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EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

The Economic Ramifications of Resource Adequacy White Paper

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Astrape Consulting
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About the Authors:

Kevin Carden is Director and Nick Wintermantel is a Principal of Astrape Consulting, an energy consulting firm with a focus on resource adequacy and the probabilistic simulations of power systems. Kevin and Nick have performed resource adequacy studies in various jurisdictions across the U.S. using their Strategic Energy and Risk Valuation Model (SERVM). They can be contacted at www.astrape.com.

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Disclaimers:

EXECUTIVE SUMMARY

Resource adequacy is of critical importance to utilities, consumers, and regulators. The financial impact of shedding firm load or having scarcity events in the electric energy market can be measured in billions of dollars as evidenced by the California Energy Crisis in the early 2000's and more recently during the extreme weather in Texas in the summer of 2011. These events illustrate that the value provided by electric service far exceeds the physical costs of producing the electricity. Surveys of electric service outage costs indicate that the Value of Lost Load (VOLL) can be $15,000/MWh[1] or greater while the production cost of a marginal unit can be only $50/MWh – a factor of 300x. This comparison, however, ignores a critical component of the economics of resource adequacy – the carrying costs of having excess capacity available during those peak hours. Assuming the carrying cost of new capacity is $100,000/MW-yr and VOLL is $15,000/MWh, the capacity must be used to prevent firm load shed more than 6 hours per year to be economically justified. However, in most regions, marginal capacity is needed to prevent firm load shed much less frequently. The resource adequacy standard many regions plan to is a Loss of Load Expectation (LOLE) of one firm load shed event in 10 years (herein referred to as 1-in-10 LOLE), suggesting the last resource added to the system is only needed approximately 0.3 hours per year[2]. At this frequency of utilization, VOLL would have to be an unrealistic $300,000/MWh to justify the last resource addition. For a point of reference, $300,000/MWh VOLL is comparable to $900 for keeping the power on in a normal sized house for one hour[3]. This review suggests that if marginal capacity's only benefit was avoiding firm load shed events, it is unlikely economics would justify maintaining a system as reliable as we have today. The example above illustrated the economics for only shedding firm load due to generation deficiency once every 10 years. However, actual resource adequacy is typically even higher than that. While distribution related outages occur several hours per year for most customers[4], most regions in the Eastern Interconnection have not experienced generation deficiency caused firm load shed events in decades.

But is resource adequacy solely about having enough capacity to meet firm load obligations? Or are there other benefits of reserves that should be considered when setting target Reserve Margins[5]? When load is high and supplies are scarce, market prices can far exceed the production cost of an efficient Combustion Turbine (CT). How much of these costs should be avoided by building additional capacity? There are also other substantive benefits of having robust levels of reserves such as avoiding the dispatch of high cost units or energy limited resources. Economic resource adequacy assessments should take a

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[1] Estimates of VOLL vary widely. The range of estimates and their impact on resource adequacy planning are discussed in Section IV.

[2] A typical firm load shed event has a 3 hour duration. One event in 10 years equals 3 hours in 10 years or 0.3 hours per year.

[3] An average house uses 3kW on peak. Three kWh divided by 1000 kW/MW times $300,000/MWh = $900.

[4] Newell, Sam, "ERCOT Investment Incentives and Resource Adequacy", Retrieved August 25, 2012 from http://www.ercot.com/content/news/presentations/2012/The%20Brattle%20Group%20Presentation%20for%20PUCT%20July%2027%202012%20Work.pdf

[5] In this paper, Reserve Margin is calculated by: (Total Capacity Resources – Expected Annual Peak Load) / Expected Annual Peak Load. Conventional resources and demand side programs are counted at full nameplate or designated capacity. Demand side resources are accounted for in projecting the Expected Annual Peak Load. Only a portion of intermittent resource nameplate capacity is counted as a capacity resource.

comprehensive approach to calculating the trade-off between the cost of additional capacity and the economic benefit provided by those resources. This white paper attempts to quantify this trade-off for a defined base case and a number of sensitivities. The point at which the cost of further resource additions is equal to the economic benefit provided by such additions is herein referred to as the economic reserve margin or economically optimal reserve margin or risk neutral economic reserve margin.

For the case study included in this paper, the economic optimal reserve margin is based on minimizing total systems costs from the perspective of the customers of a vertically integrated utility. These costs include all production costs of the utility plus net imports from outside regions plus the societal costs of firm load shed events. In this setup, during reliability events, only incremental purchases are assigned high costs since all load served by the utility's resources is priced at its respective production cost. In these hours, customers continue to receive the benefit of low cost, base load units such as coal and nuclear. The total customer costs then are a combination of low cost energy from existing resources plus incremental energy purchases from the market at higher costs during capacity shortfalls. Also, in this type of environment, a utility pays for incremental capacity costs which are included as part of total system costs. However, in structured markets, the cost of energy is the same for all load since energy is priced based on the marginal resource. If the market price of energy is $800/MWh, then all load must pay this price. However, the mechanism under which energy costs are ultimately passed on to customers can be quite different from region to region depending on market structure and whether or not a load serving entity self supplies a large portion of its load. Also, capacity costs are frequently handled differently. The question of economic reliability is fundamentally different in these markets and is addressed separately in this paper.

The following key conclusions were made based on the resource adequacy assessment research and simulated case study:

- Reviews of various resource adequacy assessments in the Eastern Interconnection indicate wide variations in the way capacity is counted, what level of benefit will be received from emergency operating procedures, and what assumptions and tools are used. Even though many regions use 1-in-10 LOLE or a similar metric, these variations make the comparison of reliability difficult.
- Most prior studies that evaluated the economics of resource adequacy indicated low optimal economic reserve margins. The authors believe this is primarily because only a subset of all customer benefits of the marginal capacity was captured.
- When considering all benefits (production cost savings, import cost savings during shortages, and the societal cost of Expected Unserved Energy (EUE)) of marginal capacity from the perspective of a customer of a single vertically integrated utility, the economic reserve margin is greater than that indicated by 1-in-10 LOLE for many regions. However, system size, resource mix, load shape, market availability and other factors can affect the optimum economic reserve margin and make it either higher or lower than the 1-in-10 LOLE based reserve margin.
- If economic targets were based solely on societal costs (production costs plus the cost of EUE) and ignored scarcity pricing that result in transfers of wealth to outside regions or generators, the economic target would decrease by several percentage points. However, the authors do not believe this setup is realistic or desirable.
- Risk analysis shows that a range of reserve margins slightly above the economic optimal reserve margin can avoid a number of potentially high cost scenarios for little additional cost.

- Modeling assumptions for neighboring regions such as weather diversity and import capability have a significant impact on both the 1-in-10 LOLE and economic optimal reserve margin
- Because unserved energy is de minimus at a 1-in-10 LOLE based reserve margin, the Value of Lost Load has little impact on the economic analysis. Instead it is driven by the dispatch of high cost resources and scarcity pricing events which occur much more frequently than loss of load events.
- Not all capacity resources provide the same value. Most resource planners recognize that wind and solar may provide little load carrying capability relative to their nameplate capacity. However, in addition to those resources, demand response, energy storage, and hydro also have very different load carrying capability as well as economic capacity value, and their respective value should be taken into account.
- Resource adequacy targets should evolve to properly balance the costs and benefits of reliability if the 1-in-10 LOLE based reserve margin level is not justified.
- Merchant generators in energy only markets will likely not recover their fixed costs at a 1-in-10 LOLE based reserve margin or an economic optimal reserve margin based on the perspective of customers in a regulated utility environment.
- Because all generators are paid the same price under current forward capacity market constructs, the total costs to consumers to maintain a 1-in-10 based reserve margin that is above the energy only market economic target will always be higher, however, there is some risk benefit seen by customers due to the reduction of high cost outcomes.

Future Analysis

While this white paper provides a number of informative conclusions to assist regulators in reviewing the reasonableness of resource adequacy plans, many questions remain outstanding that were beyond the scope of the original effort. This paper was not designed to identify the most appropriate economic reserve margins for particular regions, utilities, ISOs and RTOs, but the case studies indicate they could be different from current targets by 5% or more. If current reserve margin targets are 5% too high or 5% too low, the economic inefficiency for individual regions could be in the hundreds of millions of dollars per year. Further, case studies indicated that changing penetrations of demand response and intermittent resources can affect resource adequacy planning, but the way that the impact of these resources should be addressed is highly specific to individual markets. Also, how should economic resource adequacy be addressed by states in structured markets?

The results of this white paper should not be construed to suggest that resource adequacy planning is already approximately optimal in the Eastern Interconnection. There are significant opportunities for resource adequacy planning to produce substantial economic benefits for consumers. Additional analysis could provide key insights into how this could be accomplished.

- Potential Tasks:
  - Assess the economic efficiency of the reliability standards of particular regions, utilities, ISOs and RTOs in the Eastern Interconnect. To perform this assessment, the following steps would need to be performed:
    - Build load, resource, and transmission data for the remainder of the regions in the Eastern Interconnection
    - Refine unit availability data and transmission availability data for the regions already modeled.

        - Perform simulations for the entire Eastern Interconnection and determine one economic optimal reserve margin assuming coordinated planning across the entire Interconnect.
        - Provide comparisons of economically derived reserve margins to current resource adequacy plans.
        - Provide additional sensitivities around key assumptions such as scarcity pricing, economic load forecast uncertainty, and demand response constraints.
        - Analyze different market structures and rules to understand the impact. Use economic reliability simulations to estimate demand curves for capacity markets.
    - Demand response programs play a significant and expanding role in addressing resource adequacy. As the penetration of demand response increases, the flexibility and availability required of these resources will also rise. The treatment of these programs in various market structures must also be considered as their value profile can be very different from traditional resources and can change vastly from program to program. Several sensitivities were performed to quantify some of these considerations, but additional work is warranted. The additional work would primarily examine different types of demand response programs with different characteristics. These include reliability only, economic, and real time pricing programs. Optimal demand response portfolios could also be developed.
    - Resource adequacy is not just a concern during the peak hours of the year. Changing resource mixes will require different types of assessments to address flexibility requirements for many hours of the year due to wind and other intermittent resources. While the cost of intermittent resource integration has been addressed in a number of studies, the impact of intermittent resources on operational resource adequacy has not received as much focus. An additional assessment that captures the flexibility of existing resources, the variability of loads, and the variability of intermittent resources on time intervals from minutes to days could be performed with the Strategic Energy and Risk Valuation Model (SERVM) used for this white paper. In addition to providing an assessment of potential challenges including the frequency, magnitude, and financial impact of reliability problems due to intermittency, several alternative solutions could be modeled to identify the most reliable and cost effective approaches to mitigating these events.
    - The work performed in this study could be leveraged to assess the reliability impact of certain transmission components probabilistically. Pairing SERVM with a transmission model such as EPRI's TransCARE would allow for the assessment of combined generation and transmission reliability. SERVM would be used to develop scenarios of load, weather, and unit commitment and feed subsets of those scenarios to the transmission module to understand the impact of probabilistic operation and failure of specific transmission components.

I. HISTORY OF RESOURCE ADEQUACY AND HOW TARGETS SHOULD EVOLVE

Resource Adequacy is a measure of an electric system's ability to provide adequate generation to meet all firm load obligations. If firm load obligations exceed the instantaneous generating capacity of a system, some firm load customers will have their access to electricity cut. This is a firm load shed event. Outages of firm load due to non-generation equipment failures and storms are not considered resource adequacy issues. Typical metrics of resource adequacy include Loss of Load Hours (LOLH), Loss of Load Probability (LOLP), Loss of Load Events (LOLE), and Expected Unserved Energy (EUE). LOLH is a count of the number of hours in a year expected to have firm load shed. LOLP is the ratio of hours or days expected to have any firm load shed to the total hours or days in a year and is expressed as a percentage. LOLE is typically measured as a count of the expected number of days with at least one hour of lost load. EUE is the sum of all the expected firm load energy shed measured in MWh. It is the only one of these metrics that considers the magnitude of the outage. (Section II expands on these definitions, interpretations, and implementations of traditional reliability metrics)

Most electrical systems in North America have a resource adequacy target based on a defined physical reliability metric. While informal reliability targets have likely been utilized since electricity was first commercialized, the first mention of probabilistic resource adequacy assessments using specific physical reliability metrics identified in our research was in technical papers from the 30's and 40's. Giuseppe Calabrese' 1947 paper 'Generating Reserve Capacity Determined by the Probability Method' references setting reliability targets based on an expected number of days of loss of load over a given number of years[6]. C.W. Watchorn wrote several papers which discuss the development of appropriate system capacity reserves. In one such paper, Watchorn states "It is believed that a reasonable level of service reliability...is a probability of failure to carry the load of in the order of an average rate of one day in from eight to ten years".[7] However, the basis for that belief was not provided. Similar references to service reliability levels of 1 outage in every 10 years are made in dozens of technical papers from the 50's onward, although it is not clear from our review whether utilities or regions formalized resource adequacy targets around specific reliability metrics until several decades later. (See R. Billinton's bibliography of the history of resource adequacy assessments[8] for further references)

On November 9, 1965, a major electric power disruption in the Northeast US and Eastern Canada left 30 million people without power for over 12 hours. Although the cause of this event was primarily due to operator error, the event did occur during high load conditions.[9] In an effort to prevent the occurrence of similar events, electric utilities formed the North American Electric Reliability Council (NERC) in 1968. NERC reliability standards are focused on operating practices to ensure security ("the ability of the electric system to

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[6] Calabrese, Giuseppe, "Generating Reserve Capacity Determined by the Probability Method," American Institute of Electrical Engineers, Transactions of the IEEE, vol.66, no.1, pp.1439-1450, Jan. 1947

[7] Watchorn, C. W., "The Determination and Allocation of the Capacity Benefits Resulting from Interconnecting Two or More Generating Systems," American Institute of Electrical Engineers, Transactions of the IEEE , vol.69, no.2, pp.1180-1186, Jan. 1950

[8] Billinton, Roy, "Bibliography on the Application of Probability Methods in Power System Reliability Evaluation" IEEE Transmission Power Apparatus System, vol.91, no.2, pp.649-660, Mar/Apr 1972

[9] *Northeast Blackout of 1965.* Retrieved August 25, 2012, from http://en.wikipedia.org/wiki/Northeast_blackout_of_1965

withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements."[10]). However, the renewed focus on overall reliability also led to the development of specific resource adequacy targets. Mid Atlantic Area Council (MAAC) Reliability Principles and Standards set in place in 1968 state: "Sufficient megawatt generating capacity shall be installed to ensure that in each year for the MAAC system the probability of occurrence of load exceeding the available generating capacity shall not be greater, on the average, than one day in ten years."[11] Many other utilities and regions adopted similar standards.

How Should Resource Adequacy Targets Evolve?

One of the interesting aspects of reliability planning is that Resource Adequacy related outages represent a very small percentage of overall outages. As an example, the Brattle Group estimated that customers in Texas would average less than 1 minute per year of outages due to insufficient generation if the system was planned to maintain a 15% reserve margin.[12] This compares to an actual average of 100 - 300 minutes of outages per customer when all types of outages, including transmission and distribution outages, are considered.[13] Statistics are similar nationwide. A survey of utilities shows 107 minutes of outages per customer when all types of outages are considered.[14] Since resource adequacy events comprise only 1% or less of overall outages, why do they receive a high level of focus? Would a 1 in 5 or 1 in 2 LOLE be a reasonable level of physical reliability?

While 1-in-10 LOLE appears to be difficult to support from solely a physical reliability standpoint, several regions note other benefits of high levels of reliability. PJM states that "a well planned and adequate power system will lead to a secure system in day to day operations."[15] The California ISO suggests that high physical reliability supports the proper functioning of markets and that "market economics and reliability are inextricably intertwined." [16] There is little doubt that increased resource adequacy also plays a role in reducing high hourly market price scenarios. Many utilities mention additional unknowns beyond the factors considered in developing the 1-in-10 LOLE target such as fuel availability risk and environmental legislative risk that could force retirements of existing units. These points suggest there may be some margin of error embedded in the 1-in-10 LOLE target for some regions or utilities. In other words, unknown risks may push a system that is planned to

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[10] Glossary of Terms, prepared by the Glossary of terms Task force(GOTTF) North American Electric Reliability Council, GOTTF formed jointly by the NERC Engineering Committee(EC) and Operating Committee(OC), August 1996, www.nerc.com/glossary/glossary-body.html

[11] MAAC Reliability Principles and Standards, As adopted on July 18, 1968 by the Executive Board constituted under the MAAC Agreement, dated December 26, 1967 and revised March 30, 1990, Document A-1.

[12] Newell, Sam, "ERCOT Investment Incentives and Resource Adequacy", Retrieved August 25, 2012 from http://www.ercot.com/content/news/presentations/2012/The%20Brattle%20Group%20Presentation%20for%20PUCT%20July%2027%202012%20Work.pdf

[13] Ibid.

[14] LaCommare, Kristina, "Understanding the Cost of Power Interruptions to U.S. Electricity Consumers", September 2004, Ernest Orlando Lawrence Berkeley National Laboratory, Retrieved August 25, 2012 from http://certs.lbl.gov/pdf/55718.pdf

[15] PJM Generation Adequacy Analysis, October 2003, PJM Interconnection L.L.C., Retrieved August 25, 2012 from http://www.pjm.com/planning/resource-adequacy-planning/~/media/planning/res-adeq/20040621-white-paper-sections12.ashx

[16] Business Practice Manual for Reliability Requirements, August 9, 2012, California ISO, Retrieved August 25, 2012 from https://bpm.caiso.com/bpm/bpm/doc/000000000001253

a 1-in-10 LOLE target to have reliability that is somewhat lower in actual practice. Beyond the benefits of high levels of reliability afforded by the 1 in 10 standard, resource planners may also have additional motivations for continuing to use the standard. The 1-in-10 LOLE target is simple to calculate and explain and it has substantial precedent.

However, in relation to other cost/benefit analysis performed in the electric power industry, resource adequacy based on the 1-in-10 LOLE standard appears disproportionate. For example, in ERCOT, avoiding a hypothetical addition of 3,250 MW of new combustion turbines (a capital cost savings of more than $1.5B) would only increase customer's average resource adequacy outages from 0.1 minutes per year to 2.8 minutes per year.[17] When compared with 100 - 300 minutes of distribution related outages per customer, the hypothetical combustion turbines do not appear to provide an economically justifiable reliability benefit. Later sections of this white paper quantify some of these other benefits of high reliability mentioned as qualitative motivations supporting the 1-in-10 LOLE standard. Further, with the changing generation resource mixes that include intermittent generation such as wind and solar and a greater penetration of demand response resources, economically optimal reserve margins may vary further from a 1-in-10 LOLE standard than seen in prior studies. Our conclusions in this paper suggest that resource adequacy targets should evolve to properly balance the costs and benefits of reliability if the 1-in-10 LOLE level is not justified.

[17]Newell, Sam, "ERCOT Investment Incentives and Resource Adequacy", July 2012, The Brattle Group, Retrieved August 25, 2012 from http://www.ercot.com/content/news/presentations/2012/The%20Brattle%20Group%20Presentation%20for%20PUCT%20July%2027%202012%20Work.pdf

II. 1 DAY IN 10 YEAR STANDARD

A. TERMINOLOGY

- Loss of Load Expectation (LOLE): Expected number of firm load shed events an electric system expects in a given year
- Loss of Load Probability (LOLP): probability of firm load shed events typically expressed as a % of total hours in a year
- Loss of Load hours (LOLH): Expected number of hours of firm load shed events an system expects in a given year
- 1-in-10 LOLE Standard: Most commonly calculated as 1 event in 10 years and equals 0.1 LOLE per year
- Reserve Margin: (Resources – Peak Firm Demand) / Peak Firm Demand
- Capacity Margin: (Resources – Peak Firm Demand) / Resources

Not all regions and planners use the same definitions for all of these terms. Some refer to LOLP as the probability of having one or more hours of loss of load in any year. Others refer to LOLE as an hourly metric.

B. SURVEY SUMMARY

The results of our survey show that most regions use a similar standard for setting or measuring generation adequacy. Under this standard, adequate reliability is defined as the level of reserves that provide an expectation of less than one event in 10 years due to generation deficiency. While there are a few regions or utilities that use different standards, this standard has been in place for several decades for many of the members of the Eastern Interconnection. Details around the approach used in each area including references are provided in the following sections.

