets. In the following discussion we focus on energy-only and centralized capacity market designs.[161]

As planning reserve margin requirements increase, energy margins will decrease. This means that the proportion of supplier net revenues from capacity payments—needed to avoid under-investment due to "missing money"—will increase at higher reserve margins. Capacity payments will, for example, need to cover more than 70% of CONE at the 17% reserve margin. For intermediate and baseload units, capacity revenues would be the same but represent a lower fraction of net revenues because those resource types would earn higher energy margins and have higher fixed costs.

In other words, in equilibrium, supplier net revenues are the same in energy-only and capacity market designs and cover the long-run marginal cost of supply. However, the proportion of net

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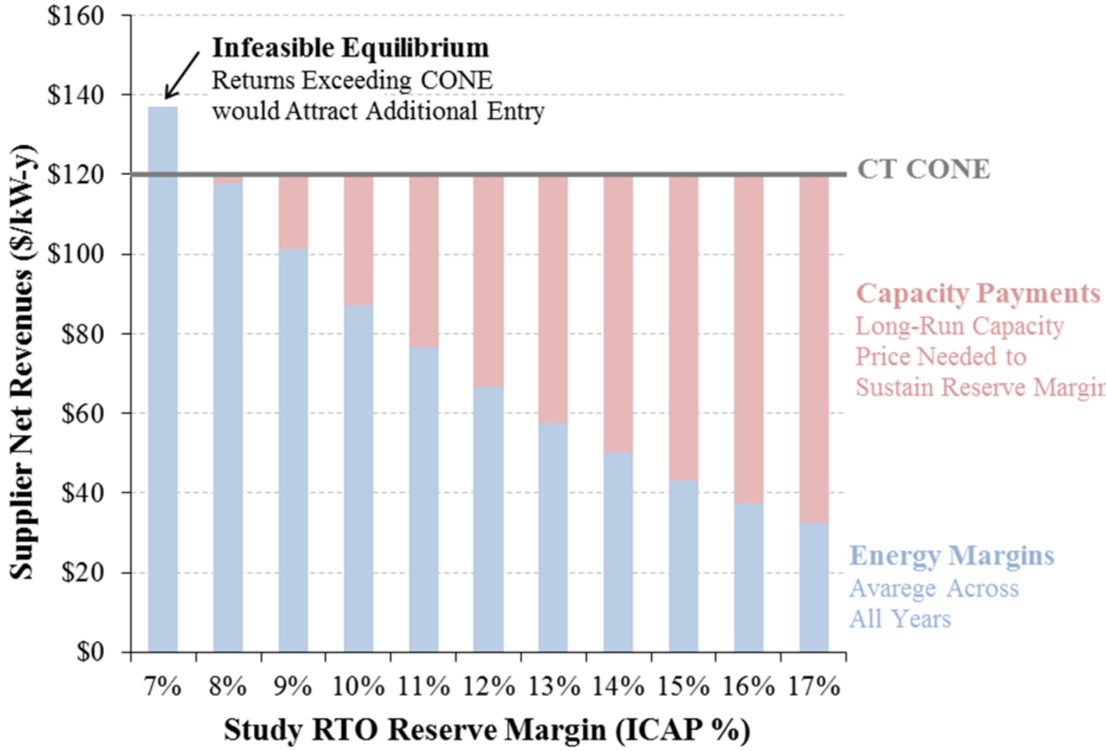
[159] With the primary inefficiency stemming from the lack of an efficient call order among resources whose strike price is near to or exceeds the energy market cap. PJM's current cap on the energy component of the LMP is $1,500/MWh,as of October 2012 and will rise to $2,700/MWh by June 2015, see PJM (2012b), p. 162.

[160] Average energy margins and capacity prices are calculated as explained in Sections IV.A.1and IV.B.1 above respectively.

[161] While other approaches to achieving higher planning reserve margins exist, we focus here only on energy-only and capacity market approaches for simplicity. For a broader discussion of alternative approaches, see Pfeifenberger, *et al.* (2009); and Spees, *et al.* (2013).

revenues from the energy and capacity markets is quite dependent on market design, reserve margin requirement, and other fundamentals that affect energy market prices. The proportion of supplier returns from the energy and capacity markets can also have substantial implications if one or the other of these markets is particularly exposed to regulatory risks or inefficiencies as discussed above. Further, any inefficiency in the capacity or energy only market designs could result in attracting or maintaining an inefficient mix of baseload, intermediate, and peaking resources.

Figure 41
Supplier Net Revenues as a Function of Planning Reserve Margin Requirements



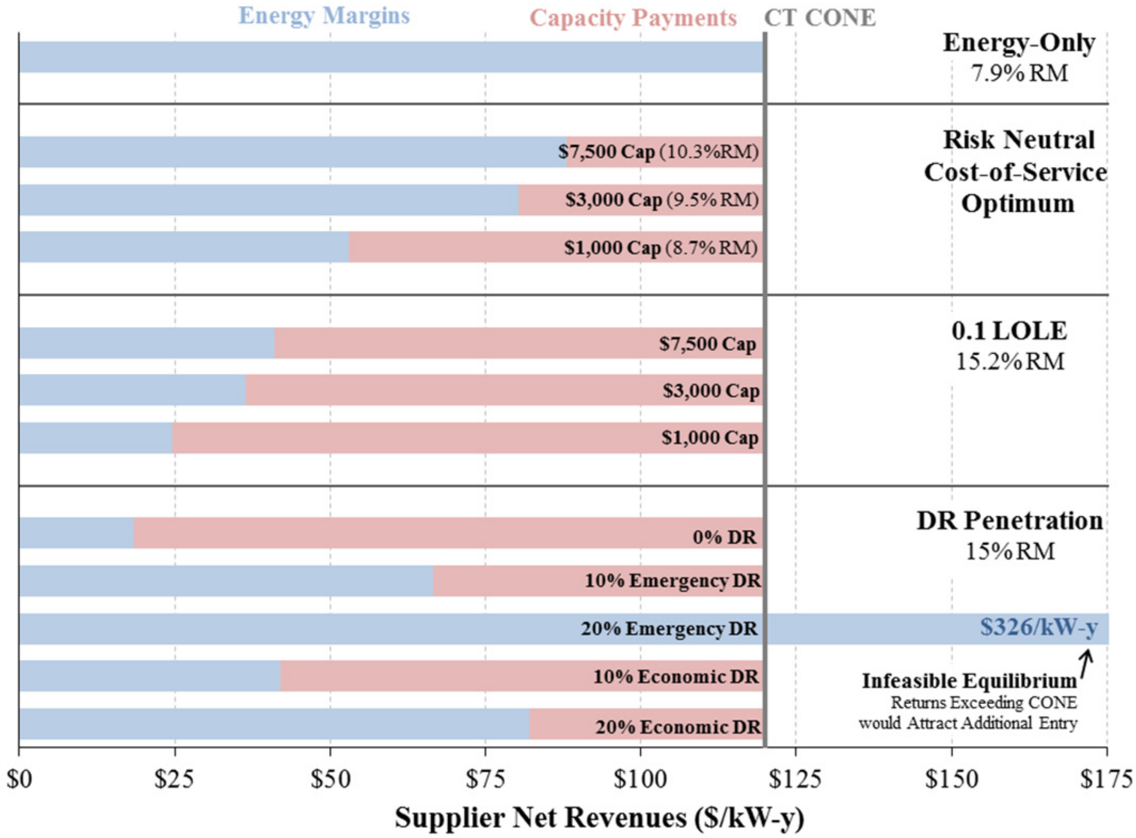
Notes:
Study RTO Base Case results, see Sections IV.A.1and IV.B.1 for calculation details.

Figure 42 similarly shows supplier net revenues from energy and capacity markets under different market designs, price caps, reserve margin targets, and DR penetration levels. Again, note that, to be able to attract investment, supplier net revenues are always equal to CONE in equilibrium, although the proportion from capacity versus energy margins varies with design.[162] The figure shows that a capacity market with a planning reserve margin requirement set at the risk-neutral, cost-of-service optimum would require that suppliers earn 27% to 56% of their net revenues from the capacity market (depending on the price cap), while the capacity market with a reserve margin requirement based on the 0.1 LOLE standard would require that 66% to 80% of

[162] Also note that the case with energy margins exceeding CONE indicates a disequilibrium that would attract more supply until reserve margins increased enough to decrease supplier net revenues until they equal CONE.

net revenues are earned in the capacity market. With higher levels of DR penetration, generation suppliers would earn a greater portion of their net revenues in the energy market.

Figure 42
Supplier Net Revenues Under Different Market Designs and System Conditions



Notes:
Study RTO results for Base, Price Cap, and DR Penetration Cases.

2. Total Customer Costs

Figure 43 shows the annual average of total customer costs as a function of planning reserve margin in the Base Case simulation, including transmission and distribution, energy, and capacity costs.[163] Note that T&D costs do not change with the reserve margin, while energy costs decrease and capacity costs increase, consistent with the trends in market prices discussed above. The directional change in the proportion of customer costs incurred for energy and capacity are similar to the directional changes in supplier returns for the marginal CT, but the magnitudes are different because: (a) customer costs reflect total energy costs not just the above-cost portion represented by energy margins; and (b) customer costs reflect total energy and capacity payments to all types of resources other than just the marginal CT including

[163] T&D costs are based on a national average, from EIA (2013b).

intermediate and baseload resources whose total returns are more focused on energy than capacity.[164]

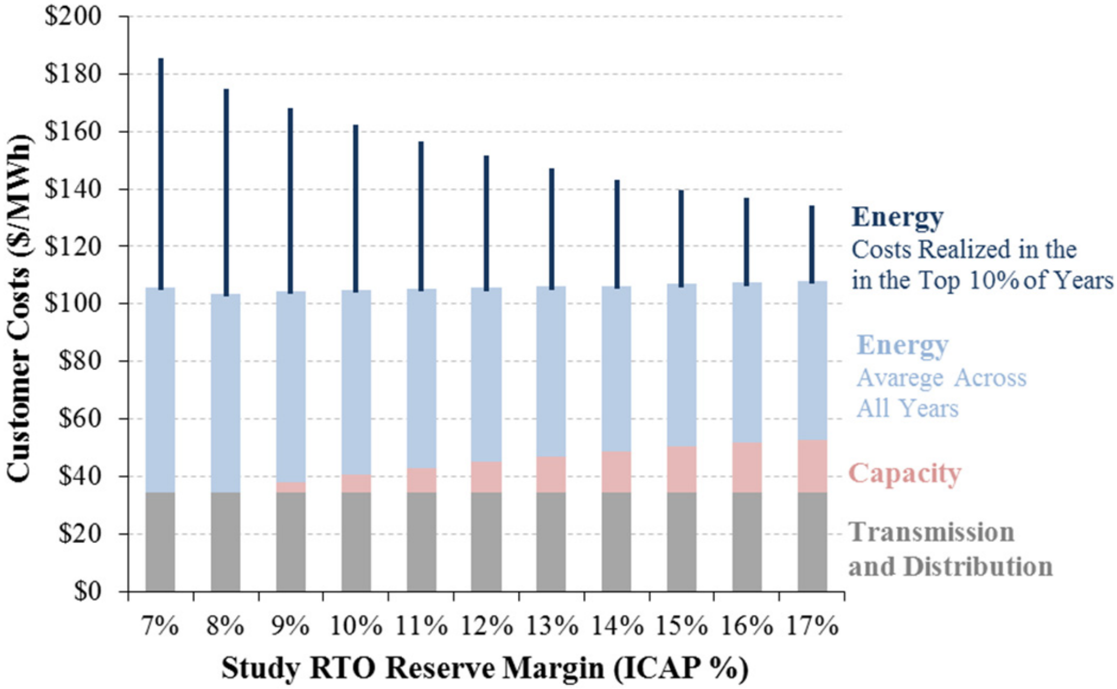
Total customer costs are minimized at the risk-neutral, "societally-optimal" reserve margin of 7.9%, consistent with the discussion in Section IV.A.2 above. Unlike individual suppliers' equilibrium net revenues, customer costs vary with the reserve margin even in equilibrium conditions. This is because the total system cost increases with planning reserve margins and the total generation base that must earn sufficient net revenues increases. However, the increase in total customer costs with reserve margin is quite small as a percent of total costs, making the increase difficult to see when total costs are shown to scale. In fact, increasing the reserve margin above the risk-neutral, societal optimum of 7.9% to the 15.2% reserve margin needed under the 0.1 LOLE standard increases average customer costs by $1.63/MWh or only 1.5%.

Importantly, we note that the incremental customer cost imposed by implementing a capacity market relative to an energy-only market cannot be calculated simply by estimating the final capacity price and multiplying by the procured quantity. This is because increasing the reserve margin with a capacity market not only introduces capacity costs but also reduces energy-related costs, a factor which is not considered in many discussions.

Figure 43 is also useful for answering the deceptively simple question of whether energy-only or capacity markets are more expensive for customers. The real answer is that total customer costs have less to do with energy-only versus capacity market design, but more to do with the equilibrium reserve margin. Whether through energy-only or capacity market design, total capacity costs must be sufficient to cover the capital and operating costs of the fleet in expectation. The exact reserve margin achieved depends on market design details, with: (a) the capacity market reserve margin determined by the planning reserve margin target, and (b) the energy-only market reserve margin determined by the level of market prices (which may be higher or lower than the "optimum" depending on whether energy prices are more often above or below the perfectly efficient level).

[164] However, in a true, perfect equilibrium, the Net CONE of all resource types would be equal even though energy margins will be different. See Section IV.A.2 for additional discussion.

Figure 43
Total Customer Costs and Spot Market Exposure for Different Planning Reserve Margins



Notes:
Study RTO Base Case results, with customers paying market prices for energy and capacity.
Sensitivity bars shows annual customer cost averaged for 10% of the most expensive years, assuming full exposure to spot energy market uncertainty (*i.e.*, no LSE risk mitigation through seasonal or longer-term forward contracting).
Average T&D costs are a 2011 U.S. national average, see EIA (2013b).

This modest increase in average annual customer costs also achieves a risk mitigation benefit. As indicated by Figure 43, at the 7.9% planning reserve margin annual customer costs are likely to rise as high as $177/MWh once in ten years if those customers are fully exposed to spot market uncertainty.[165] This once-per-decade cost exposure is 68% higher than the average expected cost. At the higher 15.2% planning reserve margin, the once-per-decade spot market cost exposure is only $140/MWh, or 31% higher than the average. In other words, increasing planning reserve margins from 7.9% to 15.2% increases the average annual costs by $1.63/MWh but decreases the once-per-decade spot market cost exposure by $38/MWh or by approximately 36% of the total bill. As discussed earlier, however, this comparison will overstate the risk mitigation benefit of higher planning reserve margins because a large portion of all spot market uncertainties can be hedged readily by LSEs even on a relatively short-term basis, such as through forward contracting for an upcoming summer season.