Table 1. Survey Summary

NERC Assessment Area	Reliability Criterion
FRCC	Reserve Margin criteria of 15% as a Regional Reserve Margin (20% for Investor Owned Utilities (IOU) and 15% - 18% for other utilities); Loss of Load Probability (LOLP) criteria of 1 day in 10 years or 0.1 LOLP[18])
SERC	SERC does not have a mandatory reserve margin or resource adequacy requirement for its members; Example Approaches: SOCO/TVA: base target reserve margins on minimizing total customer costs including societal

[18] Based on Astrape's understanding of the FRCC documentation, LOLP of 0.1 is consistent with the traditional 1 event in 10 years since LOLP is being calculated in days per year. FRCC has substituted the term LOLP for LOLE.

	costs of unserved energy; Progress Energy Carolinas: base target on 1-in-10 LOLE and minimizing total customer costs similar to SOCO/TVA.
SPP	Capacity Margin Criterion of 12% for RTO members that are steam based and 9% for hydro based; Capacity margins must meet 1 day in 10 years defined as an LOLE of 2.4 hours per year.[19]
PJM	1-in-10 LOLE (0.1 LOLE)
MISO	1-in-10 LOLE (0.1 LOLE)
NPCC - NY-ISO	1-in-10 LOLE (0.1 LOLE)
NPCC - ISO-NE	1-in-10 LOLE (0.1 LOLE)
NPCC - Maritimes	Reserve Margin criterion of 20% and an 1-in-10 LOLE (0.1 LOLE)
NPCC - Quebec	1-in-10 LOLE (0.1 LOLE)
NPCC - IESO	1-in-10 LOLE (0.1 LOLE)
Saskatchewan	Standard is based on an undisclosed level of Expected Unserved Energy (MWh)
Manitoba	Both an energy criterion and a reserve margin criterion due to the fact that the region is predominantly hydro. The energy criterion requires adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident river flow conditions are repeated. The reserve margin is at least 12%.
MAPP	1-in-10 LOLE (0.1 LOLE); Some of MAPP's members self impose a planning reserve margin of 15% based on the LOLE study performed in 2009.

[19] SPP uses the term LOLE of 2.4 hours which is more traditionally defined as an LOLH of 2.4 hours.

ERCOT	Although ERCOT performs a resource adequacy assessment to determine a target reserve margin necessary to meet 1-in-10 LOLE, there is not a mandatory requirement for the region. ERCOT operates as an energy only market and therefore does not have mandatory capacity requirements.
WECC	In general, each balancing area has responsibility for meeting resource adequacy standards established by respective states in which they operate.

Making the determination of what level of reserves yields 1-in-10 LOLE is a complex task and requires the development of a number of assumptions. There is little consistency in this process from region to region. Recent changes to resource mixes including higher penetrations of wind, solar, and demand response (DR) resources have contributed to even greater disparity between regions. A recent initiative by NERC resulted in a recommended list of modeling assumptions which will help to reconcile some of the disparity[20].

In addition to the disparity of assumptions used in assessing 1-in-10 LOLE, the reporting of the reserve margin that meets 1-in-10 LOLE is not standardized. The primary differences in reserve margin reporting include:

1. The method of capacity accounting. Some regions count all nameplate capacity for all resources. Other regions only count dependable capacity, frequently described as economic load carrying capability (ELCC) of a resource. This is a particular concern for wind, solar, hydro, energy storage, and any other constrained resource. In addition, some regions count expected imports as a capacity resource where others recognize the imports in modeling but do not count those imports as resources in the reserve margin calculation.
2. Emergency operating procedure accounting. Some regions include emergency operating procedures such as voltage control as capacity resources.

The following table attempts to demonstrate the impact of both modeling assumption differences and reserve margin reporting differences for a subset of the regions reviewed in this report to give the reader an appreciation for the different assumptions across regions. Note that some differences are appropriate due to physical differences in either resources or load profiles. The following table does not attempt to differentiate between legitimate and illegitimate assumption differences.

[20] *GTRPMTF Final Report,* Retrieved August 25, 2012, from http://www.nerc.com/docs/pc/gtrpmtf/GTRPMTF_Meth_&_Metrics_Report_final_w._PC_approvals,_revisions_12.08.10.pdf

Table 2: Reserve Margins and Impact on Reserve Margin of Various Assumptions

	PJM	NYISO	NE-ISO	Southern Company	SPP
Reliability Criteria	0.1 LOLE	0.1 LOLE	0.1 LOLE	Economics	2.4 LOLH
Reserve Margin at Reliability Standard	15.30%	16.10%	11.7%	15.00%	10.20%
Study Input Assumptions (Note: these components are not additive.)					
Treatment of Non-Firm Imports (What percentage of capacity resources are from non-contracted external generation)	0.00%	0.00%	2.10%	0.00%	0.00%
Weather Uncertainty (How much higher than normal can load be in extreme cases?)	8.00%	7.30%	10.10%	7.00%	5.30%
Equivalent Forced Outage Rate (Expected percentage of capacity offline during peak conditions)	7.30%	6.80%	4.90%	1.80%	5.90%
Economic Load Growth Uncertainty (How much faster than expected can load grow due to economic conditions?)	1.00%	1.00%	0.00%	2.20%	0.00%
External Assistance Benefit (What percentage of load can be reliably served by external regions)	1.90%	8.60%	5.50%	3.00%	0.00%

ELCC Impact of Wind (Some regions derate their reserve margin to account for variability of wind. For regions that do not, how much would their reported reserve margin drop if they only counted the effective load carrying capability of wind in their reserve margin?)	0.00%	4.70%	0.00%	0.00%	0.00%
ELCC Impact of Demand Response (For regions that discount Demand Response capacity to reflect contract limitations, how much higher would reserve margins be if they counted the full contract capacity?)	0.00%	0.20%	0.00%	1.10%	0.00%
ELCC Impact of Hydro (How much higher would reserve margins be if a region counted full nameplate for all hydro resources?)	0.00%	1.30%	0.00%	0.00%	0.00%
Operating Reserve Procedure Impact (Some regions assume operating reserves would be eliminated before firm load would be shed. Compared to a conservative approach of always maintaining full operating reserves, how much additional capacity do these regions assume?)	1.20%	5.50%	2.10%	0.00%	0.00%
Voltage Reduction Counting (Some regions count voltage reduction as a resource when calculating reserve margin. Other regions do not count voltage reduction as a resource even though they have voltage reduction programs. Compared to the approach of counting voltage reduction as a resource, how does a region's assumption affect their reserve margin?)	2.00%	1.50%	1.50%	0.00%	0.00%

Voltage Reduction Modeling (Some regions do not assume in their modeling that voltage reduction will be used to avoid firm load shed even if it would be called in actual practice. Compared to the standard approach of modeling the expected voltage reduction, how does a region's assumption affect their reserve margin?)	2.00%	0.00%	0.00%	0.00%	0.00%

Table 2 illustrates that a number of reporting and modeling assumptions can have a substantial impact on the reported reserve margin. For instance, in New York, the nameplate capacity of wind is counted in the reserve margin calculation. However, in PJM, the reserve margin calculation only includes the effective capacity of wind. Both regions' studies recognize that wind does not contribute much to reliability, but the accounting difference makes for an unwieldy comparison. If the NYISO accounting treatment was similar to PJM, NYISO's reserve margin would be 11.4% instead of 16.1%. The other items listed in Table 2 further illustrate how difficult it is to compare reserve margins across regions.

Aspects of some regions' modeling approaches seem conservative in some areas or aggressive in other areas. After attempting to normalize for most significant variables, regions may have 1-in-10 LOLE based reserve margins that vary by nearly 10%. Much of this difference is likely due to actual differences in resource mixes, transmission interconnections, and load profiles. However, these factors contribute to making it difficult for Commissioners and other regulators to assess the reasonableness of current resource adequacy planning. Our conclusion is that because of these issues, resource adequacy plans cannot be taken at face value even if all regions plan to a consistent 1-in-10 LOLE standard. If one is interested in comparing resource adequacy from region to region, then it is vital to understand the details surrounding the input assumptions to be able to identify whether a study's results are realistic and can be compared appropriately to studies performed by other entities. The comparisons performed here do not result in an assessment of the reasonableness of any entity's resource adequacy assessment, but rather simply point out the significant differences between studies. As discussed in the future analysis section of this paper, additional work could be performed to assess the reasonableness of each entity's resource adequacy plan.

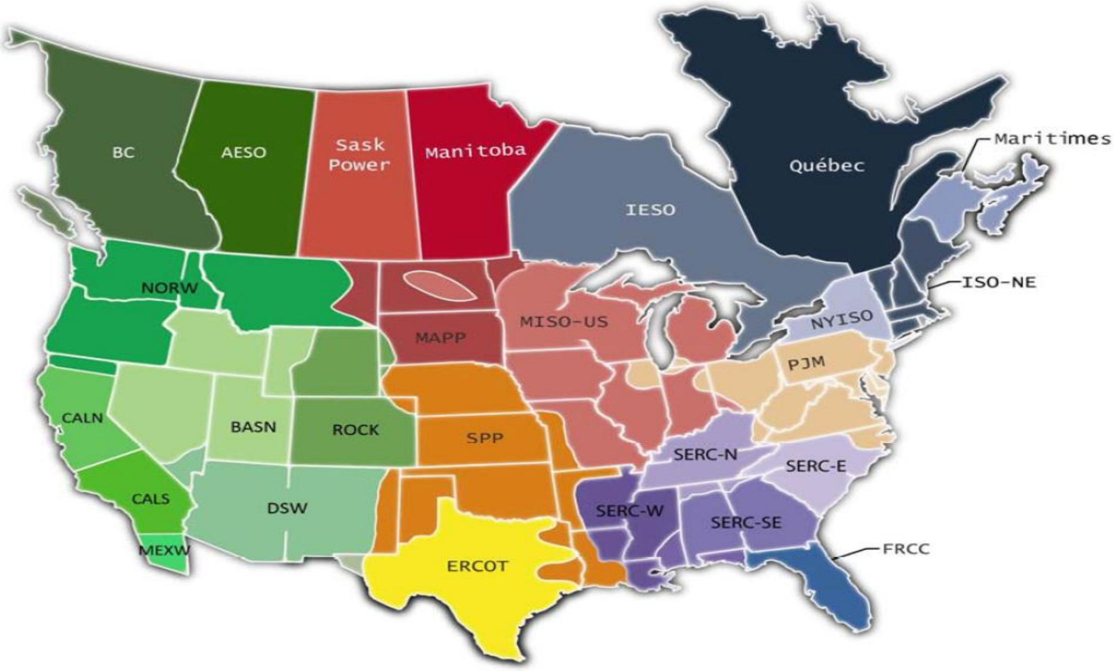
C. Detailed Regional Review

The following sections outline the resource adequacy metric that is used for each NERC Long Term Assessment Area and how it is defined. The sections also contain useful information on how the metric is applied and other key factors impacting resource adequacy decisions.

1. Region Definitions

For this analysis, we will use the NERC Long Term Assessment Areas because resource adequacy criteria and decisions are more often made at this level rather than the other groupings.

Figure 1. NERC Long Term Assessment Areas



2. Eastern Interconnection

- **<u>Florida Reliability Coordinating Council (FRCC)</u>**

  Reliability Criterion: Reserve Margin criteria of 15% as a Regional Reserve Margin (20% for Investor Owned Utilities (IOU) and 15% - 18% for other utilities); Loss of load Probability (LOLP) criteria of 1 day in 10 years or 0.1 LOLP.

  Based on the FRCC 2012 Load & Resource Reliability Assessment Report,

  "The FRCC has a resource criterion of a 15% minimum Regional Reserve based on firm load. FRCC Reserve Margin calculations include merchant plant capacity that is under firm contract to load-serving entities. 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."[21]

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[21] *FRCC 2012 Load and Resource Reliability Assessment*, retrieved on September 1, 2012 from https://www.frcc.com/Reliability/Shared%20Documents/FRCC%20Reliability%20Assessments/FRCC%202012%20Load%20and%20Resource%20Reliability%20Assessment%20Report%20RE%20PC%20Approved%20071012.pdf

The FRCC performed a Loss of Load Probability (LOLP) study in 2009 to verify that the reserve margin criteria were sufficient to meet a maximum LOLP of 0.1 day in a given year. The usage of the term LOLP is different from the traditional definition because it is measured in days per year similar to LOLE. Based on our review, this LOLP of 0.1 in consistent with the traditional 1 event in 10 years. Based on the report, FRCC is also exploring the possibility of a "generation only" reserve margin requirement since demand response penetration is projected to be quite high. Having substantial conventional resources may be important in systems with high penetration of demand response resources due to the voluntary aspect of demand response resources.

FRCC used the TIGER Model to perform its most recent LOLP studies.

- **Southeast Reliability Corporation (SERC)**

  SERC does not have a mandatory reserve margin or resource adequacy requirement for all of its members. Instead, resource adequacy targets are set by individual load serving members and may be subject to review by state regulators of individual members. With this approach, the final target reserve margins vary across the region. For this analysis, we focused on three of SERC's members (Southern Company, TVA, and Progress Energy Carolinas) which represent a portion of SERC-SE, SERC-N, and SERC-E. The information is based on recent IRP information.

  - **SERC-SE: Southern Company**

    Reliability Criterion: Target reserve margin is based on minimizing total system costs to customers.

    Southern Company published an "Economic Study of the System Planning Reserve Margin for the Southern Electric System"[22] in 2009. Based on this report, Southern Company selected a target reserve margin of 15% which approximately minimizes costs and reduces risks to customers.

    To perform this study, Southern used the SERVM model, a resource tool licensed by Astrape Consulting.

  - **SERC-N: TVA**

    Reliability Criterion: Planning reserve margin based on minimizing total system costs to the customer which results in a 15 percent reserve margin.

[22] *Southern Electric Reserve Economic Study of the System Planning Reserve Margin for the Southern Electric System* , retrieved on September 1, 2012 from http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=125981

Based on TVA's 2011 IRP, titled "Integrated Resource Plan, TVA's Environmental and Energy Future"[23]

"TVA identified a planning reserve margin based on minimizing overall cost of reliability to the customer. This reserve margin was based on a stochastic analysis that considered the uncertainty of unit availability, transmission capability, economic growth and weather to compute expected reliability costs. From this analysis a target reserve margin was selected such that the cost of additional reserves plus the cost of reliability events to the customer was minimized. This target or optimal reserve margin was adjusted based on TVA's risk tolerance in producing the reserve margin used for planning studies. Based on this methodology, TVA's current planning reserve margin is 15 percent and is applied during both the summer and winter seasons."

TVA used the SERVM Model to perform its analysis.

- **SERC-E: Progress Energy Carolina**

Based on Progress Energy Carolina's 2012 IRP[24], Progress Energy uses a target reliability of one day in ten years LOLE for generation reliability assessments to set its minimum threshold. The company explains that a 14.5% reserve margin satisfies the one day in ten years LOLE criterion**,** but the company targets a range between 14.5% and 17% based on an economic analysis of total system costs to the customer.

Progress Energy Carolinas used the SERVM Model to perform its analysis in 2012.

- **Southwest Power Pool (SPP)**

Reliability Criterion: Capacity Margin criterion of 12% for RTO members that are steam based and 9% for hydro based; Capacity margins must meet 1 day in 10 Years defined as an LOLH of 2.4 hours per year.

Based on SPP'S 2010 Loss of Load Expectation Report[25], the SPP capacity margin criteria requires each control area within SPP to maintain a 12% capacity margin for steam-based utilities and 9% for hydro based utilities. SPP calculates the LOLE of one day in ten years based on probabilistic modeling and the modeling results show that capacity margins could decrease to 9.6% and still meet this LOLE standard. Based on the study, however, SPP defines one day in ten years differently than the traditional definition. SPP assumes that an LOLH of 2.4 hours per year is 1 day in 10 years instead of one

[23] *Integrated Resource Plan TVA's Environmental & Energy Future*, retreived on September 1, 2012 from http://www.tva.com/environment/reports/irp/pdf/Final_IRP_complete.pdf

[24] *Progress Energy Carolinas Integrated Resource Plan 2012*, retrieved on Dec 1, 2012 from http://www.energy.sc.gov/publications/ProgressEnergyResource%20Plan2012.pdf

[25] *2010 Loss of Load Expectation Report* , retrieved on September 1, 2012 from http://www.spp.org/publications/LOLE%20Report_5%20Draft_cc.pdf

event (0.1 LOLE) in 10 years. The difference is significant because 2.4 hours per year is much less reliable than one event in 10 years.

SPP uses ABB Gridview to assess its reliability.

- **PJM**

  Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

  Based on PJM's 2011 Reserve Requirement Study[26], the reserve margin requirement is 15.5% for the delivery period 2012/2013, 15.3% for the 2013/2014 delivery period, and 15.4% for the 2016/2017 delivery period. The reserve margin requirement supports a generation Loss of Load Expectation (LOLE) of one occurrence in ten years (LOLE = 0.1). PJM references RFC Standard BAL-502-RFC-01[27] as the reason the LOLE metric was adopted. The LOLE target reserve margin and various other calculations provide key inputs into the PJM Reliability Pricing Model (RPM). Through RPM, PJM ensures there are appropriate reserves to meet load. Individual Load Serving Entities (LSE) are not required to provide a specific reserve margin requirement and are allowed to make up shortfalls in the capacity markets. This aspect is much different than areas such as SERC, SPP, and FRCC where load serving entities are responsible for capacity procurement to meet the reliability criterion.

  PJM uses the PRISM model to perform its resource adequacy planning and also uses GE MARS for supplemental modeling.

- **MISO**

  Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

  According to MISO's 2012 Planning Year LOLE Study[28], MISO uses a minimum planning reserve margin of 16.7% across the entire MISO region and is based on meeting a 1-in-10 LOLE target (0.1 LOLE). It is the LSE's responsibility to meet the reserve margin target provided by MISO. The recently approved annual auction allows LSE's to purchase capacity to overcome deficiencies or opt to pay a penalty rather than purchase in the auction. Since the planning reserve margin of 16.7% provided by MISO is a regional reserve margin that doesn't account for load diversity among its members, the target for individual LSEs is 11.3% of its annual peak load. It should also be noted that State Commissions have the authority to set planning reserve margins for their state.

[26] *2011 PJM Reserve Requirement Study,* retrieved on September 1, 2012, from http://www.pjm.com/~/media/committees-groups/subcommittees/raas/20110929/20110929-2011-pjm-reserve-requirement-study.ashx

[27] NERC Planning Resource Adequacy Analysis, retrieved on September 1, 2012, from http://www.nerc.com/files/BAL-502-RFC-02.pdf

[28] *Planning Year 2012 LOLE Study Report,* retrieved on September 2, 2012 from https://www.midwestiso.org/Library/Repository/Study/LOLE/2012%20LOLE%20Study%20Report.pdf

MISO uses the GE MARS model to perform its resource adequacy analysis in combination with PROMOD to establish its zonal areas.

- **NPCC**

All five regions within the NPCC region (NY-ISO, ISO-NE, Maritimes, Quebec, and IESO) require a reserve margin that at a minimum maintains an LOLE of 0.1 days per year. However, there are significant variations in how each area models the details of their system, surrounding regions, load, and other components. There are also differences in the application of the reserve requirements as NY-ISO and ISO-NE maintain resource adequacy through their structured capacity markets.

  - **NPCC-NYISO**

    Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

    Based on the Installed Capacity Requirements study performed by NYSRC in Dec. 2011[29], the required reserve margin to meet the 1-in-10 LOLE standard is 16.1% for the period of May 2012 to April 2013. This study is performed annually to set the annual statewide Installed Capacity Requirement (ICR) for the New York control area. Similar to PJM, these required reserve margin results are used in the NYISO's structured forward capacity markets.

    The LOLE analysis is performed using GE MARS.

  - **NPCC-ISO-NE**

    Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

    ISO-NE is the planning coordinator for the New England Area of the Northeast Power Coordinating Council (NPCC). Similar to PJM and NYISO, the reserve requirements serve as inputs to the structured Forward Capacity Market (FCM) which is used to procure the required amount of installed capacity resources to maintain system reliability. Based on the "New England 2011 Comprehensive Review of Resource Adequacy"[30], required resources are planned based on meeting the NPCC LOLE reliability criterion of no more than one day in ten years disconnection of non-interruptible customers.

    The LOLE analysis is performed using GE MARS.