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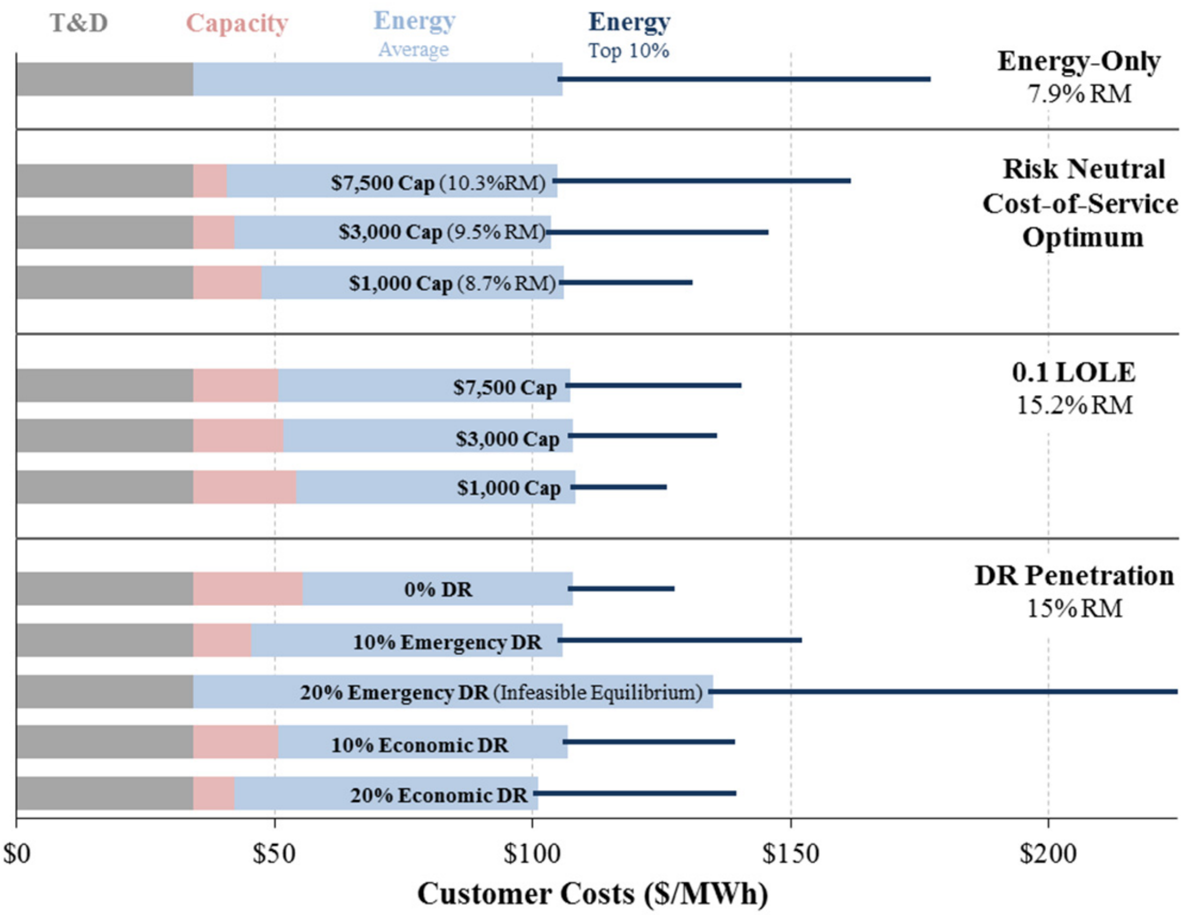
[165] This expected cost is calculated as the average expected cost of the top 10% of the most expensive energy price years, *i.e.*, the expected cost of the most extreme year in any particular decade. All percentages reported are calculated as a percent of the total customer bill in the average year at the 7.9% reserve margin.

Figure 44 similarly shows average customer costs and once-per-decade spot market exposure under different energy-only and capacity market designs, planning reserve margins, price caps, and DR penetration levels. Again, the directional changes in energy and capacity costs mirror the changes observed for supplier net revenues in the previous section. As noted above, the annual average of total customer costs can change by 1% to 2% under different planning reserve margins and price caps. However, an unhedged customer's exposure to high-cost years would be much higher at lower reserve margins, with higher energy market price caps, and with higher DR penetration levels (particularly if that DR is Emergency DR rather than Economic DR). Also note that average annual customer costs in our simulations are as much as 5% lower at a high 20% economic DR penetration level, due to the reduction in overall generating capacity needs in combination with lower capacity prices that would result if such a substantial resource base of relatively low-cost DR were available.

Figure 44
Average Annual Customer Costs for Different Market Designs and System Conditions



Notes:

Study RTO Base, Price Cap, and DR Penetration Cases results, with customers paying market prices.

Sensitivity bar shows annual customer cost averaged for 10% of the most expensive years, assuming full exposure to spot energy market uncertainty (*i.e.*, no LSE risk mitigation through seasonal or longer-term forward contracting).

Average T&D costs are a 2011 U.S. national average, see EIA (2013b).

V. CONCLUSIONS

As we more fully explain in the Executive Summary, this study documents a wide range of accounting and methodological conventions that make reserve margins and resource adequacy assessments very difficult to compare across regions. Regions that appear to adopt the same 1-in-10 resource adequacy standard may in fact apply very different standards. For example, we demonstrate that in a hypothetical system under identical methodological assumptions, the 1-in-10 standard may require a planning reserve margin anywhere from 8.2% to 19.2% depending on: (a) whether 1-in-10 is interpreted as 0.1 LOLE or 2.4 LOLH; and (b) whether only load-shedding constitutes a reliability event or whether voltage reductions and operating reserves shortages may also be classified as "events."

Relatively few North American regions currently evaluate the economic implications of their resource adequacy standards, with the exceptions being several entities in SERC. Evaluating the economics of resource adequacy standards is a difficult modeling challenge and involves a complex set of questions and tradeoffs among total cost, reliability, and risk of extreme events. However, unless these questions are explicitly evaluated, policy makers will not be in a position to make informed choices among their competing economic and reliability objectives.

In our illustrations for a hypothetical system, we show that, depending on how a regulator's economic objectives are defined, the "optimal" reserve margin may be 7.9% from a societal perspective, 10.3% from a cost-of-service perspective, or possibly higher if regulators incorporate risk mitigation benefits into their decision-making. In this and other studies, we demonstrate that the likelihood of extreme reliability and wholesale price spike events can be substantially mitigated by increasing reserve margins with only a modest increase in customer costs. For example, increasing the reserve margin from the 7.9% "socially optimal" level to the 15.2% required to maintain 0.1 LOLE increases customer costs by approximately 1.5%.

In implementing their resource adequacy objectives, policy makers may use a number of different planning or market-based approaches. We specifically evaluate the economics of resource adequacy under energy-only and capacity market designs. As has been theoretically discussed elsewhere, we demonstrate through our modeling results that a perfectly efficient energy-only market will achieve the socially optimal reserve margin in expectation. However, we caution that no market design is perfect and so energy-only markets may be susceptible to either: (a) under-investment, if wholesale prices are artificially suppressed by low price caps or insufficient administrative scarcity pricing measures; or (b) over-investment, if wholesale prices are kept artificially high by factors such as sustained exercise of market power. Further, even if an energy-only market achieves a socially optimal level of investments, it may or may not achieve other policy objectives such as maintaining resource adequacy as defined by the 1-in-10 standard.

If regulators of restructured power markets wish to maintain a reserve margin higher than what an energy-only market will likely support, they may implement a resource adequacy standard within a competitive capacity market. Under a capacity market design, system operators can achieve their resource adequacy target and suppliers will earn sufficient revenues from the capacity market to attract the desired level of new entry. This is true even if wholesale energy market prices may be artificially suppressed, for example during scarcity conditions.

Overall, average customer costs are not substantially impacted by market design in the long term, except to the extent that different market designs may sustain different reserve margin levels over the long term. Customer costs are much more heavily impacted by fundamental factors such as fuel prices, load shape, and the cost and mix of supply resources. In particular, incorporating substantial quantities of DR resources into wholesale capacity and energy markets can increase the efficiency of those markets and also reduce customer costs to the extent that substantial quantities of low-cost DR opportunities exist.

LIST OF ACRONYMS

1-in-10	One-Day-In-Ten-Years
AESO	Alberta Electric System Operator
APC	Adjusted Production Costs
APS	Arizona Power Service
APSC	Arizona Public Service Company
BPA	Bonneville Power Administration
CAISO	California ISO
CBM	Capacity Benefit Margin
CBO	Congressional Budget Office
CC	Combined Cycle
CEC	California Energy Commission
CEER	Council of European Energy Regulators
CONE	Cost of New Entry
CPUC	California Public Utilities Commission
CRS	Congressional Research Service
CT	Combustion Turbine
CVaR	Conditional Value at Risk
DR	Demand Response
EC	European Commission
EFORd	Expected Forced Outage Rate Data
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ENS	Energy-Not-Served
EOP	Emergency Operating Procedure
ERCOT	Electric Reliability Council of Texas
ETIP	Energy Technology Innovation Policy
EWITS	Eastern Wind Integration Transmission Study
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operations and Maintenance
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
GADS	Generation Availability Data System
GDP	Gross Domestic Product
GE-MARS	General Electric – Multi-Area Reliability Simulation

GEN	Generation
GTRPMTF	Generation and Transmission Reliability Planning Models Task Force
HR	Hour
ICAP	Installed Capacity
IESO	Independent Electricity System Operator
IRM	Integrated Resource Management
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	ISO New England
kW	Kilowatt
kW-y	Kilowatt Year
kW-yr	Kilowatt Year
kWh	Kilowatt Hour
KU	Kentucky Utilities Company
LFG	Landfill Gas
LGE	Louisville Gas and Electric Company
LOLE	Loss of Load Event
LOLEWG	Loss of Load Expectation Working Group
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
LTA	Long-Term Adequacy
LTRA	Long-Term Reliability Assessment
MAPP	Mid-Continent Area Power Pool
MARS	Multi-Area Reliability Simulation
MATS	Mercury and Air Toxics Standard
MIS	Mission: Integrated Systems (MIS Energy Management)
MMbtu	Million Metric British Thermal Units
MISO	Midcontinent, formerly Midwest, ISO
MW	Megawatt
MWh	Megawatt Hour
NEM	National Energy Market
NERC	North American Electric Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration
NPC	Nevada Power Company
NPCC	Northeast Power Coordinating Council
NREL	National Renewable Energy Laboratory
NRRI	Natural Resource Research Institute

NWPP	Northwest Power Pool
NYISO	New York ISO
NYSRC	New York State Reliability Council
PJM	PJM Interconnection
PNM	Public Service Company of New Mexico
PNW	Pinnacle West Capital Corporation
POLL	Probability of Lost Load
PPA	Power Purchase Agreement
PRISM	Parameter-Elevation Regressions on Independent Slopes Model
PRM	Planning Reserve Margin
PtP	Point-to-Point
PV	Photovoltaic
RES	Regulatory and Economic Studies
RFC	Reliability*First* Corporation
RM	Reserve Margin
RPM	Reliability Pricing MODEL
RTO	Regional Transmission Organization
RWG	Resource Working Group
SCE&G	South Carolina Electric & Gas Company
SCR	Special Case Resource
SERC	SERC Reliability Corporation
SERVM	Strategic Energy Risk Valuation Model
SoCo	Southern Company
SPP	Southwest Power Pool
SWIS	South West Interconnected System
T&D	Transmission and Distribution
TVA	Tennessee Valley Authority
UCAP	Unforced Capacity
USE	Unserved Energy
VOLL	Value of Lost Load
VOM	Variable Operations and Maintenance
WECC	Western Electricity Coordinating Council

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APPENDICES

In these appendices, we provide supplemental information underlying the general discussion regarding: (a) our survey of resource adequacy standards in place across North America, as summarized in Section I.C above; and (b) our simulation assumptions for analyzing the reliability and economic implications of resource adequacy, as summarized in Section II above. These details are provided in Appendices A and B respectively.

A. DETAIL ON SURVEY OF NORTH AMERICAN RESOURCE ADEQUACY CRITERIA

In this Appendix, we report additional detail from our survey of resource adequacy criteria used in U.S. and Canadian power systems, as summarized in Section I.C above. However, as noted above, to completely understand the nuances and complexities of these studies, one would need to discuss implementation details with the individuals responsible for implementing the studies. The public documentation of these studies is often insufficiently detailed or can easily be misinterpreted. Because we have not conducted such interviews to be able to document reliably the assumptions and the complexities of each study, our discussion should be interpreted as a summary of general industry practices, not a fully-verified documentation of any one region's approach.

1. Resource Adequacy Standards Used Across North America

Table 14 is a summary of resource adequacy standards across U.S. and Canadian power systems, as discussed in Section I.C.1 above.

Table 14
Survey of Resource Adequacy Criteria Across U.S. and Canadian Power Systems

Region	Standard	Model	Notes
PJM[a]	0.1 LOLE	PRISM and GE-MARS	The LOLE based target reserve margin and various other calculations provide key inputs into the PJM capacity market.
MISO[b]	0.1 LOLE	GE-MARS	Performed Annually by the ISO. Regional reserve margin of 16.7% but after diversity allows its load serving entities to carry an 11.3% reserve margin.
NYISO[c]	0.1 LOLE	GE-MARS	Resulted in a reserve margin of 16.1% for the period May 2012 to April 2013. Reserve Margin calculation includes nameplate of all resources including wind. Results are adapted to derated UCAP for implementation in the NYISO capacity market.
ISO-NE[d]	0.1 LOLE	GE-MARS	2012 ICR report calculates the requirement needed to meet its 1 day in 10 year standard, load uncertainty considers weather but not economic forecast error. Results used capacity market.
SPP[e]	2.4 LOLH	ABB Grid View	Capacity margin criterion of 12% for RTO members that are steam based and 9% for hydro based; results in capacity margin criterion above the 1 day in 10 year definition.
Maritimes [f]	20% RM and 0.1 LOLE	NPCC uses MARS	Maritimes uses a 20% reserve margin criterion for planning purposes but at the same time adheres to the NPCC requirement of not shedding firm load more than 1 day in 10 years.
Quebec[g]	0.1 LOLE	NPCC uses MARS	Based on an LOLE of 0.1, Quebec requires a 10% reserve margin for the 2012/2013 winter peak. By the 2015/2016 winter peak, Quebec requires a 12.2% reserve margin. Because of its dependence on hydro generation, Quebec also imposes an energy requirement to withstand 2 consecutive years of low water inflows.
IESO[h]	0.1 LOLE	NPCC uses MARS	The target for 2013 to meet the one day in 10 year target is 19.7% in which the region meets easily with an anticipated reserve margin of 40.1%.
Saskatchewan[i]	EUE Standard		Sask Power uses a 13% RM based on probabilistic analysis of Expected Unserved Energy.
Manitoba[j]	Both RM and energy standards due to hydro dependence		The energy criterion requires adequate energy resources to supply firm energy demand in the event that the lowest recorded coincident river flow conditions are repeated. The capacity reserve margin is at least 12%.
MAPP[i]	1 day in 10 years (LOLE of 0.1)		Some MAPP members self-impose a planning reserve margin of 15% based on the results of an LOLE study performed in 2009.
SERC/ General	No mandatory requirement		RA targets set by individual load serving members subject to regulatory review. With this approach, the criteria and final reserve margins vary across the region.
SERC/SoCo[k]	Economics	SERVM	The target is based on minimizing customer costs.