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[29] *New York Control Area Installed Capacity Requirements For the period May 2012 – April 2013*, retreived on September 2, 2012 from *http*://www.nysrc.org/pdf/Reports/2012%20IRM%20Final%20Report.pdf

[30] *New England 2011 Comprehensive Review of Resource Adequacy*, retrieved on September 2, 2012 from https://www.npcc.org/Library/Resource%20Adequacy/NE_2011_Comprehensive_Review_of_Resource_Adequacy%20-%20RCC%20Approval%20-%2020111129.pdf

- **<u>NPCC-Maritimes</u>**

  Reliability Criterion: Reserve Margin criterion of 20% and 1-in-10 LOLE (0.1 LOLE)

  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. Based on the 2011 Interim Resource Adequacy Review[31], the region meets both of these requirements for 2012 – 2015.

  The LOLE analysis is performed using GE MARS.

- **<u>NPCC-Quebec</u>**

  Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

  Quebec adheres to the NPCC resource adequacy criterion. 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[32]. Because of its dependence on hydro generation to meet peak load, Quebec has also developed an energy criterion stating that sufficient resources should be available to go through a sequence of 2 consecutive years of low water inflows.

  The LOLE analysis is performed using GE MARS.

- **<u>NPCC-IESO (Ontario)</u>**

  Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

  Based on the Ontario Reserve Margin Requirements Report[33], IESO bases its reserve margin requirement on an LOLE of 0.1 days per year. The target for 2013 to meet the one day in 10 year target is 19.7% which the region meets easily with an anticipated reserve margin of 40.1%.

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[31] *2011 Maritimes Area Interim Review of Resource Adequacy*, retrieved on September 2, 2012 from https://www.npcc.org/Library/Resource%20Adequacy/RCC%20Approved%202011%20Maritimes%20Area%20Interim%20Resource%20Adequacy%20Review%20for%20TFCP.pdf

[32] *2011 Quebec Balancing Authority Area Comprehensive Review of Resource Adequacy*, retrieved on September 2, 2012 from https://www.npcc.org/Library/Resource%20Adequacy/Qu%C3%A9bec%20Comprehensive%20Review%202011.pdf

[33] *Ontario Reserve Margin Requirements*, retrieved on September 2, 2012 from http://www.ieso.ca/imoweb/pubs/marketReports/Ontario-Reserve-Margin-Requirements-2012-2016.pdf

- **Sask Power**

  Reliability Criterion: Based on an unspecified expected unserved energy (EUE) criteria.[34]

  Per NERC's 2011 Long Term Resource Assessment (LTRA), Sask Power uses a 13% reserve margin based on probabilistic analysis of Expected Unserved Energy. The specific EUE metric used to set the target was unavailable. This is different than LOLE in that it takes into account the magnitude of the event. NERC has recently recognized the fact that LOLE does not take into account the magnitude of the event and in its latest probabilistic assessments has requested that EUE as a percent of demand be used instead of LOLE.

- **Manitoba**

  Reliability Criterion: Both an energy criterion and a capacity reserve margin criterion due to the fact that the region is predominantly hydro.

  The energy criterion requires adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident river flow conditions are repeated. The reserve margin is at least 12%. Based on Manitoba's 2010/2011 Power Resource Plan[35], Manitoba states that "the reserve margin of 12% has been adequate for Manitoba Hydro's predominantly hydro based system because of the relatively low outage rates of hydro generating units combined with relatively small size units."

- **Mid Continent Area Power Pool (MAPP)**

  Reliability Criterion: 1-in-10 LOLE (0.1 LOLE)

  Per the NERC's 2011 LTRA[36], some of MAPP's members self impose a planning reserve margin of 15% based on the LOLE study performed in 2009.

  Given that the focus of the paper surrounds the Eastern Interconnection, we have only included a few short comments on the ERCOT and WECC interconnections.

3. ERCOT

Reliability Criterion: 1-in-10 LOLE (LOLE of 0.1)

Although ERCOT performs a resource adequacy assessment to determine the reserve margin necessary to meet 1-in-10 LOLE, there is not a mandatory requirement for the region. ERCOT operates as an energy only market and therefore does not have mandatory capacity requirements.

[34] *2011 Long-Term Reliability Assessment,* retrieved on September 2, 2012 from http://www.nerc.com/files/2011LTRA_Final.pdf

[35] *Manitoba Hydro 2010/11 Power Resource Plan,* retrieved on September 3, 2012 from http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2010_2012/Appendix_84.pdf

[36] *2011 Long-Term Reliability Assessment,* retrieved on September 2, 2012 from http://www.nerc.com/files/2011LTRA_Final.pdf

4. WECC

In general, each balancing area has responsibility for meeting resource adequacy standards established by respective states in which they operate. Resource adequacy planning in WECC is similar to that in SERC.

- **CAISO**

The California ISO uses a resource adequacy requirement of 15% reserve margin set by the California Public Utility Commission's Resource Adequacy Program. It is our understanding that the 15% was derived from previous resource adequacy studies.

- **NWPP**

The Pacific Northwest uses an LOLP metric that states the following: "the likelihood of having at least one curtailment five years into the future must be 5% or less for the power supply to be deemed adequate."[37] They also include another metric 2) conditional value at risk (CVaR) to evaluate the likelihood, magnitude, duration, and seasonality of Energy-Not-Served (ENS) events.

[37] Fazio, John, *Pacific Northwest Resource Adequacy Standard*, retrieved on September 3, 2012 from http://ewh.ieee.org/cmte/pes/rrpa/RRPA_files/LBP20120726/Item%2011%20-%20IEEE%20RRPA%20PNW%20Adequacy%2072712.pdf

III. PREVIOUS ECONOMIC STUDIES OF THE 1 DAY IN 10 YEAR STANDARD

A number of studies have been performed that evaluate the value of service reliability. The most common approach taken in these studies compares the direct and indirect costs of outages with the costs of generating capacity at a range of reserve margins. Some of the studies also take into account other benefits of reserve capacity including reduced purchase costs, offsetting higher cost resources, reducing the costs of voltage reduction, and reducing the costs of interrupting non-firm load customers. However, few of the studies surveyed explicitly estimate the reasonableness of existing physical reliability standards by comparing to economically optimal reserve margins. This is likely because the units of physical reliability events do not reflect their magnitude or duration. The cost of 1 event in 10 years is highly dependent on the size and duration of the event, neither of which is reflected in the metric. The following sections review specific studies of the value of service reliability.

A. ECONOMICS OF RELIABILITY FOR ELECTRIC GENERATION SYSTEMS (1973)

M.L. Telson's thesis titled the Economics of Reliability for Electric Generation Systems in 1973[38] was one of the earliest relevant studies which specifically addressed the reasonableness of physical reliability standards. His approach was similar to many of the other value of electric service studies which approximate an optimum reserve margin by comparing the cost of carrying additional capacity with the costs of outages at various reserve margins. Since his approach is used frequently, we will analyze it in some depth.

Mr. Telson does explicitly compare economically optimal reserve margins with reserve margins determined by physical metrics such as the 1-in-10 LOLE metric. His analysis suggests that reserve margins set by 1-in-10 LOLE are much higher than would be justified by an economic analysis. An economically set reserve margin might provide reliability as low as 1 event per year according to his analysis. A simplification of the related math states that 1 event per year with an outage cost of ~$1/kWh and a duration of 12 hours is comparable to the carrying cost of a new unit at $12/kW-yr. This is the optimal level because additional reserves would provide less than $12/kW-yr of avoided outages, and fewer reserves would result in more than $12/kW-yr of additional outages. Mr. Telson's analysis suggests that under typical reliability standards, customers are over-paying on a total cost basis by 4.1% compared to what they would pay under an economically optimal reserve margin even after considering societal outage costs. While the cost figures from 1973 are no longer applicable, more recent studies also make the point that it would take several hours per year of outages even with high outage costs to justify new capacity.

As additional support for a lower reserve margin target than indicated by the 1-in-10 LOLE standard, Mr. Telson compares generation adequacy related outages with transmission and distribution outages which are orders of magnitude more frequent. This report also highlights the conservative assumptions built into many of the 1-in-10 LOLE based reliability studies. Another limitation pointed out by Mr. Telson of most physical reliability studies is their lack of attention to the magnitude and duration of outages.

The support for Mr. Telson's position that an economic reserve margin should be less than a 1-in-10 LOLE target is dependent on the system conditions he assumed, many of which are not applicable to systems today. For example, in the early 1970's, load growth was

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[38] *Economics of Reliability for Electric Generation Systems*, M.L. Telson, 1973

much higher with substantial uncertainty; unit performance was less reliable, the carrying cost of additional reserves was higher in real terms, and the cost of outages was lower in real terms. However, even with updated assumptions, we do not feel that Mr. Telson's approach considers all of the economic factors necessary for valuing the benefits of additional capacity. In fairness, his economic analysis is much more sophisticated than suggested by our example and includes a number of indirect economic impacts in addition to the direct costs mentioned.

B. COST AND BENEFITS OF OVER/UNDER CAPACITY IN ELECTRIC POWER SYSTEM PLANNING (1978)

Another early significant study in our research results is titled 'Costs and Benefits of Over/Under Capacity in Electric Power System Planning' and was performed for EPRI in 1978[39]. This study analyzed the economics of generation reliability for 4 utilities (Tennessee Valley Authority, Pacific Gas and Electric, Long Island Lighting Company, and Wisconsin Electric Power Company). This study uses a number of unique assumptions:

1. Load growth and capacity expansion uncertainty are primary drivers of the need for planning reserves. This is primarily a function of the high load growth period of the 1970's and is likely not applicable today.
2. Total variable costs for each different reserve margin level studied must be incorporated into the total cost comparison; not just the outage costs and capital costs. This analysis included the variable production costs of each unit plus the cost of purchasing electricity from interties, interrupting certain customers, and reducing voltage.
3. Environmental cost differences between different reliability levels should also be considered. While the costs were not explicitly included in the analysis, qualitative consideration was given to the environmental benefits or penalties at different levels of service reliability.

The study also results in a number of unique observations:

1. Asymmetry of Consumer Cost. Reserve margins much below the optimal reserve margin tend to have much higher costs than reserve margins much above the optimal reserve margin. This suggests that if two reserve margin levels have the same expected value, the higher reserve margin is a more appropriate selection based on its lower risk profile.
2. The total cost curve is relatively flat at a wide range of reserve margins near the optimal economic reserve margin. This also supports carrying higher reserve margins since the cost differences are not substantial.
3. The economically optimal reserve margin can vary substantially depending on the resource mix, unit performance, load and load growth profile, and other factors. The optimum reserve margins for the 4 utilities studied ranged by approximately 15%.

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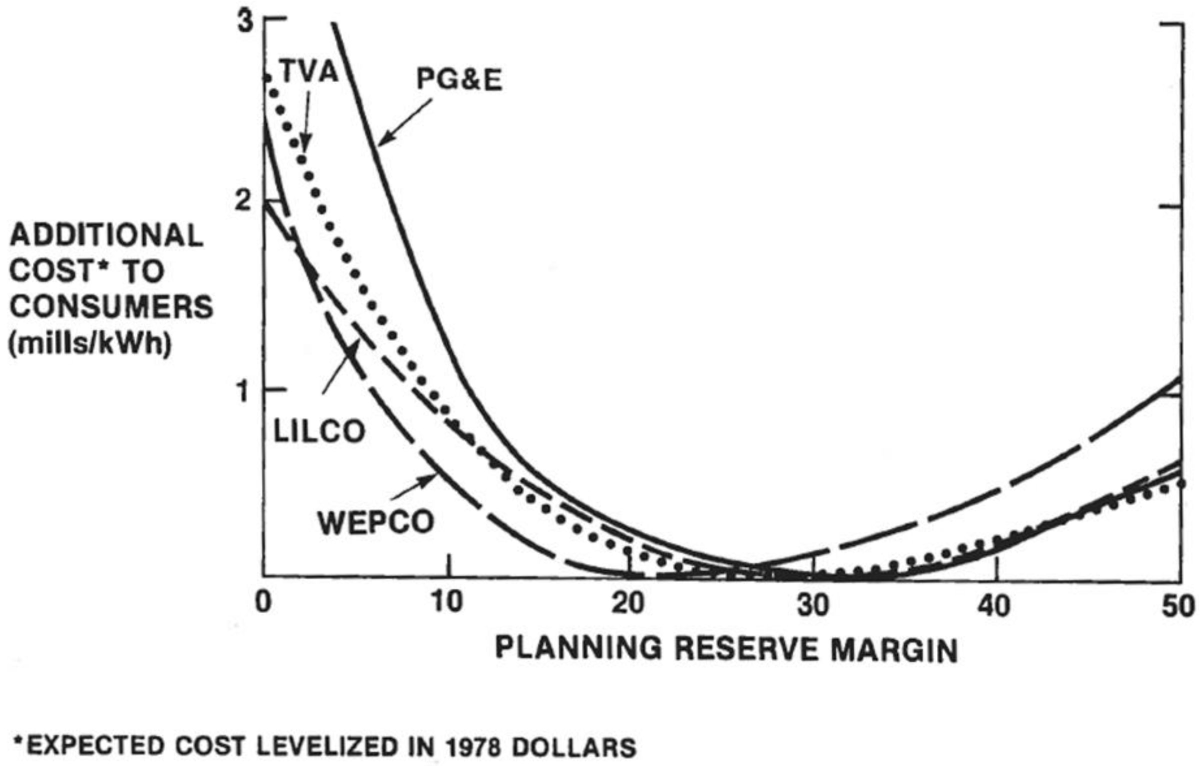
[39] Decision Focus, Incorporated, *Costs and Benefits of Over/Under Capacity in Electric Power System Planning*, EPRI EA-927, Project 1107, October 1978

4. Old technologies can have a substantial impact on the economically optimal reserve margin. If the marginal unit used to increase or decrease reserves has an operating cost less than a substantial portion of a utility's existing resources, the economically optimal reserve margin may be quite high. Regardless of how high the reserve margin is, as long as adding resources is offsetting the dispatch of a significant portion of existing resources, their addition could be economic.

The results of the analysis indicate that reasonable economic reserve margins fall in the range of 15% to 40% as shown in the Figure 2 below. While the study did not explicitly compare these reserve margin levels to 1-in-10 LOLE based reserve margins, the paper suggests that economic reserve margins are not necessarily lower than reserve margins determined by physical reliability metrics. Further, even at reserve margins above those standards, the additional costs are not that substantial. This conclusion is counter to a number of other value of service studies that indicate that economically set reserve margins are always lower than 1-in-10 LOLE based reserve margins.

Figure 2. Total Costs as a Function of Planning Reserve Margin

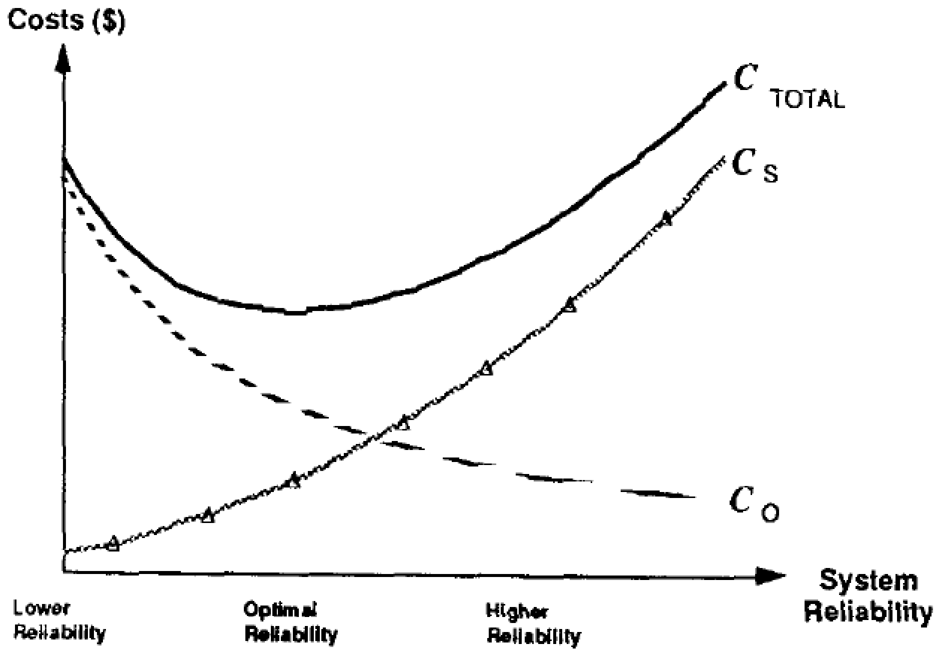


C. PGE VALUE OF SERVICE RELIABILITY (1990)

In 1990 Sandra Burns and Dr. George Gross authored a paper called Value of Service Reliability[40] that studied the Value of Service approach to resource adequacy planning. Ms. Burns and Dr. Gross begin by stating valid points why physical metrics such as LOLE and LOLP are somewhat arbitrary and don't take into account the economic impact on customers. For example the paper said "it is difficult to determine from a societal point of view whether a 1 day in 10 years LOLP is more appropriate than 1 day in 5 years or 1 day in 20 years."

Next the paper discussed the Value of Service framework in which the marginal costs of additional reserves are compared against the marginal benefit of additional reserves. Figure 3 summarizes this method. Co represents cost to customers when demand cannot be met and Cs represents capital investment expenditures. As reliability increases (or reserve margin increases), investment expenditures increase while customer costs due to the utility not meeting demand decrease. At some point the benefit of the additional capacity is not justified.

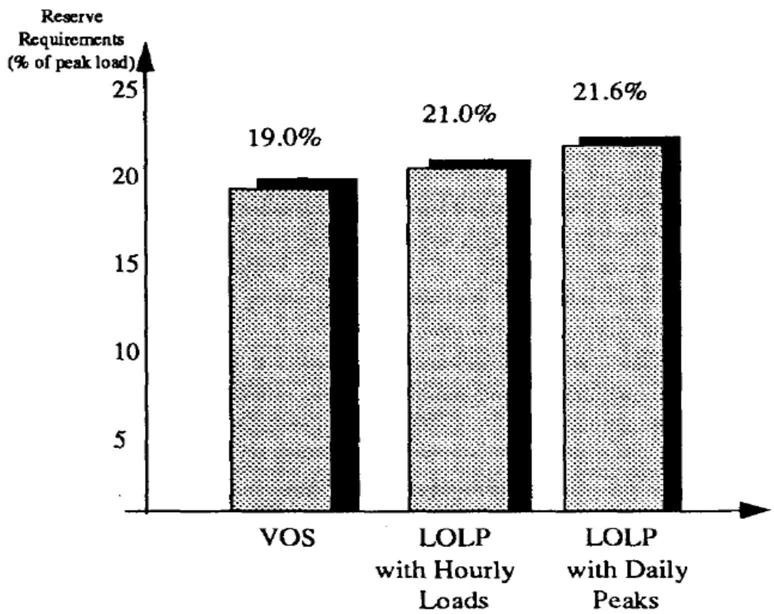
Figure 3. Variation of Costs as a function of reliability



To develop a proper estimate for Co, PGE used recent customer outage surveys which resulted in a weighted average customer cost of $3/kWh. Next, the author compared the economic approach to two different physical reliability metrics. The first approach used hourly loads and calculated the reserve margin assuming an LOLH of 2.4 hours per year while the second method used daily peaks to calculate an LOLE of 0.1 days per year. The results are seen in Figure 4. The economic approach produced a lower reserve margin than the traditional physical reliability approaches.

[40] Burns, Sandra and Gross, George, *Value of Service Reliability,* IEEE Transactions on Power Systems, Vol.5, No.3, August 1990

Figure 4. Value of Service vs. LOLP



The study implies a general relationship that a reserve margin based on value of service would be less than the 1-in-10 LOLE metric.

D. On an 'Energy Only' Electricity Market Design for Resource Adequacy (2005)

While this paper[41] by William Hogan was not specifically designed to address the economic reasonableness of using specific physical reliability metrics to set target reserve margins, it does address resource adequacy and the missing money problem in structured markets. Mr. Hogan's paper provides informative insights into the economics of resource adequacy from the perspective of generators. He proposes a number of improvements to the design of energy markets that could alleviate the need for additional capacity payments and still provide generators adequate revenue to cover their costs. He recognizes that in current markets, many generators do not fully recover their costs. His explanation for this gap is that "the missing money problem arises when occasional market price increases are limited by administrative actions such as price caps." While we agree that price caps are certainly a component of missing money, in the absence of a reserve margin target, generators theoretically should offer less capacity to the market such that, even with the price caps in place, generators still receive adequate revenue. Imagine a system with price caps at $500/MWh. With this low cap, fewer generating assets should be built since they can't expect adequate returns at a higher reserve margin. This lower reserve margin will result in scarcity situations more frequently producing adequate returns for marginal generators, however the tradeoff would be that physical reliability would decline.