Region	Standard	Model	Notes
SERC/Duke Energy Carolinas[l]	0.1 LOLE and Economic Assessment	SERVM	Set minimum RM based on LOLE values but base target RM on an economic assessment, which is slightly higher than the LOLE target.
SERC/ Progress Energy Carolinas[m]	1 day in 10 years (LOLE of 0.1) and Economic Assessment	SERVM	Set minimum RM based on LOLE values but base target RM on an economic assessment, which is slightly higher than the LOLE target.
SERC/TVA[n]	Economics	SERVM	The target is based on minimizing customer costs.
SERC/Santee Cooper[o]	Economics	SERVM	The target is based on minimizing customer costs.
SERC/ LGE&KU[p]	Economics	SERVM	The target is based on minimizing customer costs.
SERC/ Entergy[i]	1 day in 10 years (LOLE of 0.1)	ERAILS	
SERC/ SCE&G[q]	12–18% RM		
FRCC[r]	0.1 LOLE	Tiger	"The FRCC has a resource criterion of a 15% minimum Regional Reserve Margin based on firm load. The FRCC assesses the upcoming ten-year summer and winter peak hours on an annual basis to ensure that the Regional Reserve Margin requirement is satisfied. Since the summer of 2004, the three Investor Owned Utilities (Florida Power & Light Company, Progress Energy Florida, and Tampa Electric Company) are currently maintaining a 20% minimum Reserve Margin planning criterion, consistent with a voluntary stipulation agreed to by the FPSC. Other utilities employ a 15% to 18% minimum Reserve Margin planning criterion."
ERCOT[s]	0.1 LOLE target (not mandatory)	Internal Model	ERCOT operates as an energy-only market and so does not mandate a RM; but performs one day in 10 year standard assessment to inform ERCOT and
WECC/ General[t]	No mandatory requirement		Individual balancing areas within WECC determine their own resource adequacy requirements in various ways and are subject to review by state regulators
CAISO[u]	15% RM		In January 2004, the CPUC established a long-term Resource Adequacy framework (D.04-01-050). This decision adopted a 15% to 17% planning reserve margin (PRM) and directed that each LSE is responsible for acquiring sufficient reserves to meet its own customer load. CAISO has since performed LOLE studies but the studies have not impacted the decision made in 2004 to maintain at a minimum 15% reserve margin
Northwest/ BPA[v]	Loss-of-Load Probability (LOLP) of 5%; and conditional value at risk (CVaR) to evaluate energy not served (ENS) events	Genesys Model	A completely different method from 1 day in 10 years. Method was developed in cooperation with the Northwest Council to take into account the predominantly hydro resource mix of the Northwest. For this use, LOLP is not defined as hours per year. It is instead a percentage of iterations that contain any EUE. The target allows no more than 5% of all iterations to contain EUE.
Southwest/ APS[w]	0.1 LOLE		APS 2012 IRP states that at 15% planning reserve margin criterion, LOLE is less than 1 day in 10 years.
Southwest/ PNW[x]	NM State Commission set target at 13%		Notes that reserve margin would likely increase if a one day in 10 year standard were used.
Southwest/ NV Energy[y]	1-in-10		Definition of 1 day in 10 years is not reported.
Alberta	No RA requirement		Intervention possible if expected EUE over a two-year outlook increases above 1,600 MWh.

Sources:

From regional resource adequacy studies: (a) PJM (2011); (b) MISO (2011); (c) NYSRC (2011); (d) ISO-NE (2011); (e) SPP (2010); (f) NBSO (2011); (g) Hydro-Québec (2011); (h) IESO (2012); (i) NERC (2011a); (j) Manitoba Hydro (2010); (k) Georgia Power (2010); (l) Duke (2012); (m) Progress (2012); (n) TVA (2011); (o) 2012 IRP, forthcoming; (p) LG&E and KU (2011); (q) SCE&G (2011); (r) FRCC (2012); (s) ERCOT (2012); (t) WECC (2011); (u) CPUC and CEC (2005); (v) BPA (2011); (w) APS (2012); (x) PNM (2011); and (y) Nevada Power (2012).

2. Illustration of Differences in Resource Adequacy Modeling Assumptions

Table 15 shows an illustrative comparison of select model assumptions as used in various regions' reliability planning studies, as discussed in Section I.C.3 above.

Table 15
Summary Comparison of Select Regions' Reliability and Resource Adequacy Studies

	ISO-NE	PJM	NYISO	MISO	SPP	SoCo
Reliability Event Definition	Maintain 200 MW of operating reserves when shedding firm load; voltage reduction and demand resources are deployed before shedding firm load.	Firm load shed after deploying interruptible and depletion of 30 minute reserves, but before voltage reduction or depletion of 10 minute reserves.	Firm load shed after depletion of 30 and 10 minute reserves, and calling voltage reduction. Emergency Operating Procedures also anticipate some benefit from voluntary curtailment and public appeals.	Firm load after all operating reserves are depleted and system is just able to sustain frequency with no regulation. No mention of voltage control. DR is removed from load before simulation and is therefore treated as deployed.	Not explicitly defined.	Before firm load shed, all voltage reduction options are exhausted. Firm load will be shed to maintain the full operating reserve requirement including spinning and non-spinning reserves.
Reserve Margin Accounting	Reliability requirement reported both including and excluding portion of tie benefits; intermittent resource values derated.	Nameplate capacity for thermal resources; derate wind and solar according to expected reliability benefit. Does not include voltage reduction.	Nameplate capacity for all resources; does not include voltage reduction.	Nameplate capacity for thermal resources but derate wind.	Nameplate capacity for thermal resources; derate wind and solar according to expected reliability benefit. Does not include voltage reduction.	Voltage reduction treated as a supply resource. Derate interruptible and intermittent resources according to their expected reliability benefit.
Neighbor Assistance	Uses a tie benefit of 1,676 MW that is modeled as a resource; different treatment of firm and non-firm imports.	Model external areas with diversity of weather and unit performance, up to a maximum assumed non-firm import capability of 3,500 MW.	Model external areas with same load shape during peak events.	Model 7 external regions at their planning reserve margin levels. Neighbors provide assistance until all operating reserves are depleted. Assumes 9,000 MW of import capability.	Assume 0 MW from outside areas.	Model neighbors' load and resource diversity.
Model	GE-MARS	GE-MARS and PRISM	GE-MARS	GE-MARS	ABB Grid View	SERVM

Sources:
ISO-NE (2012); PJM (2011); NYSRC (2011); MISO (2012c); SPP (2010); and Georgia Power (2010).

B. DETAIL ON SIMULATION MODELING AND ASSUMPTIONS

The most important modeling assumptions implemented in our study as well as a general description of how these assumptions are implemented within SERVM are documented in Section II within the body of this report. We supplement that more general discussion within this Appendix by providing additional supporting detail on our assumptions regarding: (1) intertie availability; (2) forced and maintenance outage modeling for thermal resources; (3) hydro resource modeling; (4) intermittent resource modeling; and (5) weather uncertainty and load modeling.

1. Interregional Tie Line Availability

As explained in Sections II.A-B, SERVM uses a transmission-constrained economic dispatch to schedule power flows among regions. We simulate the availability of each intertie over a probability distribution between 60% and 100% of the path rating. For simplicity, we assume that the interties are simultaneously feasible and that the availability of any one intertie is independent of the others' availability. Figure 45 shows the non-simultaneous import capability of each path, while Figure 46 shows the simultaneous import capability of the Study RTO from all directions. The maximum simultaneous import capability to the Study RTO Region is 11,000 MW, although it is less than 8,000 MW in 50% of all hours.

Figure 45
Non-Simultaneous Tie-Line Availability Distributions

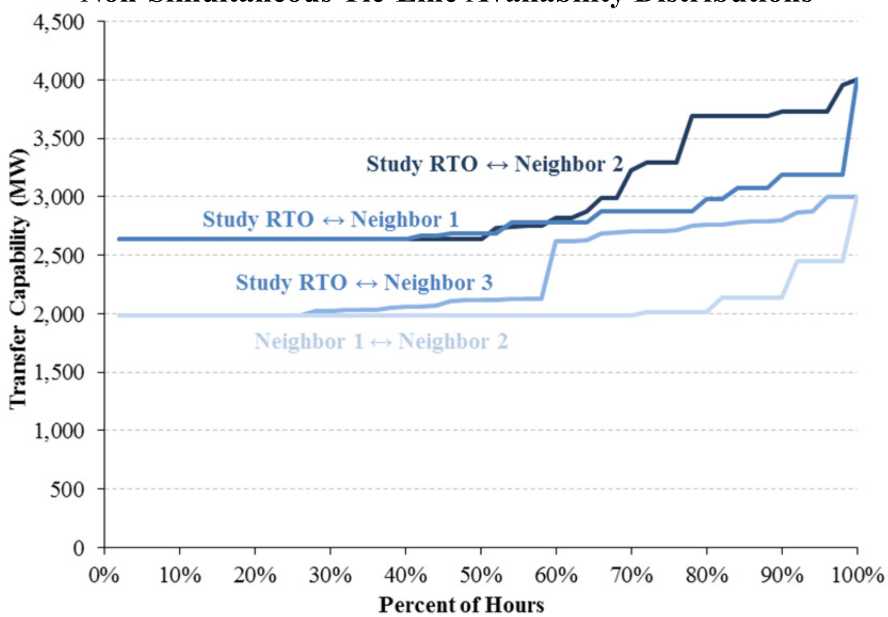
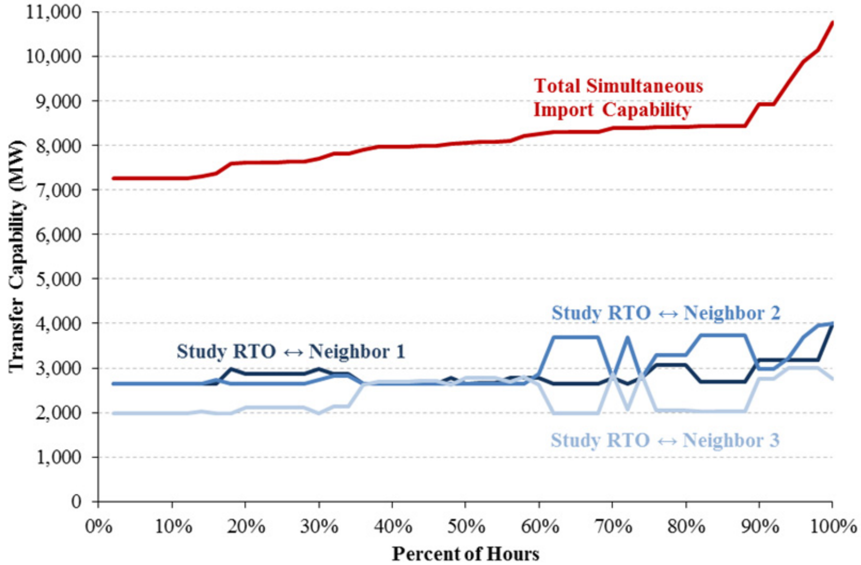


Figure 46
Simultaneous Study RTO Import Capability



2. Thermal Resource Forced and Maintenance Outage Assumptions

We provide here additional detail regarding how SERVM captures the probability of forced and maintenance outages for thermal resources. Average resource availability is consistent with NERC Effective Forced Outage Rate (EFORd) data from 2006–2010 by unit type and size.[166] Unlike most production cost and reliability models, SERVM does not use an average outage rate for each unit to approximately capture unit availability. Instead, SERVM simulates unit outages using random event draws from representative probability distributions. We developed these distributions based on previous modeling work, and scaled these distributions to match the national average outage rates. We also vary the outage rates seasonally to capture different operating profiles in summer, shoulder, and winter months.

[166] From NERC (2011b).

Specifically, outage events are characterized by the probability distributions around the following variables for full, partial, and maintenance outages, with the fleet-average values of key parameters as summarized in Table 16:

Full Outages are characterized by distributions of: (1) Time-to-Repair Hours; and (2) Time-to-Fail Hours.

Partial Outages are characterized by distributions of: (1) Partial Outage Time-to-Repair Hours; (2) Partial Outage Derate Percentage; and (3) Partial Outage Time-to-Fail Hours.

Maintenance Outages are identified based on the percentage of full outages that have some scheduling flexibility. These outages are scheduled in off-peak periods to the extent feasible.

To further illustrate the outage modeling approach in SERVM, consider a unit with assumed distributions for Time-to-Repair after an event, Time-to-Fail between events, and the other variables listed above. If the unit is online in hour 1, SERVM will randomly draw Time-to-Fail values from the distributions for both full outages and partial outages. The unit will run for that amount of time before failing. A partial outage will be triggered first if the selected Time-to-Fail value is less than the selected full outage Time-to-Fail value. Next, the SERVM will draw a Time-to-Repair value from the distribution and be on forced outage for that number of hours. When the repair is complete, it will draw new partial-outage and full-outage Time-to-Fail values. The process repeats until the end of the simulated year, when it will begin again for the subsequent iteration. This detailed multi-state stochastic modeling captures the tails of the distribution over potential low-probability, high-impact reliability outcomes that a simple convolution method would not capture.

Table 16
Fleet-Average Outage Characteristics by Unit Type

Unit Type	**Forced Outage Rate** *(%)*	**Mean Time to Repair** *(hours)*	**Mean Time to Fail** *(hours)*
Nuclear	3.0%	146	6,454
Coal	6.8%	95	2,087
Biomass/LFG	8.4%	120	2,295
Gas Combined Cycle	5.0%	68	2,018
Gas Steam Turbines	7.0%	104	2,223
Steam Oil	6.2%	108	2,691
Gas Combustion Turbines	7.8%	47	551
Oil Combustion Turbines	11.8%	60	451
Overall Fleet	**6.3%**	**92**	**2,443**

Sources and Notes:
Represents fleet average values, weighted by units' nameplate capacity.
Mean time to repair and mean time to fail values exclude partial outages.
Forced outage data from the Generation Availability Data System (GADS), NERC (2011b).

3. Hydro Modeling

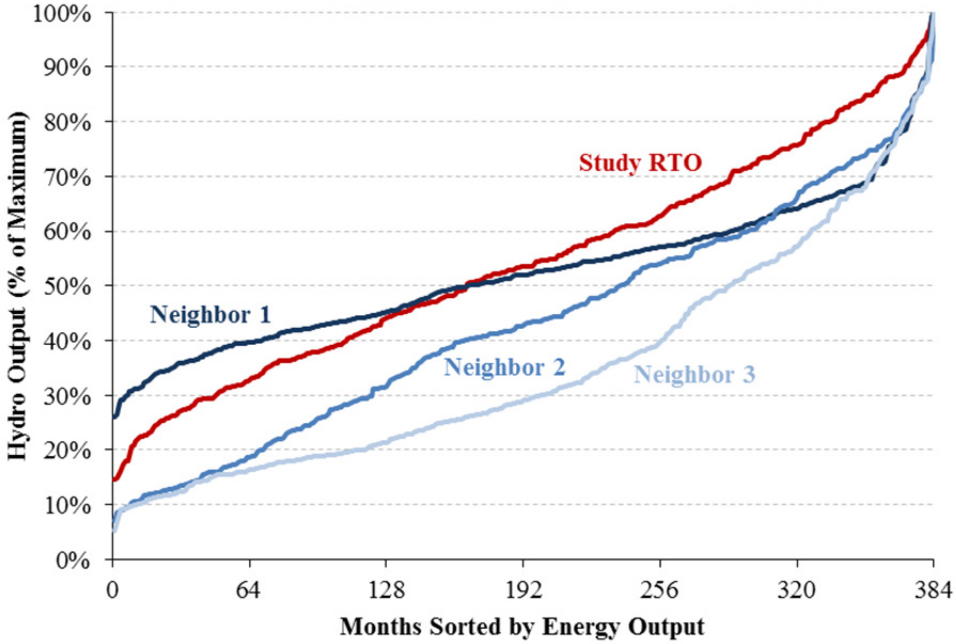
We model the hydro portfolio in each region based on segments treated as non-schedulable run of river, schedulable peak shaving hydro, and dispatchable emergency capacity. The run-of-river segment is dispatched as baseload capacity providing its designated capacity every hour of the year. The schedulable hydro is used for shaving the daily peak load, subject to minimum daily flow requirements. The emergency capacity is used only to prevent firm load shed, meaning that SERVM allows the emergency mode to "borrow" up to a few hours' worth of energy from future dispatch of the scheduled hydro output. Typically, hydro resources cannot dispatch at their nameplate capacity during peak hours due to water supply limitations or river flow requirements. By modeling hydro resources in these three segments, SERVM captures the likelihood that incremental hydro resources will be available during peak and emergency conditions.

Using FERC data on historical monthly hydro generation, we prepared resource availability profiles for the same regions and historical weather years used in our load modeling.[167] In years with little historical hydro generation, SERVM models correspondingly little generation and capacity available during peak conditions. In years with substantial historical generation, SERVM models a substantial portion of the hydro fleet in run-of-river status with additional dispatch flexibility during peak conditions. Extreme shortage events in which high load and low hydro conditions coincide are modeled in SERVM only to the extent that such conditions have been observed over the historical weather and hydro years that we examine.