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[41] Hogan, William (2005), "On an “Energy Only” Electricity Market Design for Resource Adequacy."

We are not suggesting that an energy market with low price caps is an ideal market structure. We are simply illustrating that regardless of market structure, generators should theoretically target a reserve margin that produces adequate returns regardless of the reliability implications.

One aspect of Hogan's solution for the missing money problem is to eliminate price caps and implement an administrative scarcity pricing curve. He states: "For any level of capacity that provides a given level of reliability, there is some set of shortage prices that would produce generator revenue streams that if correctly anticipated would be sufficient to sustain that level of capacity." While this is a valuable insight, it does not speak to whether the given level of reliability is economically appropriate. Hypothetically, the given level of reliability could require a 30% reserve margin. The administrative scarcity pricing curve would have to be extremely high, well above the true value of the reserves, in order to achieve cost recovery.

E. Reconsidering Resource Adequacy: Has the one-day-in-10-years criterion outlived its usefulness? (2010)

Mr. James Wilson recently published an article[42] in the Public Utilities Fortnightly examining the one-day-in-ten year standard and whether or not it was economic. Mr. Wilson states "The 1-in-10 criterion always has been highly conservative--perhaps an order of magnitude more stringent than the marginal benefits of incremental capacity can justify—and capacity planning has been even more conservative in practice." He uses examples comparing the Value of Lost Load x LOLE x hours per event to Net Cost of New Entry (CONE) which represents the capital costs of a new combustion turbine net of energy and ancillary service revenues as shown in the table below. Utilizing the examples, in all cases the optimal amount of LOLE is higher than the 0.1 LOLE standard as shown in the following table. For example, in order to justify a $120,000/MW-year Net CONE, the resource must offset 6 LOLE events per year assuming 5 hours per event and a VOLL of $4,000/MWh. (Note: the units from the article for VOLL should be $/MWh and the units of Net Cone should be $/MW-yr)

[42] Wilson, James, *Reconsidering Resource Adequacy,* retrieved on September 4, 2012 from http://www.fortnightly.com/uploads/04012010_ResourceAdequacyP11.pdf

Table 3. Optimal LOLEs for Various VOLL and Capital Cost Assumptions

Value of service (VOLL)	Net Capital Cost (Net CONE)	Hours per outage event	Optimal LOLE	Optimal Nines
$/MW-year	$/MWH	hours/event	events/yr	
$4,000	$120,000	5	6.0	2.5
$4,000	$80,000	5	4.0	2.6
$4,000	$40,000	5	2.0	2.9
$2,000	$120,000	5	12.0	2.2
$2,000	$80,000	5	8.0	2.3
$2,000	$40,000	5	4.0	2.6
$20,000	$120,000	5	1.2	3.2
$20,000	$80,000	5	0.8	3.3
$20,000	$40,000	5	0.4	3.6

Moreover, Mr. Wilson states the following: "The tendency is often to adopt conservative assumptions for many of these values, to make the overall result of the analysis conservative (i.e. erring on the side of too much rather than too little capacity and reliability, identifying too large rather than too small a reserve margin)." In conclusion, Mr. Wilson argues that the 1-in-10 LOLE standard is not an economic target and that economics would indicate much lower target reserve margins.

Mr. Wilson's article is primarily targeted toward the PJM system. In agreement with his assessment of PJM, our review of regions in the Eastern Interconnection indicates that PJM's planning study assumptions are potentially conservative. However, in concurrence with our other assessments, we believe that Mr. Wilson is not including some key components of the value of marginal capacity in his analysis. A marginal resource provides substantially more value than simply displacing firm load shed events.

F. The Economics of Resource Adequacy Planning: Why Reserve Margins Are Not Just About Keeping the Lights On (2010)

Astrape Consulting cooperated with the Brattle Group to write the paper titled "The Economics of Resource Adequacy Planning"[43] which was published by NRRI in April of 2011.

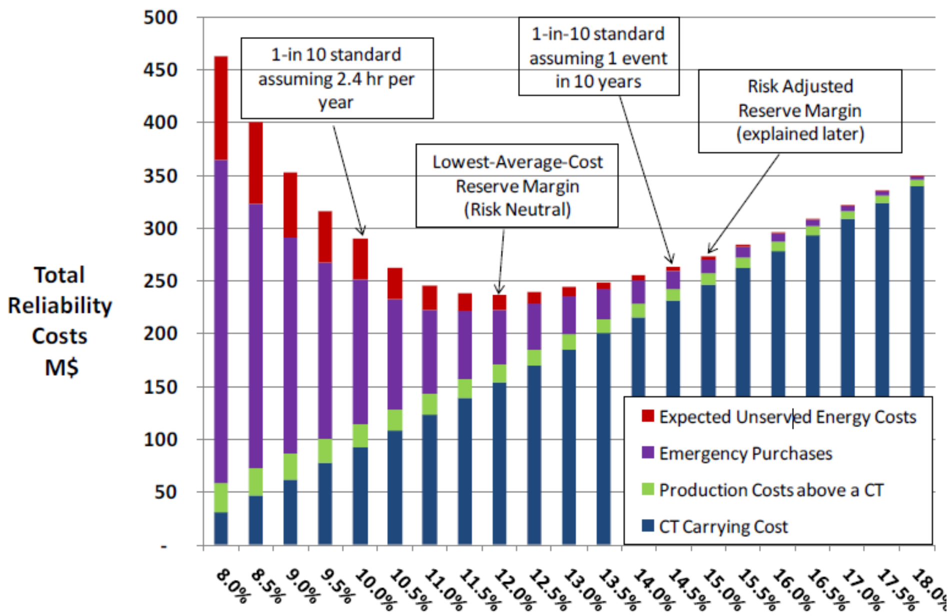
The paper describes an economic approach to resource adequacy planning and compares it to results utilizing two different definitions of the 1-in-10 LOLE standard. The authors develop a case study using a resource adequacy model that not only calculated LOLE but also takes into account economic dispatch and costs. The methodology balances the cost of new capacity (CT) with the benefit the resource provides. In this study, the benefit is defined as the following:

[43] Carden, Pfeifenberger, Wintermantel, *The Economics of Resource Adequacy Planning: Why Reserve Margins Are Not Just About Keeping the Lights On, NRRI, April 2011, retrieved on September 3, 2012 from* http://www.nrri.org/pubs/electricity/NRRI_resource_adequacy_planning_april11-09.pdf

- Production-Related Reliability Costs – defined as any costs of the system's physical generation above the dispatch cost of the new capacity resource. This includes the dispatch of higher-cost generators such as oil-fired turbines and old natural gas turbine units. The addition of a new capacity resource would offset some but not all of these costs.
- Emergency Purchase Costs – defined as the costs of any purchases at prices higher than the cost of the marginal capacity resource. In our simulations, these emergency purchase costs, including purchases associated with demand-side resources, can range from $1/MWh above the dispatch cost of a CT to the cost of unserved energy (*e.g.*, well in excess of $1,000/MWh) under extreme conditions.
- Unserved Energy Costs – The value of lost load to customers. This value typically is derived from customer surveys.

The point is made that the majority of costs from the California Energy Crisis were comprised of expensive energy prices in the marketplace and not due to firm load shed. A marginal resource has the ability to reduce scarcity pricing events as well as reduce firm load shed events. The results of the study are seen below. The economic reserve margin target (Lowest-Average-Cost Reserve Margin) was higher than a 2.4 LOLH based reserve margin and lower than a 1-in-10 LOLE based reserve margin. The authors make the point that dependent on the system, the economic reserve margin could be higher or lower than the 1-in-10 LOLE target.

Figure 5. Lowest Average Cost Reserve Margin



The fundamental distinction of this study is that there is a significant focus on the costs of emergency purchases and the impact of scarcity pricing in markets. Dependent on the severity of the weather and load forecast uncertainty in a particular case, it is reasonable to assume that a CT could be dispatched 0 hours up to 1,500 hours in a given year. In years where a CT is dispatched substantially, it is important to recognize all the benefits the resource provides. Alongside the weighted average or expected results, the authors discuss the importance of understanding the full distribution of potential costs from all scenarios comprised of combinations of weather and load forecast uncertainty. Given that reliability events are low-probability high-impact events, the tails of the distribution of possible scenarios are important.

One of the critiques of the approach put forward by Brattle and Astrape is that there was no weather diversity considered causing the scarcity pricing to be too high, and that the load forecast error distribution assumed provides limited flexibility in adjusting resource plans if load grows faster than expected. Reviewers have suggested that the conservative nature of these assumptions led to higher than optimal reserve margins. These critiques have been considered by the authors and have been incorporated in the simulations for this white paper. For example, each region's load was modeled based on hourly historical weather to ensure proper weather diversity is taken into account.

Additional Scholarly Works that Address the Economics of Reliability:

- Electric Utility System Reliability Analysis: Determining the Need for Generating Capacity (1988) by Biewald and Bernow
- Reliability Evaluations of Power Systems, Billinton (1990)
- Southern Company Reserve Margin Studies (1997, 2004, 2007, 2009)
- Louisville Gas and Electric Reserve Margin Study (2010)
- Peter Cramton and Steven Stoft (2006), "The Convergence of Market Designs for Adequate Generating Capacity."

In summary, we reviewed multiple economic studies which assessed the reasonableness of the 1-in-10 LOLE standard and summarized the findings of 6 of those studies. The EPRI Over/Under study and the study produced by Astrape Consulting/The Brattle Group demonstrated economic target reserve margins that could be below or above LOLE 1 day in 10 year targets. The remaining studies (Telson, PGE VOS, Wilson) all implied that the economic target would likely be lower than the 1-in-10 LOLE target. Given the sensitivity of the results to input assumptions, it is likely that changes to the cost of carrying capacity, the value of lost load, and load uncertainty since some of those studies were published would affect conclusions. Further, in reviewing methodologies, the major difference was defining the benefits that a marginal resource provides. The benefits defined varied across the studies from including all costs above the dispatch cost of a CT (i.e. emergency purchases, DR costs, and unserved energy) to only including the Value of Lost Load to customers.

Economists may argue that the economic optimal target should only be based on total societal costs which would include only total production costs (fuel burn + O&M) plus the cost of unserved energy and ignore the scarcity pricing situations that occur in the market place. The argument is that these high cost purchases only represent a transfer of wealth from one region to another or from customers to generators rather than an actual societal cost. However, the approach of only considering net societal costs largely ignores the bigger question of how costs and revenues are shared among the participants in the system. Assume an example system minimizes total societal costs at a reserve margin of 8%, and at this level total societal costs annually are $5 billion in fuel, O&M, and capital costs. When the economics of each participant are considered however, there may be significant market distortions. If this was an energy-only system and reserves approximately matched the minimum societal cost reserve margin of 8%, significant scarcity would be prevalent. The market price in many hours would be set by scarcity pricing even though the total production costs are still minimized at this low reserve margin. Because of this scarcity, generators may extract $8 billion in energy costs from consumers in a given year, a $3 billion transfer of wealth. This is ignored in the societal cost minimization approach, but represents a significant concern.

In competitive markets, if there is a distortion resulting in a transfer of wealth from consumers to generators, then new generation would theoretically enter the market until the marginal unit is only recovering its costs. The new capacity would raise the reserve margin and eliminate the wealth transfer. But now the system is no longer targeting the optimum reserve margin based on minimizing societal costs. The reserve margin target becomes the level at which generators recover costs. But as we will discuss in later sections of the report, total systems costs in an energy only market at the point of generator cost recovery may not be optimal when compared to other potential market structures.

The minimization of net societal costs approach is instructive in a number of ways. If an entire system consists only of vertically integrated utilities, and all transfers are passed on to customers at cost, and planning is coordinated between all utilities, the minimization of net societal costs is theoretically correct. The results from such an analysis could be compared to the minimum customer cost approach for a single utility to identify the magnitude of the inefficiency due to not coordinating all planning activities.

IV. VOLL ESTIMATES AND THEIR IMPACT ON RESOURCE ADEQUACY PLANNING

Over the last several decades, there have been many customer surveys and studies performed to estimate the value of lost load to customers. Two comprehensive studies which aggregated many of the individual surveys were performed for the U.S. Department of Energy (DOE) by Ernest Orlando Lawrence Berkeley National Laboratory in November 2003 and updated again in June 2009[44]. For this analysis, we will focus on the results from the June 2009 study. The study takes results from 28 customer value of service reliability studies conducted by 10 major US electric utilities over the 16 year period from 1989 to 2005. The majority of these studies are not available publicly and were only made available by utilities for this specific DOE study. The results were combined into a single meta-database and a regression model was developed to calculate customer costs per event by season, time of day, day of week, and geographical regions within the U.S.

The study divided customer groups into the following:

- Medium and Large Commercial and Industrial (more than 50,000 annual kWh usage)
- Small Commercial and Industrial (less than 50,000 annual kWh usage)
- Residential Customers

The following tables summarize the data found in the study.

Table 4. Value of Lost Load Summary: Summer Weekday Afternoon

Interruption Cost $/event	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I	$ 11,756	$ 15,709	$ 20,360	$ 59,188	$ 93,890
Small C&I	$ 439	$ 610	$ 818	$ 2,696	$ 4,768
Residential	$ 2.70	$ 3.30	$ 3.90	$ 7.80	$ 10.70

$/kWh Unserved Energy at Customer Peak*	Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I		$ 30.83	$ 19.98	$ 14.52	$ 11.52
Small C&I		$ 85.50	$ 57.33	$ 47.23	$ 41.77
Residential		$ 1.30	$ 0.77	$ 0.38	$ 0.26

[44] Ernest Orlando Lawrence Berkeley National Laboratory, *Estimated Value of Service Reliability for Electric Utility Customers in the United States*, June 2009

*Peak Loads used to calculate interruption costs in $/kWh for each customer class were based on reported average kWh energy use and assumed an 80% load factor for medium and large customers, 40% load factor for small customers, and 30% load factor for residential[45]

In performing economic resource adequacy analysis, the $/kWh value associated with unserved energy at peak is the value that is typically used as the Value of Lost Load assumption. Assuming that firm load shed would be spread equitably among all customer classes, a weighted average of the system's customer class mix can be calculated to develop a system $/kWh value for the region being studied. The weighted average $/kWh for Unserved Energy using the 1 hour values is $26.02/kWh.

The table shows that as the duration of the outage increases, the $/kWh value decreases. The first hour is typically the most expensive as customers have an opportunity to mitigate the impact of an outage in subsequent hours. The results also show that Residential Customers have the lowest costs while Small C&I Customers have the greatest costs. This is logical as residential customers generally only have some discomfort and minor loss such as spoiled food during outages. We typically see the VOLL for residential customers to be less than $3/kWh. Businesses have a much higher cost. Technology has been a major driver for the increase in commercial business outage costs as computer systems have become so vital in today's work environment. For retail business, there is lost sales revenue as businesses may be forced to close during the outage. For industrial customers, the costs of lost product and lost revenue drive the estimates.

The next table shows how outage costs varied by season, day of week, region, and industry. It is seen that depending on the industry and size of the business, the VOLL can vary greatly. For Medium and Large C&I Customers, the outage costs can vary from $2.8/kWh to $40.9/kWh depending on the industry. For Small C&I Customers, costs range from $21.7/kWh to $108.7/kWh. VOLL is an uncertain value, but as our case study demonstrates, the assumption does not have a significant impact on the economics of resource adequacy. In a system that is planning to the 1-in-10 LOLE standard, the amount of expected unserved energy (EUE) is small and therefore limits its impact on economic results. While the raw average estimates from the aggregated studies indicated a much higher VOLL, due to the large variance in VOLL estimates, $15,000/MWh was assumed in the case study as a blended rate for residential, commercial, and industrial customers.

[45] Ernest Orlando Lawrence Berkeley National Laboratory, *Estimated Value of Service Reliability for Electric Utility Customers in the United States*, June 2009; Table ES-1 costs per event were converted to $/kWh based on the peak load assumption for each customer class.

Table 5. Cost per Event across Season, Day, Region, and Industry[46]

	Cost per Event of 1-Hour Outage					
	Medium and Large Commercial and Industrial Customers 2008$		Small Commercial and Industrial Customers 2008$		Residential Customers 2008$	
Season	Costs $	$/kWh*	Costs $	$/kWh*	Costs $	$/kWh*
Winter	$ 11,129	$ 10.9	$ 543	$ 38.1	2.9	$ 0.6
Summer	$ 15,628	$ 15.3	$ 737	$ 51.6	4.7	$ 0.9
Day						
Weekend	$ 2,249	$ 2.2	$ 459	$ 32.2	8.6	$ 1.7
Weekday	$ 16,478	$ 16.2	$ 765	$ 53.6	4	$ 0.8
Region						
Midwest	$ 12,294	$ 12.1	$ 732	$ 51.3		
Northwest	$ 3,552	$ 3.5	$ 341	$ 23.9	3.2	$ 0.6
Southeast	$ 23,797	$ 23.4	$ 799	$ 56.0	6.6	$ 1.3
Southwest	$ 5,946	$ 5.8	$ 967	$ 67.8	1.8	$ 0.4
West	$ 18,166	$ 17.8	$ 886	$ 62.1	3.7	$ 0.7
Industry						
Agriculture	$ 1,063	$ 1.0	$ 352	$ 24.7		
Mining	$ 18,501	$ 18.2	$ 1,545	$ 108.3		
Construction	$ 3,663	$ 3.6	$ 1,301	$ 91.2		
Manufacturing	$ 41,691	$ 40.9	$ 913	$ 64.0		
Telco. & Utilities	$ 8,837	$ 8.7	$ 810	$ 56.8		
Trade & Retail	$ 2,818	$ 2.8	$ 627	$ 43.9		
Fin., Ins. & R.E.	$ 5,790	$ 5.7	$ 975	$ 68.3		
Services	$ 4,810	$ 4.7	$ 531	$ 37.2		
Public Admin	$ 12,239	$ 12.0	$ 310	$ 21.7		

*Peak Loads for each customer class were based on the report's average kWh energy use and assumed an 80% load factor for medium and large customers, 40% load factor for small customers, and 30% load factor for residential [47]

Based on the variation of VOLL values provided by businesses, it is easy to recognize the need for demand response programs with different characteristics. For a customer with very low outage costs, it would be rational for them to curtail load when prices reach a threshold of $150/MWh while a customer who has high outage costs and no backup generation would likely not participate in a program. As part of the simulation portion of this paper, we analyze what happens to reliability as the penetration of demand resources increase without increasing the dispatch constraints. As DR penetration increases, energy prices will increase and DR resources will be called upon much more frequently. The estimation of

[46] No studies available to be summarized for black shaded cells.

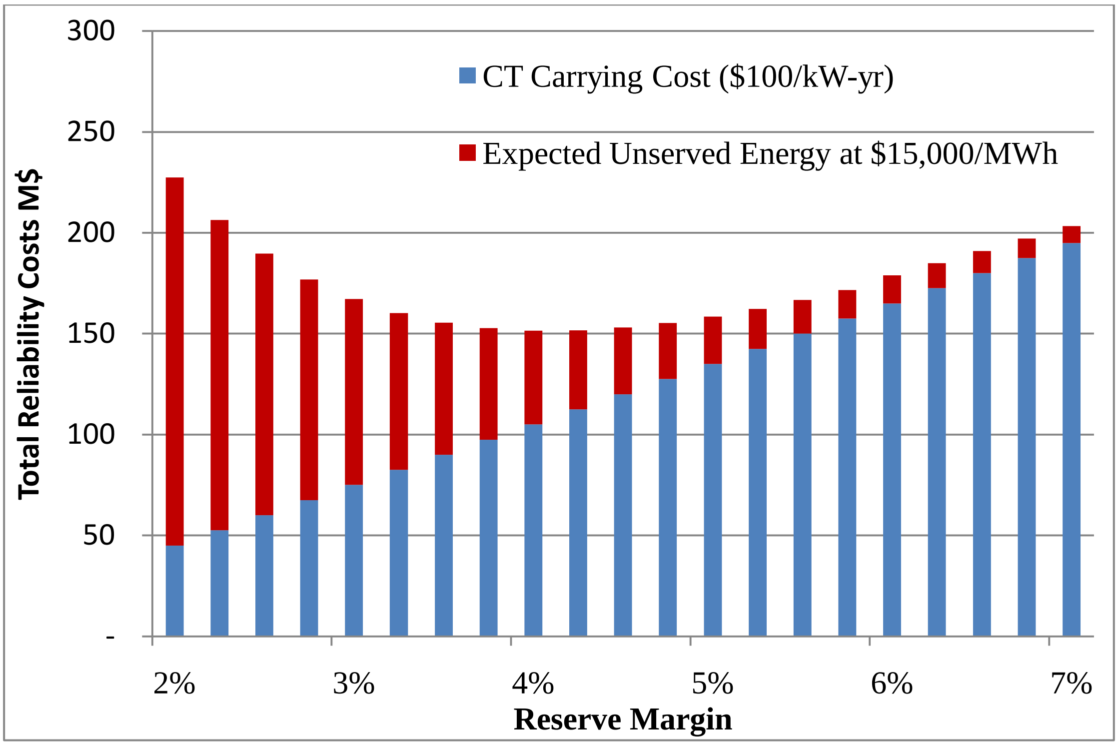
[47] Ernest Orlando Lawrence Berkeley National Laboratory, *Estimated Value of Service Reliability for Electric Utility Customers in the United States*, June 2009; Table 3-4, Table 4-4, and Table 5-4 average costs per event were converted to $/kWh based on the peak load assumption for each customer class.

these calls is going to be vital to resource adequacy planning in the next decade, particularly because DR resource participants are voluntary participants who may choose to discontinue participation if DR resource use hits thresholds of tolerance.

V. DETERMINING THE OPTIMAL RISK NEUTRAL AND RISK ADJUSTED ECONOMIC RESERVE MARGIN

Most of the research papers cited in Section III compared the cost of incremental capacity to the economic benefit of reduced unserved energy costs provided by the capacity under a vertically integrated utility environment. As an example of this methodology, if adding new capacity costs $100/kW-yr, and the value of lost load is $15,000/MWh, the new capacity would need to offset more than 6 hours of lost load per year to be economically justified. However, since the 1-in-10 LOLE standard represents only 0.3 hours of lost load per year, the economic reserve margin would be much lower than the 1-in-10 LOLE based reserve margin as shown in the Figure 6 below. The economic reserve margin is 4% in our case study if only EUE is taken into consideration as the benefit additional capacity provides. Again, this is the economic reserve margin for this particular analysis because adding capacity up to a 4% reserve margin costs less than the economic societal benefits of reduced EUE for this region. Above a 4% reserve margin, adding capacity costs more than the economic societal benefits produced in reducing EUE. A 4% reserve margin results in the minimum capacity plus EUE costs.

Figure 6. Cost of Capacity vs. Reduction in Expected Unserved Energy Costs



However, system planners should be attempting to minimize total system costs to customers, not just a subset of system costs. Every benefit of incremental capacity should be considered. In addition to avoiding the societal costs of shedding firm load, adding new efficient gas turbines would avoid the dispatch cost of many inefficient existing units and avoid expensive market purchases during hours when capacity is scarce. When taking these additional benefits into consideration, total system costs continue to drop as capacity is added well above a 4% reserve margin.

In the following case study we will explore potential methods of determining a risk neutral and optimal risk adjusted target based on total system costs to customers.

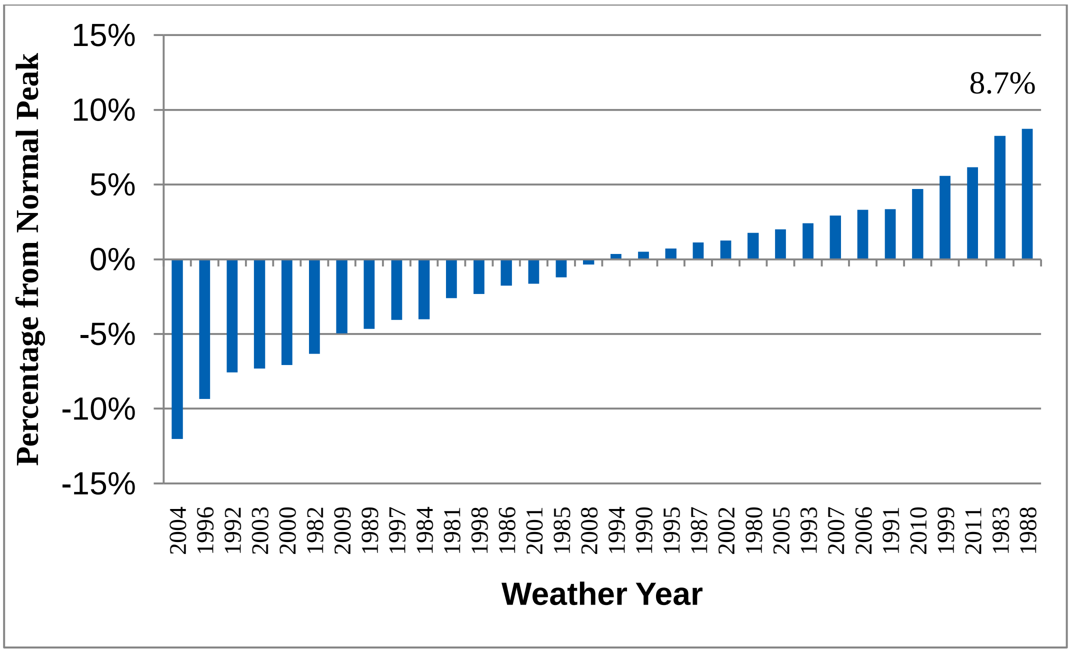
A. Case Study Description

The following is a brief overview of the case study setup. The Eastern Interconnection Planning Collaborative (EIPC) has recently performed its Eastern Interconnection Transmission Study. The primary objective of the EIPC study was to aggregate the modeling and regional transmission expansion plans of the entire Eastern Interconnection and to perform regional analyses to identify potential conflicts and opportunities between regions. The EIPC study simulates all loads, generating resources, and transmission resources for all individual regions. Input data for the case study presented in this report uses data from the EIPC study as inputs, including region definitions, load forecasts, generating resource mixes, and transmission capabilities. Because the scope of this white paper was limited, only a subset of 14 of the NEEM regions from the EIPC study was included. For resource adequacy studies, accurate representation of the uncertainty in loads and generator availability is necessary to capture the frequency of reliability events. Firm load shed and extremely high market prices are typically only concerns when loads are much higher than normal or generating resources are less available than normal.

To accommodate this additional uncertainty, we included distributions around the following variables:

- Weather Uncertainty. Figure 7 demonstrates that summer peak load could be as much as 8.7% higher than normal peak load due to weather uncertainty in the PJM Rest of MAAC (PJM ROM) region. This is fairly typical across most of the regions in the Eastern Interconnection. Weather also impacts hydro, thermal, and intermittent resources which was also captured in the case study (See Appendix A).

Figure 7. Weather Impact on Peak Load for PJM Rest of MAAC



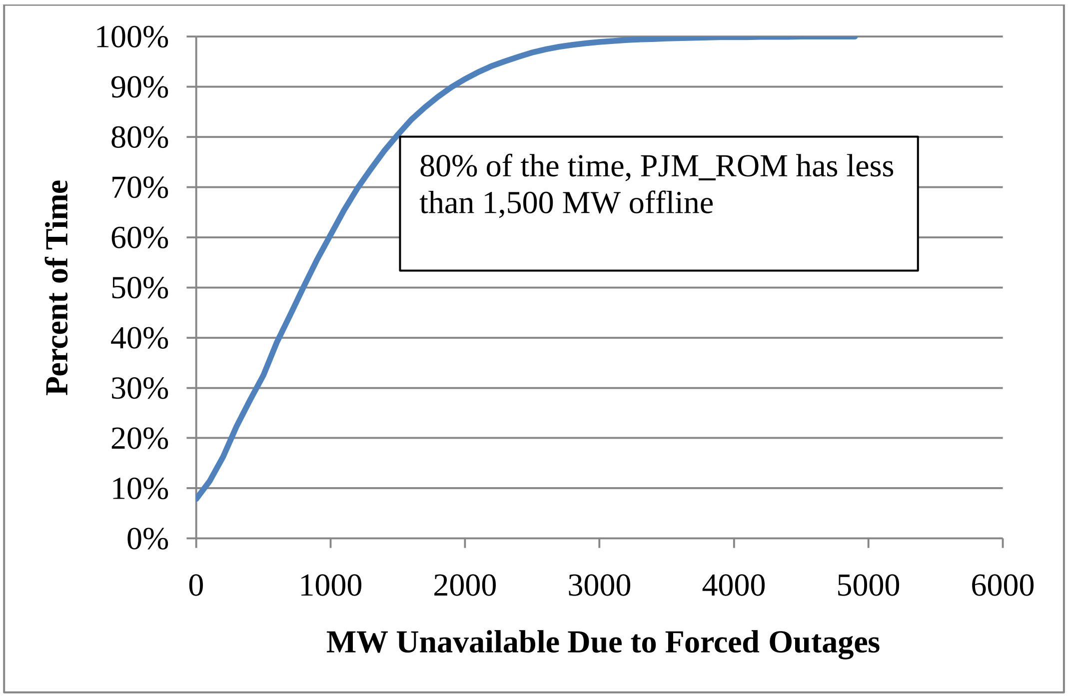
- Load Forecast Uncertainty. All loads for a given year could be as high as 5% higher (although this has a very low probability of occurring) than normal due to unexpected economic growth over a 4 year period as seen in the distribution in the Figure 8. The 6 discrete points in the table with associated probabilities were used in the simulation. This economic uncertainty captures the boom-bust cycle inherent in electric markets. Some years the market will have excess capacity above the target reserve margin and other years markets will be below the target reserve margin. This error distribution was developed from analyzing how well the Congressional Budget Office was able to forecast GDP three to four year out. That distribution of performance was translated to electric demand using a multiplier of .4% load growth for every 1% of GDP growth. The development of this distribution is further explained in the Appendix A.

Figure 8. Economic Load Forecast Error

Load Forecast Error	Probability
5.11%	6.25%
3.90%	18.75%
0.55%	31.25%
-1.76%	18.75%
-2.90%	12.50%
-4.54%	12.50%

- Unit Performance Uncertainty. Figure 9 shows that the study system is expected to have approximately 800 MWs in a forced offline state on average, but there are hours in which the system could have 2,000 MWs offline. The figure also shows that 80% of the time the region will have less than 1,500 MW offline due to forced outages.

Figure 9. Unit Performance Distribution



Additional modeling details can be found in Appendix A.

Each scenario modeled in SERVM[48] consists of one economic forecast error point and one weather year. The first scenario simulated used 1980 historical weather and a 5% under forecast of load growth. To build the loads for this year, the 8760 hour loadshape from the source weather year was multiplied by the economic forecast error multiplier. The resulting 8760 hour loadshape represents what the hourly loads would be expected to be in 2016 if the system experienced the same temperatures as 1980 and loads grew 5% faster than expected due to economic growth. This discrete scenario was simulated for 400 iterations. Each iteration runs for all 8760 hours for a single projected year (2016) attempting to match load and resources at the lowest system cost. Several stochastic variables including unit performance and dispatch error are used and result in independent costs and metrics for each iteration. The average of all the system costs and physical reliability metrics from all these iterations represent the expected values for this scenario.

In all, this process is repeated 192 times. Thirty two weather years combined with 6 economic forecast error points create 192 discrete scenarios. Simulating these scenarios for 400 iterations results in a full distribution of possible outcomes for the year 2016. It should also be noted that this process is applied to all regions in the study. When a 1980 weather year is being simulated, it is used for all regions. This modeling ensures that the actual differences in weather for each respective hour across the study system are captured. For example, when simulating July 9th, 1980, the loads for every region were developed using temperatures from July 9th, 1980. As the sensitivities demonstrate, the ability for one balancing area to provide assistance to another is critical, and understanding load diversity is a necessary component to that ability.

For this particular case study, we focused on the PJM Rest of MAAC (PJM_ROM) NEEM region from the EIPC Study. Although in reality this region is a participant in a structured market, for purposes of the base case analysis, it is treated as a vertically integrated utility. The purpose for this assumption is to simplify the economic comparison. When treated as a single vertically integrated utility, most of the internal load is served by resources within the region at those units' production cost. Purchases from outside the region are also assessed at their production cost unless the region is in a scarcity situation. Capacity is self-owned or procured through bilateral transactions between the utility and generators. Modeling the base case this way allows costs for consumers to be easily calculated. The economic reserve margin is based on minimizing total system costs for consumers. The applicability of this analysis to structured markets is discussed in section D of this chapter.

For this study, we set planning reserve margins for all other regions to their defined EIPC Study targets. Next, simulations were run for the study region from 10% reserves to 20% reserves in 2% intervals. To achieve the higher reserve margin levels, natural gas combustion turbine capacity was added. At each reserve margin level, LOLE, total system costs, and hourly market prices were tabulated. While the intent of economic reserve margin planning is to minimize total system costs to customers, the only difference between reserve margin levels is the addition of efficient CT capacity, so all base load costs can be ignored. Only costs that are above the dispatch costs of the marginal CT are tracked which represent the difference in total system costs. These system costs are made up of the following components:

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[48] SERVM is an economic resource adequacy model that is used by utilities to develop optimal reserve margin targets using economics as well as LOLE.

1. Production Costs above the dispatch cost of a CT (i.e. the dispatch of oil resources)

2. Net Purchases above the dispatch cost of a CT. Anytime the studied region purchased or sold at costs higher than the marginal cost of a CT, the net purchase costs were tabulated.

3. Unserved Energy Costs (MWh of unserved energy * VOLL) For the base case, the VOLL of was assumed to be $15,000/MWh. A sensitivity around this assumption is included in the sensitivity section.

4. Carrying Cost of additional CT Capacity. For the base case, $100/kW-yr was assumed. Results will be shown ranging from $80/kW-yr to $120/kW-yr.

For the case study, reserve margin was defined as the following:

Reserve Margin = (Total Capacity Resources – Expected Peak Load) / (Expected Peak Load)

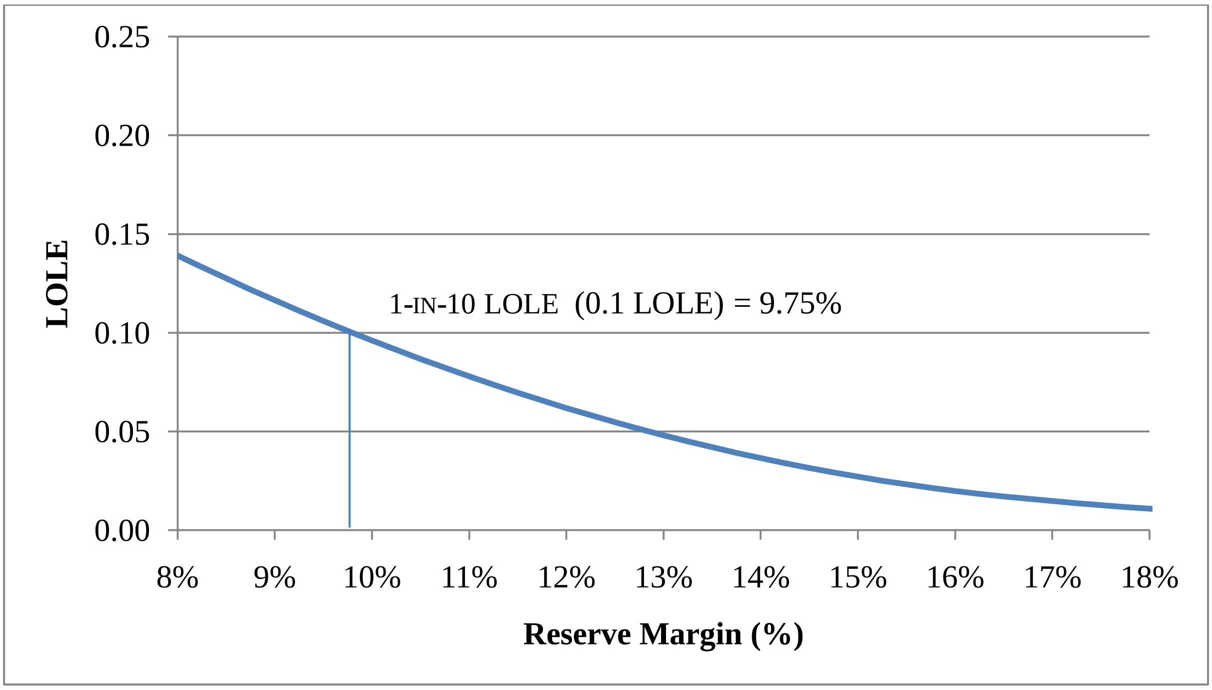
where total resources includes all demand response resource capacity and the effective load carrying capability of wind and solar resources. See the appendix for these effective load carrying capability values.

B. BASE CASE RESULTS ASSUMING A VERTICALLY INTEGRATED UTILITY

The following figures and sections discuss the Base Case Results.

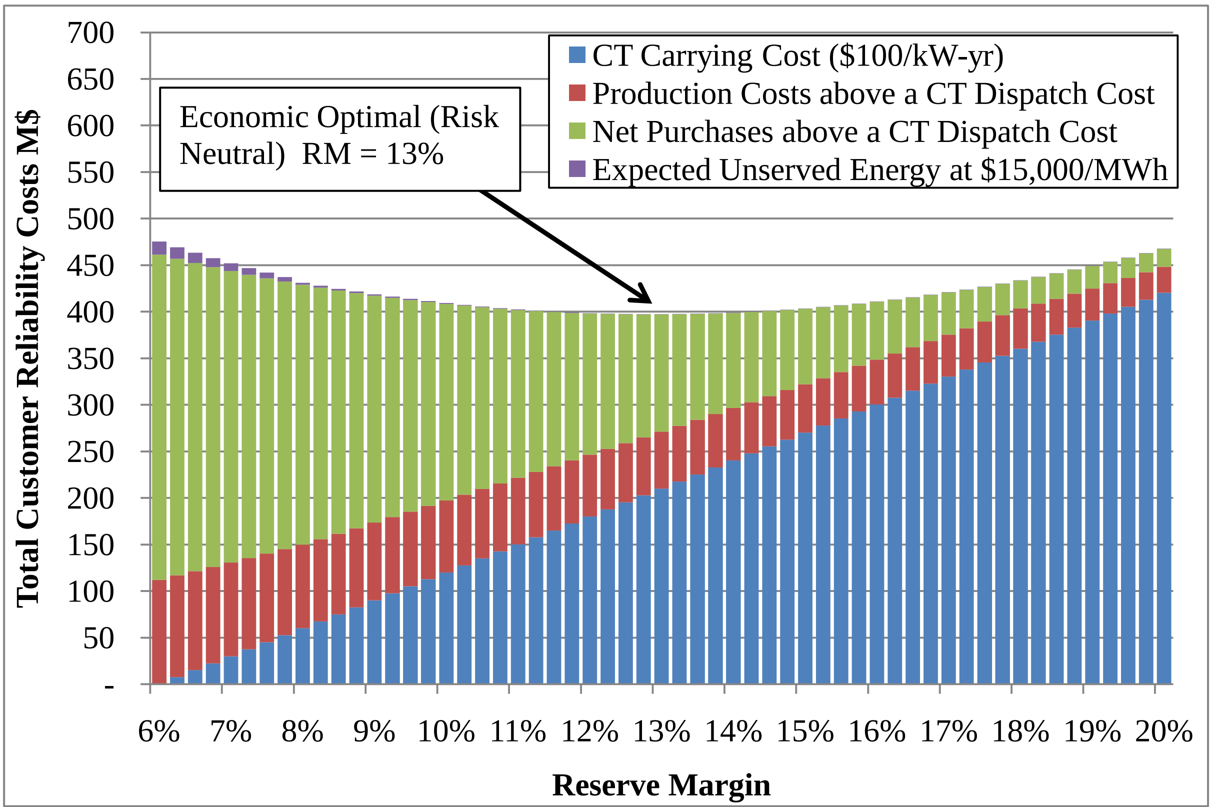
Figure 10 demonstrates that the reserve margin needed to meet the 1-in-10 LOLE standard (LOLE of 0.1) for the PJM_ROM region is 9.75%. An LOLH of 2.4 was met at below 8%. It should be noted that LOLE results are sensitive to input assumptions. As noted in the review of resource adequacy studies, PJM's own assessment indicates 1-in-10 LOLE for the entire PJM RTO falls at 15.3%. The two studies are not directly comparable since this analysis only considers one sub region of PJM and only generic unit outage data was used instead of utilizing actual historical generator availability data. However, one significant reason for this difference is that the PJM study assumes 3,500 MW of import capability, whereas the EIPC inputs assume 9,000 MW+ of import capability. Also, PJM derates 1,800 MW on peak due to temperature. The point here is not to challenge assumptions, but rather to demonstrate how large of a difference the selection of various inputs can change the results of the study. In addition to these, a number of other components that had the capability of shifting the 0.1 LOLE reserve margin by several percentage points were identified– at what point is demand response dispatched, will regions dispatch high cost or energy limited resources to support other regions, will a region shed firm load to maintain operating reserves, how much load diversity can be expected between regions, and will emergency hydro be available during peak load conditions. A few of these questions are addressed in the sensitivity section. While these assumptions can make a substantial difference in LOLE, they only affect a few hours per year or per decade, thus they typically don't have a meaningful impact on total costs or change the optimal economic reserve margin. Since the optimal economic reserve margin is affected by a much larger set of hours and events, it is typically less sensitive to minor inputs.