Figure 47 shows the distribution of monthly hydro generation for each modeled region across the range of weather scenarios modeled. The figure also shows that not all modeled regions have the same level of reliability in their hydro resource, with Neighbor 1 having the most consistent hydro resource and Neighbor 3 realizing the most frequent low-hydro conditions.

[167] Data from EIA (2013).

Figure 47
Hydro Energy Variation by Month and Region



Sources and Notes:
Data adapted from actual systems' monthly hydro data as reported in EIA (2013).

4. Intermittent Resource Modeling

As explained in Section II.C.3 above, wind and solar resources are modeled as non-dispatchable intermittent resources. For wind resources, we use hourly EWITS data from years 2004–2006.[168] We aggregate these data by state, consistent with the weather stations we used in our load modeling to develop three years' worth of hourly wind profiles. SERVM randomly draws a date from within the month being simulated, and uses the daily wind profile from each region consistent with that date in order to maintain the appropriate inter-regional correlations in wind output. For example, if SERVM is currently simulating the month of July, it may randomly select the date July 5, 2006 as the basis for the wind profiles from all four regions.

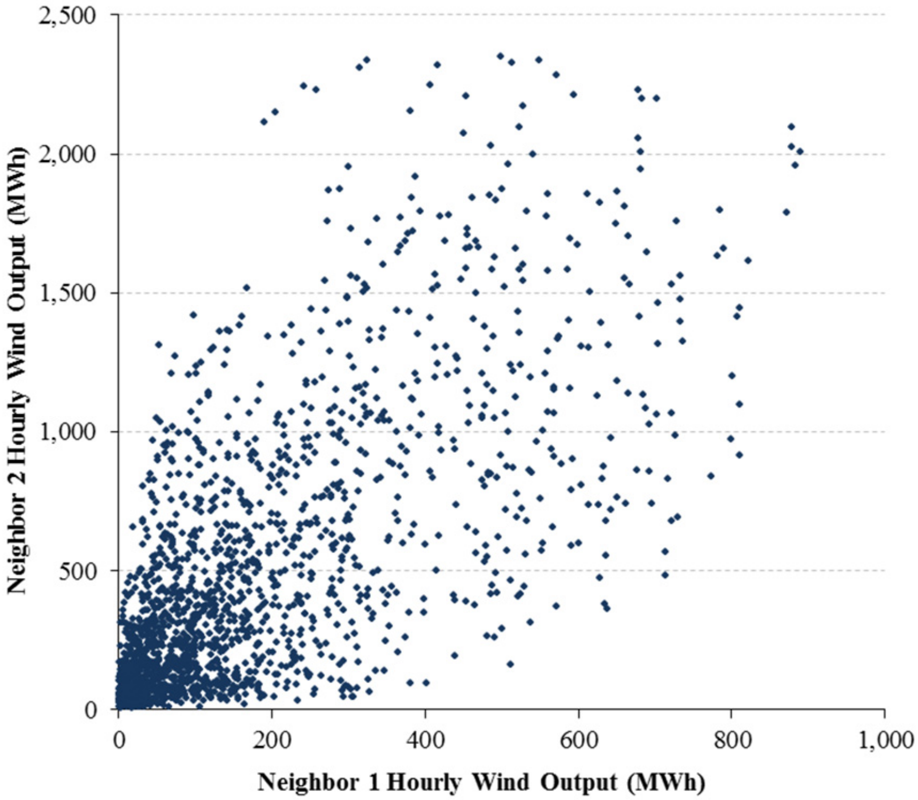
As demonstrated in Figure 48 for Regions 1 and 2 (based on EWITS wind profiles for central MISO and western PJM), there is some correlation in hourly wind output among neighboring regions, but this correlation is small compared to the total volatility in wind output. Consistent with the geography of weather and hydro conditions, we used aggregate EWITS wind profiles for Tennessee (with an annual capacity factor 31%) for the Study RTO.

We assume that solar capacity has a low penetration level in all regions that we model and so this resource has minimal impact on study results. We use PV Watts data to develop a typical hourly

[168] See NREL (2013a).

annual profile for each region.[169] Similar to wind, SERVM randomly draws a daily profile by month for the aggregated solar generation in each region.

Figure 48
Correlation in Hourly Wind Output in Neighbors 1 and 2 During Summer Peak Hours



Sources and Notes:
Data adapted from EWITS data for central MISO and western PJM, see NREL (2013a).

5. Treatment of Weather Uncertainty in Load Modeling

This section provides additional detail on how weather uncertainty is modeled, as summarized in Section II.D.1 above. Table 17 lists the weather stations used to represent the Study RTO and three neighboring systems.

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[169] From NREL (2013b).

Table 17
Weather Stations Used to Represent Each Modeled System

Modeled System	Weather Stations
Study RTO	Chattanooga, TN Nashville, TN Knoxville, TN Huntsville, AL
Neighbor 1	Indianapolis, IN St. Louis, MO Springfield, IL
Neighbor 2	Columbus, OH Baltimore, MD Charleston, WV Richmond, VA
Neighbor 3	Atlanta, GA Birmingham, AL Mobile, AL Montgomery, AL Macon, GA

As explained in Section II.D.1, we estimate econometric relationships between recent historical loads and weather to develop 32 synthetic annul load profiles that are consistent with 32 years of historical weather data. The following three figures show the range of load profiles we model, with summer peak load in Figure 49, winter peak load in Figure 50, and total annual energy in Figure 51. In each case, the figures show the percentage by which the 99th percentile, 95th percentile, and 90th percentile extreme loads exceed the weather-normalized load.

As shown in Figure 28, extreme weather can cause peak load to substantially exceed the expected normal (*i.e.*, 50/50 peak load) condition. In fact, each region can expect actual peak load to exceed weather-normal peak load by more than 5% once every ten years solely due to weather conditions, with extremes of up to 9% in rarer cases. As shown in Figure 50, winter peak variance is highest for the Study RTO Region and Outside Region 3, although the duration of these peaks is shorter and the average winter peak is lower than the average summer peak. This means that most reliability events are still most likely to occur during the summer. Outside Regions 1 and 2 are only summer-peaking, and so cold weather events do not impact these regions substantially. Finally, as shown in Figure 51, annual energy does not vary as substantially as summer and winter peak loads because it takes into account all hours of the year, and many off-peak hours have more stable load profiles that are not as heavily influenced by weather.