Figure 10. LOLE



The following figure, Figure 11, demonstrates the differences in system costs at a variety of reserve margin levels. The PJM ROM system represents ~30,000MW at peak load. A change of 1% reserve margin is approximately 300 MW. The carrying cost of this change is $30M/yr assuming the cost of capacity is $100/kW-yr. By adding this incremental capacity when the system is at a 10% reserve margin, total system energy costs (all production costs and purchase costs above the dispatch cost of a CT plus the cost of societal unserved energy) drop by $43M/yr and therefore justify the additional capacity. The additional capacity met a number of distinct needs. In some hours, the additional capacity was used to avoid high cost purchases. In other hours, the capacity avoided the dispatch of high cost resources such as oil turbines. During scarcity pricing conditions, the additional capacity may have avoided purchase costs and lowered market prices. A system that has 300 additional MW available will have lower scarcity prices than one which is 300 MW closer to not being able to serve firm load. And in extreme conditions, the additional capacity may have directly offset firm load shed. In looking at the graph, it is obvious that the benefit of reducing EUE is minor compared to the reduction in other costs as we have stated previously. The cost of EUE could vary greatly and have very little impact on the economics. Reliability at or near a 1-in-10 LOLE target already results in extremely low EUE.

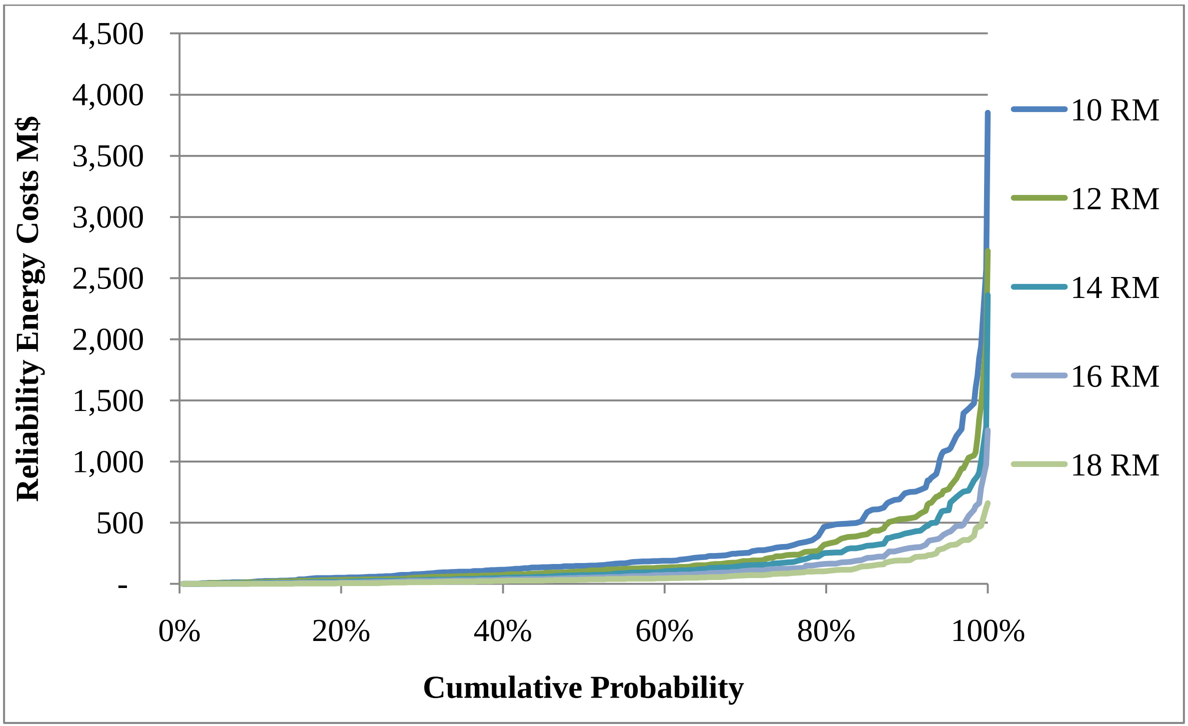
Figure 11. Economic Optimal (Risk Neutral) Reserve Margin[49]



Based on Figure 11, the minimum total system costs to customers is met at a reserve margin of 13%. The figure represents all system costs above the dispatch of a CT plus the cost of unserved energy plus the additional carrying cost of CT capacity over a range of reserve margins. It should be noted how flat the curve is between 12% and 15%. This says that there is some room to move within this range and not be penalized substantially by additional costs. Because this figure represents the average of 1000's of iterations (combinations of weather, load uncertainty, and unit performance), it hides the fact that individual years can be drastically different from the average. This economic target reserve margin doesn't put any additional emphasis on the extreme high cost outcomes, and is therefore defined as the risk neutral target reserve margin. When adding capacity in a regulated, vertically integrated market, the fixed costs are reasonably static whether procured through a PPA or through direct ownership by a utility. Based on detailed engineering estimates of the installed cost of CT capacity, resource planners can be fairly confident in the cost of capacity. In our example, 300 MW will cost approximately $30M per year. However, the incremental capacity may provide less than $1M in benefit in mild weather years during recessions or it may provide >$400M in value in years with extreme weather or unexpected load growth. Figure 12 shows the entire distribution of system energy costs (all production costs and purchase costs above the dispatch cost of a CT plus the cost of societal unserved energy) across different reserve margin levels. The high cost scenarios at the right hand of the chart represent the severe scenarios of extreme weather and under forecast of load.

[49] This figure represents customer system costs for a vertically integrated utility. Structured markets are discussed in later sections.

Figure 12. Distribution of System Energy Costs



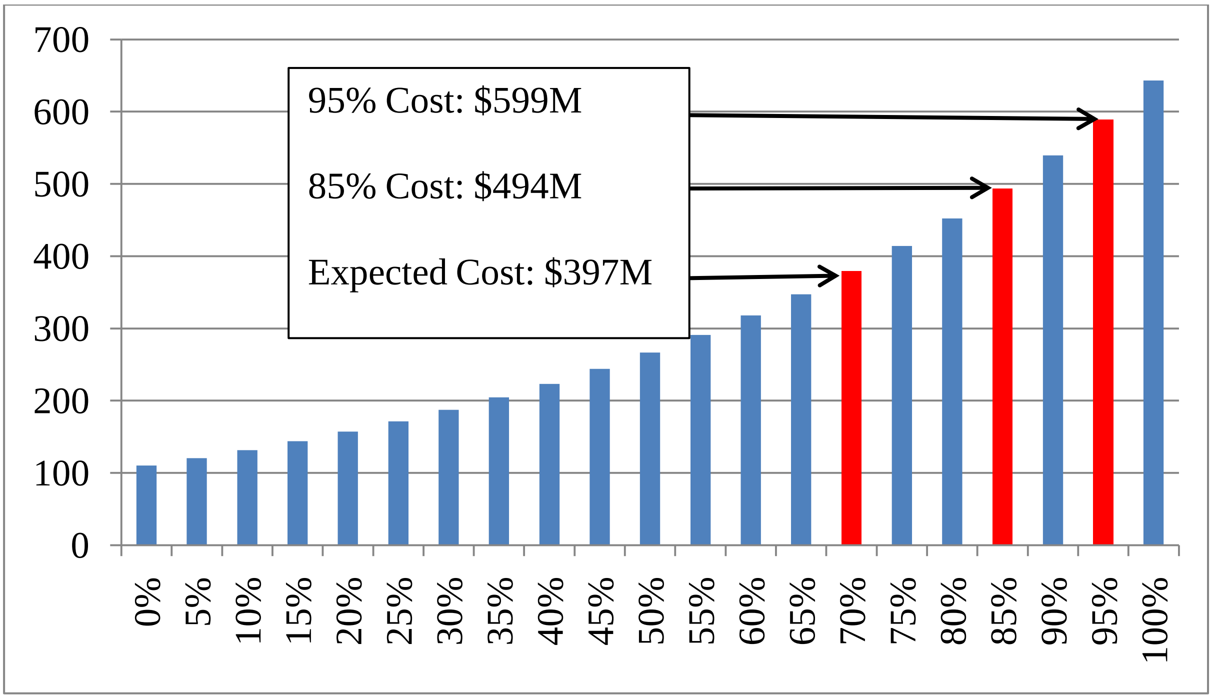
C. Risk Adjusted Reserve Margins

To make the trade-off between volatile reliability energy costs (production costs above CTs, purchases above CTs, and EUE costs) and static fixed costs (carrying cost of capacity), a risk adjustment is likely justified to the risk neutral optimum reserve margin. In the same way that a homeowner is willing to pay $1000/year to insure his $100,000 house against loss even though the probability of loss is far less than 1%, load serving entities are likely willing to pay a fixed payment toward installed capacity to insure against an extreme scenarios shown on the previous figure, even if the fixed payment is slightly higher than the average economic benefit. But how much more in fixed costs should customers, planners, and regulators be willing to pay above the amount that is justified by the risk neutral optimum reserve margin?

Traditional risk metrics in the electric power industry include Value at Risk (VaR), Coefficient of Variation, and mean-variance frontiers. Value at Risk is a quantitative measurement of the amount of exposure at various confidence levels within a specific time interval. Coefficient of Variation and Mean-Variance Frontiers are comparisons of variation across various portfolios and planners utilize them to minimize variance in an economically competitive portfolio.

While the conventional definition of VaR is the risk of loss on a specific portfolio of financial assets, it is used in this example as the risk of additional costs above expected costs. The distribution of total production costs above the dispatch cost of a CT plus marginal CT carrying costs for the 13% reserve margin case is shown in Figure 13. The expected cost for this case is $397M. Eighty-five percent of all scenarios in this case have total costs of $494M or less and 95% have total costs below $599M.

Figure 13. Distribution of Total Costs (Production Costs and Purchases Costs Above a CT + CT Carrying Costs + Cost of Unserved Energy) at 13% Reserve Margin



Typically firms will evaluate VaR at 85%, 90%, or 95%. The distributions for each reserve margin in the chart above allow us to calculate the approximate VaR over a 5-year period for the entire range of possible scenarios. Subtracting the total system cost from the average system cost produces the VaR at the respective confidence level. The VaR at 85% is $494M - $397M = $97M. This means that in 85% of all weather scenarios and economic growth scenarios, total costs should not be more than $97M above the expected costs. The table below, Table 6, summarizes VaR at a range of confidence levels for each of several different possible reserve margin targets including the 13% reserve margin example presented in Figure 13 above.

Table 6. Risk Analysis

		Risks Above Expected Costs		
Reserve Margin	Total Expected Costs	VaR 85	VaR 90	VaR 95
%	M$	M$	M$	M$
10%	409.3	145.3	208.4	321.2
11%	402.5	128.2	182.9	277.6
12%	398.5	112.2	159.2	237.8
13%	397.4	97.2	137.2	201.7
14%	399.0	83.3	117.0	169.3
15%	403.4	70.5	98.5	140.7
16%	410.7	58.7	81.8	115.8
17%	420.7	47.9	66.8	94.6
18%	433.5	38.3	53.5	77.1
19%	449.2	29.7	42.0	63.3

As an example from the previous table, moving from 13% reserve margin (economic risk neutral reserve margin) to a 15% reserve margin reduces Var 95 (a measure of the risk above the expected case) from $201.7M to $140.7M while the change in expected system costs from 13% to 15% is only a $6M increase (as seen previouslyin Figure 11). Targeting a 15% reserve margin results in slightly higher costs than the minimum cost reserve margin, but provides substantial risk mitigation from a single utility perspective. The determination of an economic optimal risk adjusted reserve margin which represents the ideal tradeoff in risk and cost will depend on the risk appetite of the decision makers at the respective utility or regulatory body.

D. Structured Markets: The Consumer Perspective

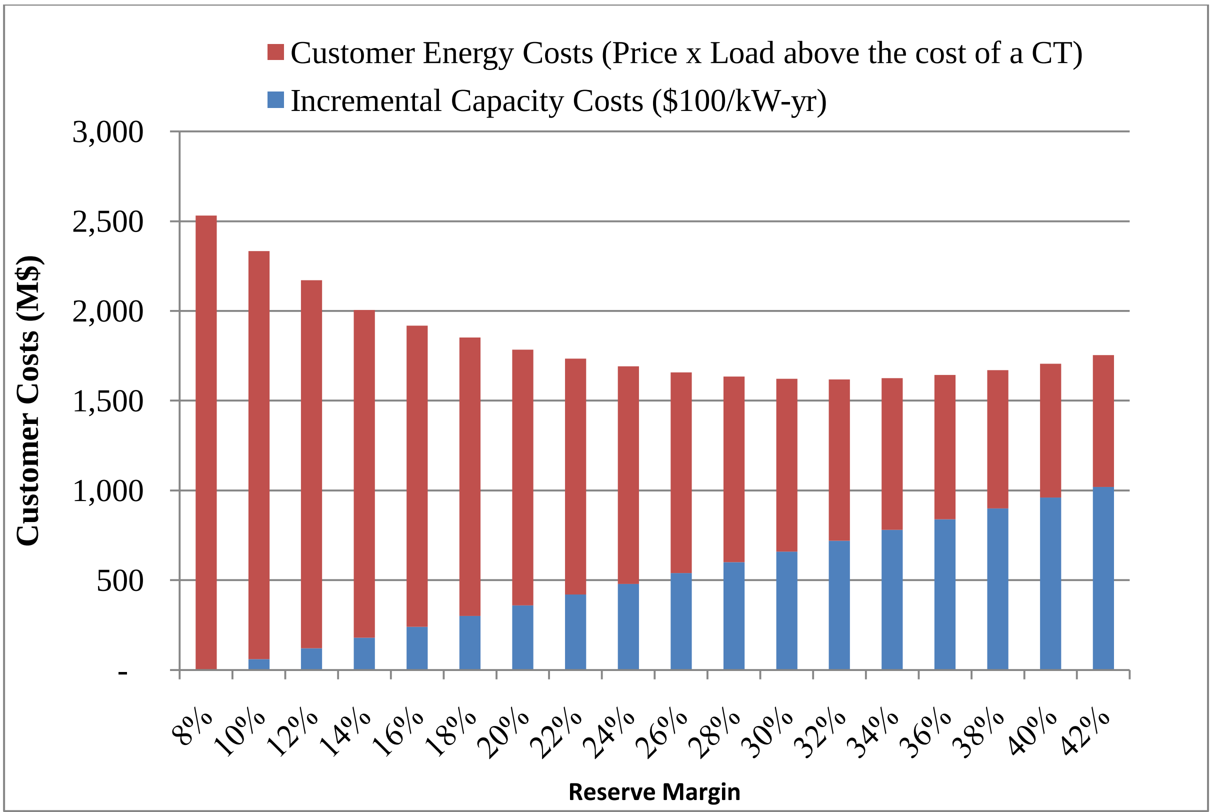
Economic reserve margin planning is contingent on market structure. In a vertically integrated utility environment with rate based assets, adding capacity only affects the cost of serving load that would have otherwise been met by resources with dispatch costs above the dispatch cost of that incremental resource. For example, imagine a utility which had no neighbors. The cost of serving load is only the physical production costs (fuel and variable O&M costs) of generating electricity to meet those loads. If this utility would typically dispatch oil turbines at loads above 30,000 MW at a cost of $300/MWh, the benefit of replacing the oil fleet with efficient gas turbines (with dispatch costs of $100/MWh) would only be the production cost savings ($200/MWh). In this example, if the oil fleet previously ran 100 hours per year, the benefit would only be \$20/kW-yr[50], not nearly enough to justify replacing the oil capacity.

However, under another market construct, the economic decision analysis would be very different. Imagine a wholly competitive energy market where all load serving entities are completely independent from generating companies. The load serving entity is forced to buy all its energy from the energy market at the market clearing price. Generators get paid based on which unit in the marketplace was on the margin, or which was the highest cost unit to be dispatched. For the owners of base load resources, having high cost oil generators on the system and in the dispatch for 100 hours per year could be a boon. Whenever a high cost unit is on the margin, each and every generator will be paid the dispatch cost of that unit, which in this example is \$300/MWh. If the system averaged 30,000 MW in load per hour, generators would receive \$900M[51] in aggregate over these hours. If the average production cost of those units was \$30/MWh, 90% of the revenue is operating profit. If the oil fleet was 1,000 MW in size, suppose replacing it with efficient gas turbines lowers the marginal cost in these hours to \$60/MWh. Now, the net revenue to all generators would only be \$180M[52] for these hours. The reduction in revenue of \$720M for generators is a direct benefit to consumers. In fact, since adding 1,000 MW of efficient CT lowered costs by \$720M per year, consumers would be getting \$720/kW-yr of benefit from capacity that should cost no more than \$100/kW-yr. However, base-load generators, that would no longer be receiving those revenues, may be dependent on this revenue to cover fixed costs. Any approach to identifying the ideal reserve margin target should consider both the generator and consumer's perspectives for the market structure being examined.

First, let us further consider the benefits of increased reserve margins to consumers in an energy only market structure. Using the same case study simulations, if we were to compare the energy market costs (assuming customers pay for their entire load at the market clearing prices) as seen below in Figure 14 to a proxy for incremental capacity costs, then the cost/benefit analysis could support reserve margins above 30% meaning there are still energy market savings greater than the incremental capacity costs at these reserve margin levels. The difference between this analysis and the results seen in the single regulated utility example previously shown in Figure 11 is due to the fact that load serving entities (customers) are paying the high spot prices for all load (30,000 MW) in a given hour versus only paying expensive prices for the high cost resources on the margin which may only be a couple hundred MWs of load.

[50] \$200/MWh * 100 hr/year = \$20/kW-yr
[51] \$30,000 MW * \$300/MWh * 100 hrs = \$900 M
[52] \$30,000 MW * \$60/MWh * 100 hrs = \$180 M

Figure 14. Illustration of Economic Target for a Load Serving Entity That Relies 100% on the Energy Market



This is a purely hypothetical exercise however. Setting a reserve margin target based on these customer savings is not feasible or desirable in current structured markets for several reasons. First of all, in energy only markets the incremental capacity costs shown in Figure 14 are not paid by consumers so the consumers would always benefit from higher reserve margins while energy margins for generators continually decrease. In structured markets that have forward capacity markets, all generators are paid the same capacity price. In the above example, only the incremental capacity costs were assumed to illustrate the comparison to the vertically integrated utility analysis in Figure 11. In addition, load serving entities in current RTOs often self supply or enter into bilateral agreements to cover a substantial portion of their load and balance the remainder of their load using the energy market. Under this scenario, the savings to customers would be greatly reduced and would more likely resemble the optimal reserve margin methodology that was shown previously in Figure 11. While the idea that a reserve margin well above 20% is ideal for consumers fully exposed to the energy market may be counterintuitive, it is simple to demonstrate. In PJM in 2010, reserve margins were well above 20%[53], but there were still 81 hours with energy prices more than $100/MWh higher than the dispatch cost of a CT. The load in these hours for the PJM_ROM region averaged 33,000 MW, so the total cost of energy above the cost of CTs was greater than $264M[54]. If an additional 1,100 MW of combustion turbines had been present,

[53] *2011 Long-Term Reliability Assessment*, retrieved on September 2, 2012 from http://www.nerc.com/files/2011LTRA_Final.pdfNERC LTRA

[54] 33,000 MW * 80 hours * $100/MWh = $264 M

presumably the costs above CTs would have been negligible[55]. This suggests that 1,100 MW of CTs can save $264M in one year compared to the carrying cost of that capacity at only $110M[56] per year. This lends some credence to our theory that consumers exposed to the energy markets can receive substantial benefits with new resources even at high reserves margins.

In the same region, however, energy margins for CTs were only ~$50/kW-yr. So CTs were not getting full cost recovery from the energy market, and yet consumers would have benefitted from substantially more capacity.

E. STRUCTURED MARKETS: THE GENERATOR PERSPECTIVE AND THE MISSING MONEY PROBLEM

Wholesale peaking generators have not been able to recover their fixed carrying costs in the past decade from energy markets. Even in regions with capacity markets which pay supplemental revenues to generators, without long-term bilateral agreements, CTs have been unable to cover costs[57].

But how critical of an issue is this? Economic optimal reserve margins for energy only markets are defined as the point at which marginal capacity can earn enough revenues to cover fixed costs. How far from this economic target are most structured markets today? CT energy margins are the summation of all the hourly market prices above the dispatch cost of a CT for a given year. As shown in Table 7, which presents the perspective of a merchant generator in such a market, CT energy margins and the frequency of prices above the dispatch cost of an efficient CT decrease as additional CTs are added to a system. These energy margins represent the weighted average energy margins in the Base Case simulations. Recall that the 1-in-10 LOLE based reserve margin was at 9.75% and the economic optimal reserve margin based on a single regulated utility was 13% (See Figure 11). The CT only receives $86/kW-yr at a 9.75% reserve margin and $73/kW-yr at a 13% reserve margin which is used to go towards covering its fixed costs of $100/kW-yr. The energy only economic optimal target reserve margin for this region is 7% because that is the point where a CT fully recovers its fixed costs.

Table 7. Merchant Generator Perspective

Reserve Margin	8%	10%	12%	14%	16%	18%
Expected CT Energy Margins ($/kW-yr)	$ 94.75	$ 85.63	$ 77.58	$ 70.57	$ 64.62	$ 59.72
CT Hours of Operation	1,211	1,104	1,007	978	926	897

How is it possible then that generators are only able to recover their fixed costs at a 7% reserve margin, but consumers of a vertically integrated utility have financial benefit to having reserve margins at 13%? In many hours in the simulations, the study region is

[55] Load in these hours was 1,100 MW higher than in hours with prices equal to the dispatch cost of a CT, suggesting the addition of 1,100 MW of efficient CTs would bring the high prices down close to the cost of a CT.

[56] 1,100 MW * $100/kW-yr = $110 M

[57] PJM, State of Market Report, 2010, Vol. 2, p. 33

purchasing power from outside regions. Take an example hour in which the region is purchasing 2,000 MW at $200/MWh. The addition of 500 MW of resources to the study region does more than just avoid purchase costs of 500 MW at $200/MWh. It actually brings down the cost of the remaining 1,500 MW that needed to be purchased. When the study region was originally purchasing power from the outside region, the clearing price was based on the unit that was on the margin in the outside region. In order for the study region to buy 2,000 MW, the outside region had to dispatch progressively higher cost resources. Since in the change case in which the study region added 500 MW of capacity, only 1500 MW needed to be purchased, the clearing price for the purchase will be lower (for this example assume purchase cost dropped to $150/MWh). So the addition of the resource provided $140/MWh of benefits for the 500 MWh of purchases it avoided[58]. It also achieved $50/MWh benefit for the 1,500MWh of purchases that were still made. The total benefit in this hour is $145,000[59] or $290 for each MWh of energy provided by the new resource[60]. So the benefit to the customer is higher than the revenues that might be seen by the new generator. This disconnect between the consumer perspective and the generator perspective was partially explained above, but there are additional reasons that generators have a difficult time recovering costs in many structured markets today.

1. Price Caps

Many regions have regulatory caps on bid prices at ranges between $1,000/MWh to $3,000/MWh. As discussed, this is less than VOLL and from a theoretical perspective suggests that consumers are not paying enough for resource adequacy. However, there is a reserve margin at which peaking generators would cover the cost regardless of where the price cap was set. If generators could achieve full cost recovery at an 11% reserve margin with no price caps, then generators should be able to achieve full cost recovery at perhaps an 8% reserve margin if there was a $1,000/MWh price cap. The point being that if the maximum price is lower than VOLL, generators should build less capacity such that high prices (but less than $1,000/MWh) are hit more frequently. Price caps are frequently cited as the primary reason for "missing money"[61], yet the authors believe this is a small component of the overall market design problems.

2. Physical Reliability Targets

ERCOT is one of few energy-only markets in North America. As an energy only market, there is no explicit reserve margin target. However, ERCOT performs an LOLE study periodically which communicates to the system the reserve margin which would achieve 0.1 LOLE. While not a target, several of the LSEs in ERCOT may use that reserve margin for their own generation planning and either build or contract to maintain at least that level of reserves. The potential result of individual LSEs planning to the 0.1 LOLE reserve margin is that the aggregate system reserve margin may be equal to or higher than the 0.1 LOLE reserve margin. If a region consisted of 10 LSEs, all of which planned to the same reserve margin independently, the aggregate reserve margin would be higher since there is diversity between disparate loads. But regardless of how a region

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[58] The load serving entity paid the $60/MWh dispatch price of the resource instead of the $200/MWh market price

[59] (140 * 500 + 50 * 1,500) = $145,000

[60] $145,000 / 500 MWh = $290/MWh

[61] Hogan, William (2005), "On an "Energy Only" Electricity Market Design for Resource Adequacy."

ends up with a reserve margin that is equal to or higher than the 0.1 LOLE, the impact on CT energy margins is typically negative. As shown in our simulations, the expected CT energy margin at a 0.1 LOLE reserve margin is less than the carrying cost of capacity even with no energy price caps. To clarify the theoretical reason for this disparity, an illustration will be helpful.

Imagine that regions planned to a reliability target of one event in 10,000 years. To achieve this lofty goal, reserve margins may need to be at 30%. With a 30% reserve margin, there would be very few, if any, hours with energy costs much above the dispatch cost of CTs. Unlimited price caps would make no difference since there would almost always be additional capacity available to prevent scarcity prices. So if load serving entities or a portion of the load serving entities in a region plan to an LOLE target, it is possible that system reserve margins may be higher than the levels at which generators would receive cost recovery.

3. Economic Growth Slowdown

Since 2000, the US economy has consistently grown at slower rates each year than was expected 4 years prior.[62] When the economy grows slower than expected, load grows slower than expected. Since generation expansion is planned years in advance, new generation has come online while the load it was meant to serve has not materialized. An example utility may have expected 1,000 MW of load to appear due to a growing economy and so built new generation. However, much of that load did not appear over the past 10 years and so reserve margins rose. With reserve margins not only above the level which would achieve cost recovery for efficient CTs, but also above 0.1 LOLE based reserve margins which typically result in low CT energy margins, returns for peaking generation have been consistently small. Presumably, at some point the economy will begin to grow faster than economists expect and load growth may outstrip resource additions, resulting in lower reserve margins and higher returns for peaking generators. However, as discussed in other sections, reserves would need to drop substantially in order for this to occur.

To be clear, this issue is different from the issue related to the use of physical reliability metrics in setting reserve margin targets. Even if the economy was experiencing robust growth, the use of physical reliability metrics could still negatively affect the energy revenues generators could expect. Slow economic growth simply adds to the disparity produced by high reserve margin targets since realized reserve margins end up being even higher than the high reserve margin targets when the economy grows slowly.

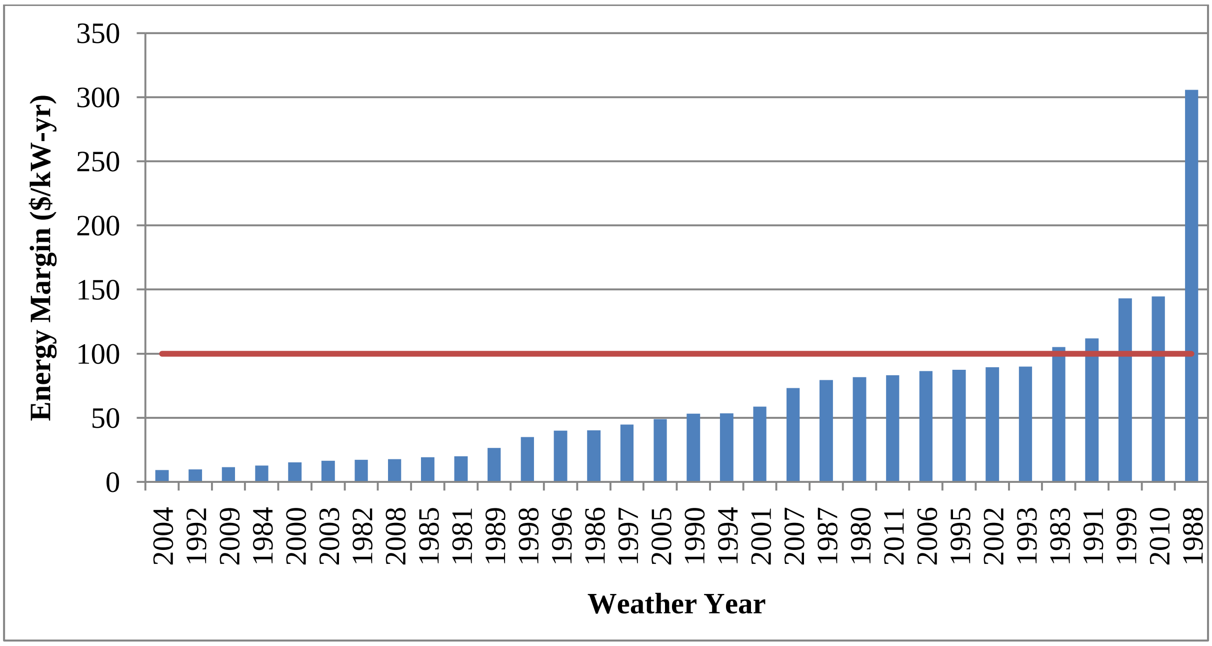
4. Weather Volatility

Even with a regulatory-enforced scarcity pricing curve designed to achieve full cost recovery for peaking generators, differences in weather patterns mean that many years energy prices would be lower than needed for generators to recover costs. Figure 15 shows results from the Base Case simulations for the study region. In a small number of possible weather years, returns would far exceed the necessary levels to cover carrying costs. However, in a large percentage of years, revenues would be far less than necessary. This is not a feasible market space for many developers who rely on debt to

[62] See CBO forecast for 2000-2013

finance the construction of their facilities. If a generator cannot demonstrate its ability to cover specific debt service ratios each year, it will not be eligible for debt financing.

Figure 15. CT Energy Margins by Weather Year



5. Generator Market Forecasting

The authors will not venture to guess the skill level of generators determining when markets will be in equilibrium such that new generation can cover fixed costs. However, this task is quite difficult, so expectations of their accuracy should be quite low. This analysis must typically be performed 5 years in advance of the new generation coming online and take into account dozens of variables including load growth rates, fuel costs, market interaction, regulatory intervention, scarcity pricing, emission prices, resource mix changes, demand response impacts, and bidding strategies.

In summary, each of the components mentioned above contribute to the missing money problem. It is not an isolated issue simply due to a single design flaw as frequently cited. Since generators in energy only markets prefer low reserve margins to achieve cost recovery what is the best way to incentivize generator investment to achieve 1-in-10 LOLE and/or achieve a higher reserve margin that is more economic for consumers. Forward capacity markets have been designed in many of the existing structured markets to alleviate this disconnect. In this capacity market design, all generators are provided additional capacity payments to allow new generators to recover fixed costs at a reserve margin that meets 1-in-10 LOLE standard. The setback to this approach is that while consumer energy costs are reduced at the 1-in-10 LOLE level, the fact that capacity payments are paid to all capacity forces total customer costs to be higher than if reserve margins remained at the lower energy only economic reserve margin target. This is further illustrated in the next section. Another method used to solve this problem is to force load serving entities to enter into bilateral contracts up to a specified reserve margin. This method is used in the California ISO (CAISO) today. One advantage of this method is that it allows generators to enter into long term contracts which provide revenue stability versus a forward capacity market which only provides revenue in the short term. It also allows load serving entities to make decisions on capacity based on long term cost projections.

F. SUMMARY RESULTS FOR DIFFERENT MARKET CONSTRUCTS

Table 8 summarizes the findings of the base case results from the perspective of a single vertically integrated regulated utility, energy only market, and energy plus forward capacity market. Table 8 shows that the economic optimal reserve margin for the regulated utility is 13% based on the consumer's total system cost perspective as defined in Section A of this Chapter . This target resides several percentage points above the 1-in-10 LOLE based 9.75% reserve margin. The reserve margin target for the energy only market is 7% based on the level of reserves at which a new CT will recover its costs. Under an energy only construct, consumers would benefit from higher reserve margins but energy margins are lower than the minimum required to sustain the higher reserve margin. For the energy plus forward capacity market construct, the target reserve margin is assumed to be based on 1-in-10 LOLE[63] which is 9.75% and it is assumed that the capacity payment paid to all generators at this level is enough that when combined with energy margins a CT will recover its fixed costs.

From a total system costs perspective, the regulated utility provides the lowest cost at its target reserve margin. It should be noted that the results for each construct were developed from the same simulations meaning there were no benefits recognized from a more coordinated economic dispatch that an RTO/ISO would provide. The energy only construct's total costs at a 13% reserve margin are much lower per year, but in theory this reserve margin would not materialize because generators would not recover their fixed costs at this level. The energy plus capacity market construct produces higher costs as reserve margins increase from the 7% energy only economic target because the additional capacity payments are made to all generators. If targeting 1-in-10 LOLE, the total costs including a capacity payment that made generators whole is $7.925 B as shown in the table. It should be noted that there is also some risk benefit seen with the structures that result in higher reserve margin targets because the volatility related to energy costs decreases as reserve margins increase.

Assuming idealized resource mixes and purely competitive or efficiently regulated markets, the cost comparison below illustrates how the structure that results in the lowest reserve margin does not necessarily produce the lowest system cost.[64]

Table 8. Total System Costs at Target Reserve Margin Levels

	Target Reserve Margin	Total System Costs at Target (Billion $)
Regulated Utility	13.00%	$7.805
Energy Only Market	7.00%	$7.860
Energy plus Capacity Market	9.75%	$7.925

To be clear, the point of this table is not to state that the regulated utility environment is the optimal structure. Energy only and energy plus capacity markets offer a number of attributes such as fostering competition and diverse resources that may result in lower total system costs for customers. This table just highlights that market structure can have a

[63] Forward capacity markets in the Eastern Interconnection currently base targets on 1-in-10 reliability metrics. These include PJM, NY-ISO, and ISO-NE.

[64] These total system costs include all capacity costs and energy costs (not just costs above the dispatch costs of a CT) to meet load as well as the societal costs of unserved energy.

significant impact on both reliability and total system costs and should be considered when performing resource adequacy planning.

G. Selection of Marginal Resource in Economic Reserve Planning

It is important to remember that the identification of a target reserve margin based on economics is contingent on the marginal resource used to vary reserve margins. A single point estimate of the ideal reserve margin assumes that all capacity should be treated as equal. In reality, economic resource adequacy planning must consider the implications for all types of resources that may provide resource adequacy. The economic trade-off analysis is highly dependent on the characteristics of the capacity being added. All capacity is not equal. Adding demand response capacity will not provide as much economic benefit since it is not dispatched until prices are much higher or reliability is a more pressing concern. In generic SERVM modeling runs, the average market price when CTs are dispatched is ~$70/MWh. The average market price when demand response is called may be $500/MWH+. This indicates that the system costs between reserve margins will be drastically different if CTs are the marginal unit type vs. demand responses resources. The carrying costs are also different between the resource types. Also, the incremental decision may not be the addition of a new resource; it may be the retirement of an old high-cost resource. While 1-in-10 LOLE is an attractive metric because of its simplicity, the reserve margin determined through this method treats all capacity the same. If a resource can keep the lights on as effectively as a combustion turbine, the different product characteristics are immaterial. But the metric doesn't provide guidance to what type of resources should be used to meet peak requirements and leads to many uneconomic resource procurements. Resource planning is unfortunately a complicated process that requires the assessment of both the economic and physical reliability contributions of resources.

VI. IMPACT OF VARYING DEFINITIONS, CALCULATIONS, AND APPLICATIONS OF 1 IN 10 ON ECONOMICS

Based on the research performed in Section III, the majority of entities in the Eastern Interconnection that use a physical metric for setting reserve margin targets use the 1 day in 10 year standard. Of those that use the 1 day in 10 year standard, all but one use an identical definition for the metric. SPP is the only entity that uses a different definition. SPP assumes 2.4 LOLH versus the standard 1 event in 10 years (0.1 LOLE). The latter is more stringent and leads to a higher reserve margin level. In this study, using the 2.4 LOLH definition typically results in a reserve margin 5% lower than the 0.1 LOLE derived reserve margin. However, although SPP measures reliability against the less stringent 2.4 LOLH metric, their reserve margin target is set at a higher level than suggested by the metric, potentially obviating the difference in expected reliability.

As part of this paper, the authors were asked to address how the varying definitions, calculations, and applications of the 1 day in 10 years standard impact the economics of resource adequacy. If regions planned reliability using the lower 2.4 LOLH instead of the 0.1 LOLE, reliability costs would be much higher. The base case simulations indicate reliability costs (excluding capacity costs) at the 0.1 LOLE equal to $290M/yr while the reliability costs at 2.4 LOLH are $450M/yr, a difference of $160M/yr. The 2.4 LOLH scenario has lower capital costs since it has a lower reserve margin, but even after adjusting for capital cost savings, the less stringent 2.4 LOLH developed reserve margin would result in additional total system costs of $40M/yr compared to planning using the 0.1 LOLE definition. In addition, those numbers do not reflect what would happen if all regions used the lower standard. The base case assumes that other regions still maintain higher reserves, muting the impact of the less stringent standard. If all regions planned using the lower standard, average costs would be expected to be exorbitant. In addition, average economics doesn't adequately consider the risk of high impact scenarios. In cases in which load was much higher than expected or units didn't perform as well as expected, the additional costs of only maintaining reserves to meet the 2.4 LOLH on average could be in the billions of dollars. The base case economic simulations indicated that the difference in costs for the most extreme case if planning to 0.1 LOLE versus planning to 2.4 LOLH could be greater than $2B for a single year.

For a small region with few interconnections, the 0.1 LOLE and the 2.4 LOLH based reserve margins could potentially both be higher than the optimal economic reserve margin, but in general, the base case simulations demonstrate that using the 2.4 LOLH definition likely results in a more risky and high cost system if modeled accurately. Compared to the 0.1 LOLE, the economic optimum reserve margin could be higher or lower depending on a number of system attributes including system size, market structure, neighbor assistance availability, and transmission availability. And depending on assumptions such as how emergency operating procedures will be employed and how capacity is counted, the comparison is further complicated.

The sensitivities presented in the next section show how some of these assumptions drive the 1-in-10 LOLE target and the economics of resource adequacy. Based on our past experience, the 1-in-10 LOLE target is more sensitive to these assumptions than a methodology that uses an economic framework. An LOLE method can be driven by one event or one peak hour while the economics that measure more than the cost of firm load shed are impacted by many more hours across the year and are therefore less sensitive. From our perspective, it is critical for regulators and planners to know if its target reserve margin is economic.

VII. IMPACT OF INTERCONNECTED MARKETS AND BROAD PLANNING ON RESOURCE ADEQUACY AND 1 IN 10 CALCULATIONS

Astrape performed several sensitivities around the regulated utility base case to show the impact that interconnected markets and inter-regional commerce have on the resource adequacy of the region being studied. If markets are highly interconnected and well coordinated among regions, then resource adequacy targets could be lowered. In the base case, there is substantial transmission capability between the study region (PJM_ROM) and surrounding neighbors. In fact, the limit to and from PJM_E and PJM_R_RTO is virtually unlimited as the 8,000 MW transfer capability is rarely fully utilized. With these limits, it is likely that the constraint is capacity on the other side of the interface rather than the transmission capability.