Figure 49
Summer Peak Load in Extreme Years as Percent above Weather-Normal Peak

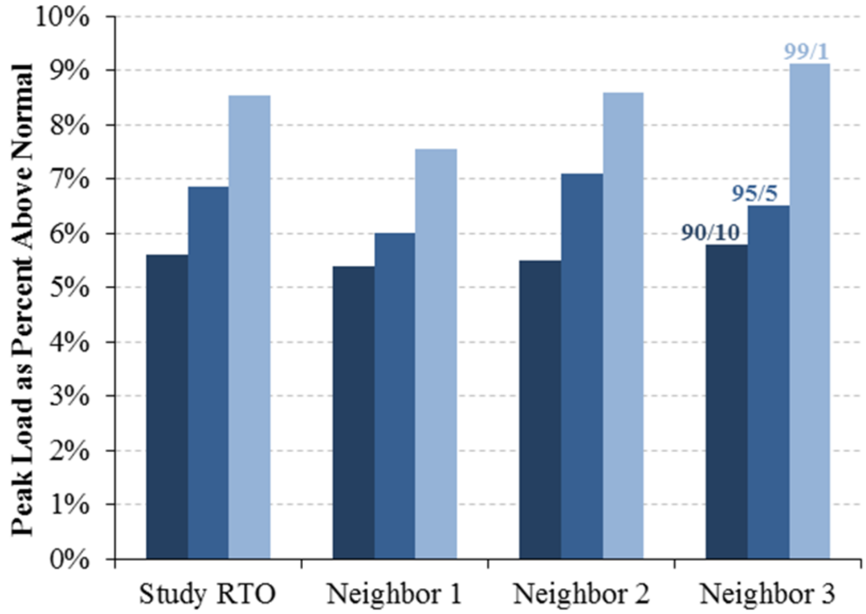


Figure 50
Winter Peak Load in Extreme Years as Percent above Weather-Normal Peak

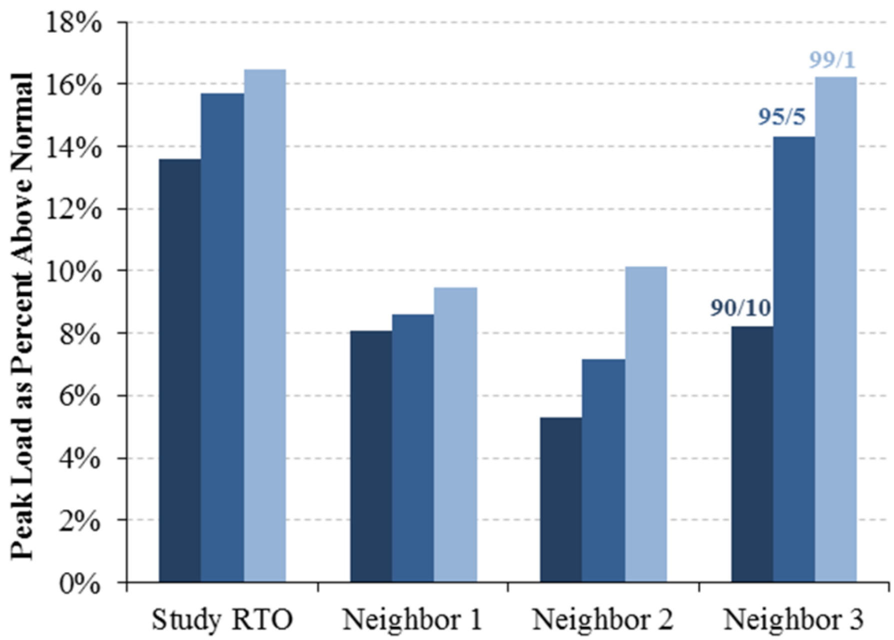
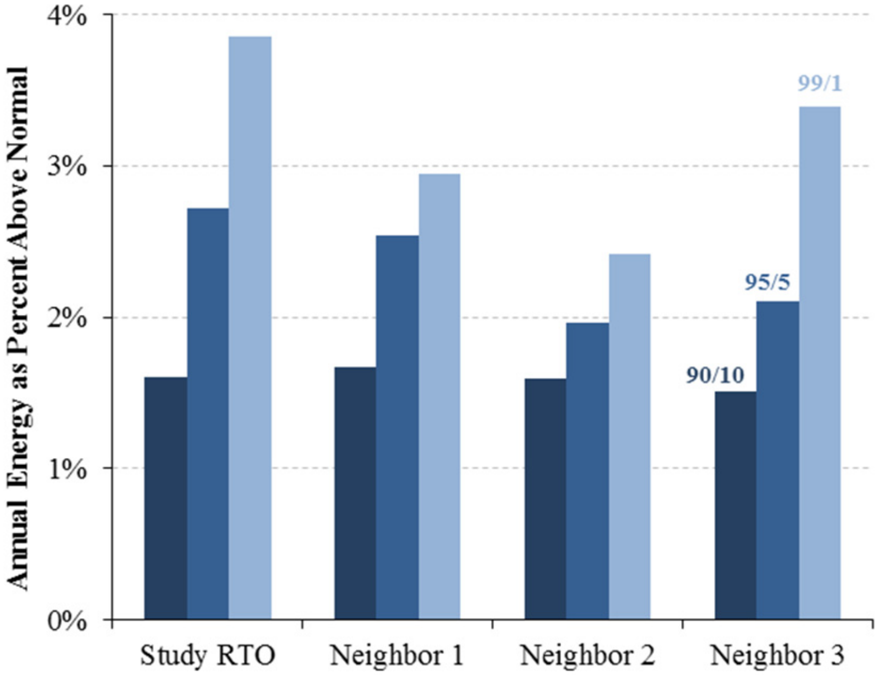
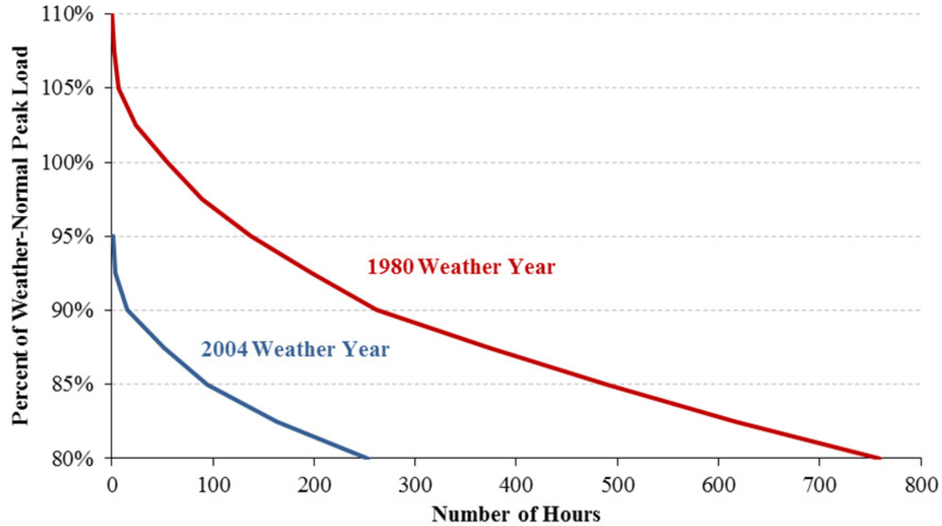


Figure 51
Annual Energy in Extreme Years as Percent above Weather-Normal Year



Reliability outcomes are also heavily influenced by the duration of severe temperatures, particularly because some summers may have extremely high temperatures for only a few days while other years' experience sustained high-cost events with high temperatures for the duration of the entire summer. For example, Figure 52 shows the load duration curve for the Study RTO Region relative to weather-normalized peak load for two years, one that has high relatively high system peak load and one relatively low peak load. Note that 2004 weather year produced a peak load of only 95% of the weather-normal peak load, while the 1980 weather year experienced a peak of 10% above normal, as well as a much larger number of high-load hours, driven by a sustained summer heat wave.

Figure 52
Duration of Extreme Hours



Finally, each region can expect some level of neighbor assistance during peaking conditions, since the systems will peak at slightly different times. Table 18 summarizes shows the load diversity between the Study RTO and the three neighbors in the weather-normal year, comparing non-coincident peak load to peak load during: (a) the multi-regional coincident peak; and (b) the Study RTO peak. Note that diversity between the Study RTO and Neighbor 3 is relatively low while the Study RTO has more diversity with Neighbors 1 and 2. This is important in our reliability simulations in that most neighbor assistance during the Study RTO's system peak will be available from these two regions. On a total system basis, the weather diversity reduces the individual regions' non-coincident peak load of 180,000 MW by 3% to a combined multi-region coincident peak of 174,668 MW.

Table 18
Load Diversity for Study RTO and its Neighbors
(During Multi-System Coincident Peak and Study RTO Peak)

	Peak Load			Load Diversity	
	Non-Coincident Peak *(MW)*	During Multi-Region Coincident Peak *(MW)*	During Study RTO Peak *(MW)*	Relative to Multi-Region Coincident Peak *(%)*	Relative to Study RTO Peak *(%)*
Study RTO	50,000	48,605	50,000	2.8%	0.0%
Neighbor 1	60,000	58,686	54,399	2.2%	9.3%
Neighbor 2	40,000	38,604	35,242	3.5%	11.8%
Neighbor 3	30,000	28,773	28,887	4.1%	3.7%
Total	**180,000**	**174,668**	**168,528**	**3.0%**	**6.4%**