A. ISLAND SENSITIVITY

The first sensitivity that was simulated treated PJM_ROM as an island. This sensitivity is purely academic since it in no way represents reality. When the case is simulated, the region would need to carry an 18% reserve margin to meet the 1-in-10 LOLE standard. This compares to a 9.75% reserve margin to meet the same criteria in the base case. Given these results, it could be stated that surrounding regions via load diversity and generator diversity provide approximately 8% of reserves for the PJM_ROM region. For this sensitivity, economics were not evaluated.

B. ALLOW NEIGHBORING REGIONS TO DISPATCH DEMAND RESPONSE IN ORDER TO ASSIST NEIGHBORING REGIONS

The next sensitivity was designed to understand the impact of allowing regions to dispatch demand response resources in order to assist another region. The typical approach to demand response is to only call on it during emergency conditions. In actual practice, it is unlikely that one region would dispatch emergency demand resources in order to be able to sell generation to other regions. However, there is a range of types of demand response, some of which may self-dispatch at lower prices or may have substantial availability. These resources may be dispatched more frequently and may possibly be used in a way that allows one region to sell to other regions. The base case did not allow these resources to be called in order to free up other capacity to be sold to neighbors. The change case was to eliminate this constraint. If one region was able to meet firm load obligations and operating reserve requirements in an hour, and had additional demand response capacity, SERVM was configured to allow the demand response resource to dispatch and sell energy to another region. In this change case, the reserve margin needed to maintain 0.1 LOLE shifted from 9.75% to less than 7%. The economic optimum shifted from 13% to approximately 12%. This change in emergency dispatch affects the 0.1 LOLE based reserve margin more than the economic reserve margin because LOLE is more sensitive to what occurs in these peak hours.

C. OPERATING RESERVE SENSITIVITY

For the base case simulations, all regions were given a 2% spinning reserve requirement and a 4% total operating reserve requirement. Firm load shed occurred if operating reserves dropped below the 2% spinning reserve requirement. In this sensitivity, the spinning reserve requirement was allowed to be completely depleted before shedding firm load. As expected, the results of the sensitivity showed that both the 1-in-10 LOLE target and economic target dropped by 2%.

D. System Equivalent Forced Outage Rate (EFOR) Sensitivity

The Equivalent Forced Outage Rate (EFOR) is the average percentage of capacity unavailable when needed. The 1-in-10 LOLE target and the economic optimal target both shifted with a 1 to 1 ratio as system EFOR shifted. In other words, when system EFOR for the region was increased by 3%[65], the 1-in-10 LOLE target shifted from 9.75% to 12.75% and the economic target shifted from 13% to 16%.

E. Remove all Load Diversity Among Neighbors

If load diversity is removed completely and all regions reached peak load at the same time, then the target to meet a 1-in-10 LOLE standard shifts from 9.75% to 15.5%. The economic target shifts from 13% to 18%. The impact during peak hours impacts LOLE slightly more than it impacts the economic target.

F. Transmission Sensitivities

Two sensitivities were performed for transmission. In the first, all transfer capabilities between regions were reduced by 50%. In the second a distribution was used for each interface representing the availability of the interface. The distribution for this sensitivity is shown in Figure 16. By using this distribution, the range of transmission availability can be captured from 0% to 100%.

Figure 16. Distribution of Transmission Availability

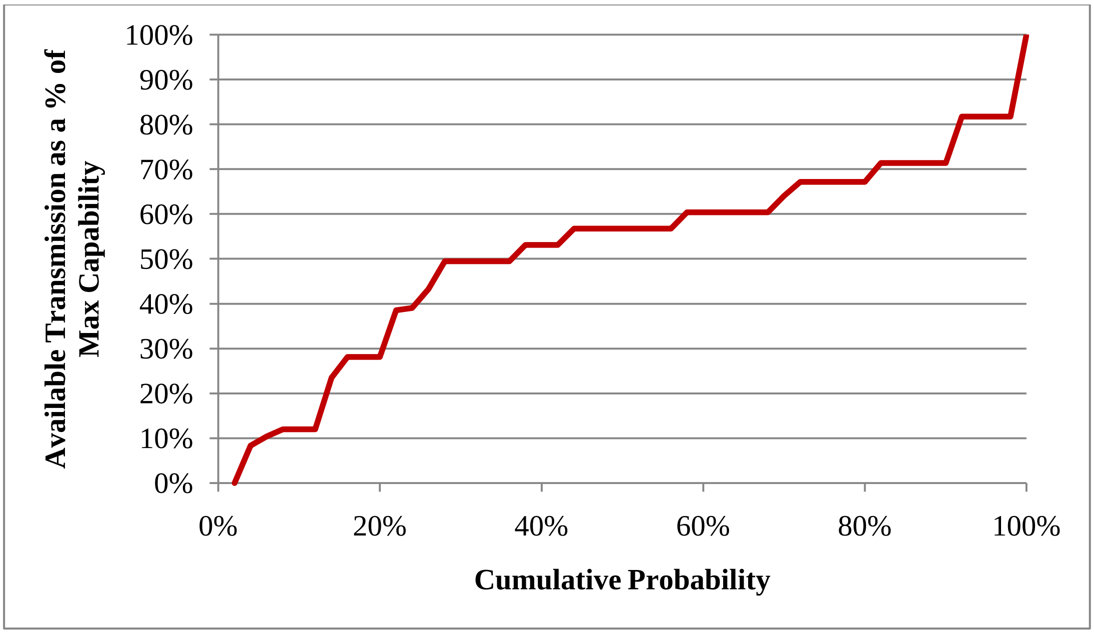


Table 9 shows the results of the two sensitivities. Using the distribution shown above in Figure 16 impacts both the 1-in-10 LOLE and economic optimal reserve margin more than just reducing the capability by 50%. This is logical because the distribution is more stringent in that there are hours where no transfers will be allowed to occur. Because the region being studied has substantial oil resources in its mix, it is purchasing a substantial amount of energy for economic reasons. When transmission is limited, these purchases decrease and the

65 The starting system EFOR of 5% was increased to 8%.

optimal reserve margin level increases considerably. Accurately capturing the import capability of a region has a high significant impact on results.

Table 9. Transmission Sensitivities

	Reserve Margin @ 1-in-10 LOLE Standard	Economic Optimal Reserve Margin	Avg. Demand Response Call Hours Per Year at 10% RM
Base Case	9.75%	13.00%	4.5
50% Transmission Capability	11.75%	17.00%	15
Transmission Distribution	14.00%	20.00%	13

Since the base case uses static high transfer limits, the base case results are likely too optimistic for both the economic optimal reserve margin and the 1-in-10 LOLE reserve margin. Using refined transfer limits would likely show that for the targeted region, the optimum economic and 1-in-10 LOLE reserve margins would be several percentage points higher. The table above indicates a reasonable upper limit for where these values could fall.

G. Expanding Topology

A sensitivity was performed to understand how expanding the overall topology would impact the optimal reserve margin for PJM_ROM. For the sensitivity, SOCO and NE-ISO were added to the topology. By adding two additional regions, the LOLE target shifted from 9.75% to 9.25% and the economic target shifted from 13% to 12.5%. Even though PJM-ROM is not directly connected to either region, the dynamic market clearing resulted in more efficient dispatch and the additional regions provide extra load and generator diversity. This indicates that modeling the entire Eastern Interconnection could result in lower targets than indicated by the base case results.

H. Summary

A summary of these results for both the base case and numerous sensitivity cases is shown in Table 10. The overall takeaway is that an optimal level of reserves depends greatly on assumptions made about surrounding interconnections and installed capacity of neighboring regions. These sensitivities also illustrate the need for further analysis in which the full Eastern Interconnection is simulated and appropriate assumptions are verified for a number of these categories.

Table 10. Summary of Analysis Results for Base and Sensitivity Cases

	Reserve Margin @ 1-in-10 LOLE Standard	Economic Optimal Reserve Margin	Avg. Demand Response Call Hours Per Year at 10% RM
Base Case	9.75%	13.00%	4.5
Island Case: No Neighbor Assistance	18.00%		21.5
No Weather Diversity Among Neighbors	15.50%	18.00%	9.4
50% Transmission Capability	11.75%	17.00%	15
Transmission Distribution	14.00%	20.00%	13
All Regions Allowed to Share DR Resources	7.00%	12.00%	5
Allowing All Operating Reserves to be Depleted	7.75%	11.00%	4.5
EFOR 3% Increase	12.75%	16.00%	5.9
Expand Topology	9.25%	12.50%	4.25

VIII. ECONOMIC SENSITIVITIES

Sensitivities were performed both on the VOLL and the cost of CT capacity additions. Changing VOLL from $5,000/MWh to $30,000/MWh had no impact on the economic optimal reserve margin. The reason is that the amount of EUE at 13% reserve margin is only ~20MWh and represents reliability above the 1-in-10 LOLE standard. Firm load shed events are not driving the economics to be minimized at a 13% reserve margin. An additional sensitivity analyses varied the cost of CT capacity from $80/kW-yr to $120/kW-yr. Table 11 below shows that the economic optimum is more sensitive to capital costs.

Table 11. Economic Sensitivities

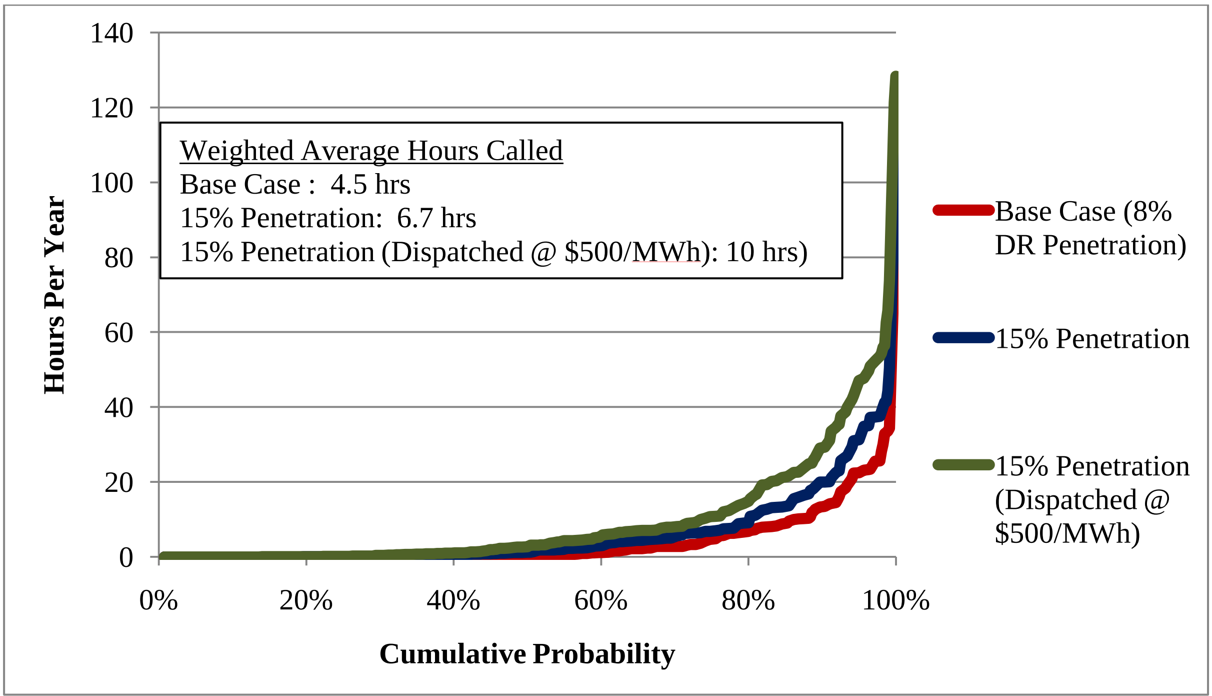
	Economic Optimal Reserve Margin
Base Case: VOLL@15,000/MWh CT Carrying Costs @ $100/kW-yr	13.00%
VOLL @ $5,000/MWh	13.00%
VOLL @ $30,000/MWh	13.00%
CT Carrying Costs @$80/kW-yr	15.25%
CT Carrying Costs @$120/kW-yr	10.25%

IX. RESOURCE MIX SENSITIVITIES AND HOW STATES CAN POSITIVELY INFLUENCE RESOURCE ADEQUACY

A. DEMAND RESPONSE SENSITIVITIES

Demand Response plays a key role in resource adequacy assessments. The key attributes of DR that impacted simulation results are the number of hours the resource can realistically be called in a given year, the point in the dispatch that DR is called, and the percentage of total capacity represented by DR (this percentage is also referred to as the penetration). If DR is called by a utility when prices hit $200/MWh versus $500/MWh, then the resource will provide much more economic value but will obviously need to be available more hours in the year. Figure 17 shows the distribution of expected demand response calls for the base case and two sensitivities with different penetration levels. Recall that the base case assumptions assume that DR is only called after all other options have been exhausted including expensive purchases up to $2,500/MWh and are limited to 150 hours per year. So in the base case, DR is exclusively used for reliability purposes and is always available since its dispatch is so infrequent. Also in the base case, DR provides 8% of the overall capacity mix for the region. The other two curves represent the senstivitiy cases where (1) DR penetration is 15% and resources are called at $2,500/MWh (2) DR penetration is 15% plus resources are called at $500/MWh. Additional sensitivities assuming the resources are called at $200/MWh would show increased frequency of dispatch and the necessary call limits would expand.

Figure 17. DR Call Summary



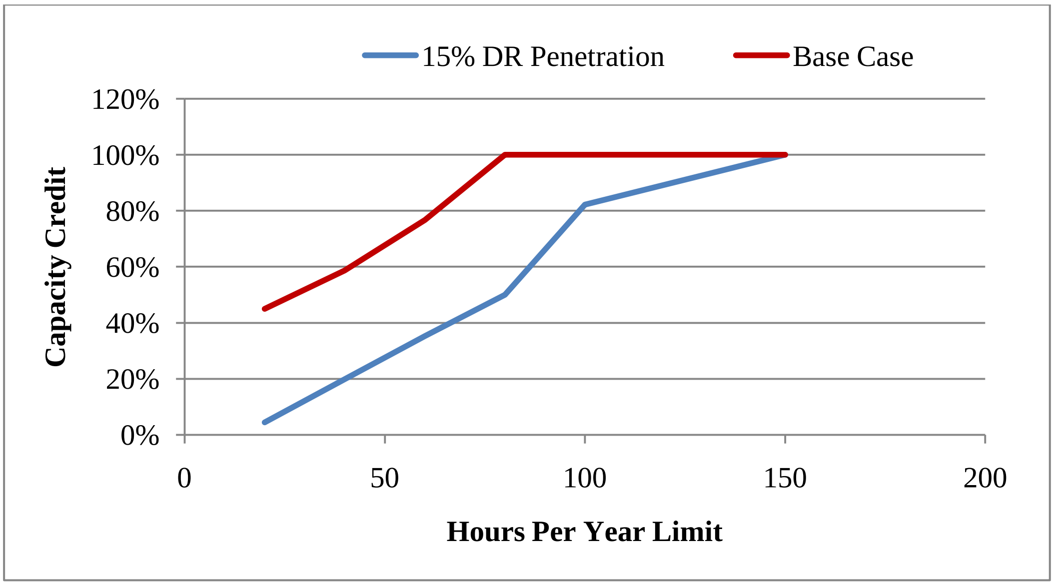
The next step in the evaluation was to determine how the 1-in-10 LOLE and economic reserve margin would change based on moving from 8% to 15% penetration. Table 12 displays the results. Because the DR was still treated as a reliability-only resource, the physical LOLE metric only shifted slightly and the 1-in-10 LOLE target shifted from 9.75% to 11%. This shows that the 150 hour call limits on the resource were almost enough to maintain the same reliability even with a higher penetration. However, the economic reserve margin was impacted more substantially because when the DR was added, a substantial amount of CT capacity had to be removed from the region to keep the same reserve margin level. Now the region is forced to purchase more energy since several thousand MWs of capacity that was being dispatched at less than $100/MWh was removed. Given this, the economic optimal target moves from 13% to 17%.

Table 12. DR Penetration Sensitivity

	Reserve Margin @ 1-in-10 LOLE Standard	Economic Optimal Reserve Margin	Avg. Demand Response Call Hours at 10% RM
Base Case: DR 8% Penetration	9.75%	13.00%	4.5
DR 15% Penetration	11.00%	17.00%	7

The last set of simulations pertaining to DR calculated the capacity credit of the resource assuming different call limits and different penetration levels. For purposes of the analyses, we are defining capacity credit of a resource as the reliability contribution that it provides the system compared to a fully dispatchable resource with 100% availability. So a resource that can only be dispatched 20 hours a year will not provide the same level of reliability as a resource that can be dispatched perfectly for 8,760 hours per year. Figure 18 shows the capacity credit of DR for the base case under different call limits and under a 15% penetration case with the same call limits. The figure shows that in the Base Case (8% penetration level) a 50 hour per year DR resource dispatched for reliability will only provide 63% capacity credit. Under a 15% penetration level, the same resource only provides 28% capacity credit. The higher penetration level would need the capacity more frequently and if it can only be called 50 hours it would be less valuable under that scenario.

Figure 18. DR Capacity Credit

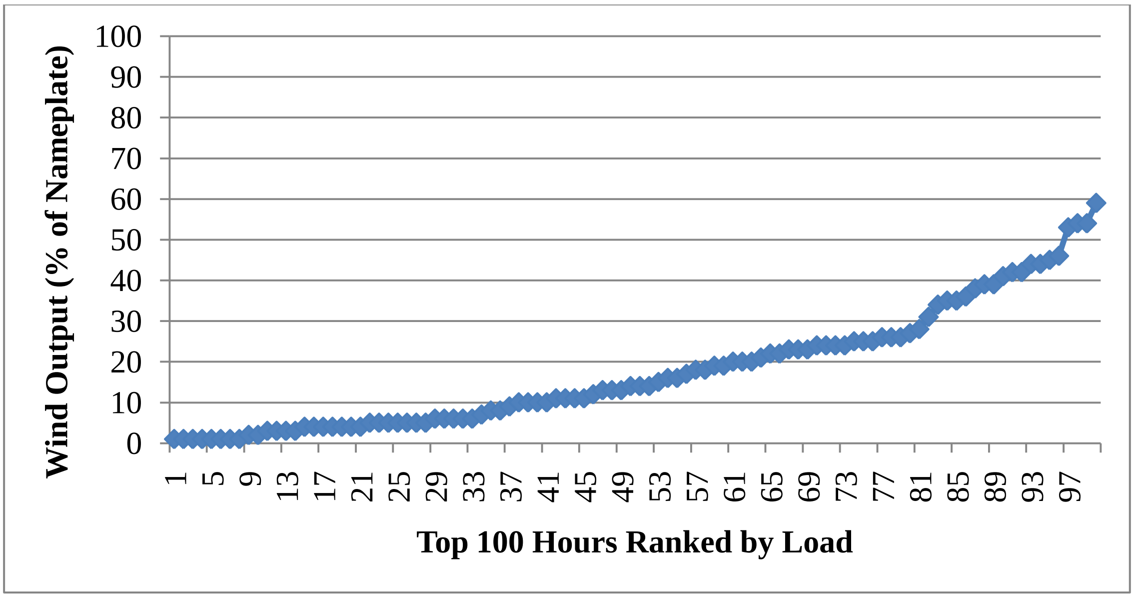


Understanding the risks and benefits offered by DR is critical given the penetration levels that some regions are approaching. Some utilities in Florida are already calculating "generation only" reserve margins and are considering using such a criterion in their resource planning decisions. This is due, in part, because there is uncertainty on how the DR will perform, including DR participant tolerance levels, as they are called upon more frequently. If states are going to consider further implementation of DR, it is important to ensure that the right amount and type are being added and these resources are being incentivized and valued correctly. States will need to understand all the dynamics and risks that could occur with DR. Some of these have been demonstrated in this case study simulation. Further simulations could assist in understanding this dynamic.

B. Intermittent Resource Sensitivities

Intermittent resources have a fundamentally different resource adequacy profile from conventional resources. The forced outage status of thermal generators is nearly completely independent. Fuel supply, transmission issues, and shared facilities can cause some units to be unavailable simultaneously, but typically outages are independent. Intermittent resources such as wind and solar, however, are dependent on weather conditions which are highly correlated across large geographic areas. For example, with a wind fleet of 1,000 MW in a 50,000 MW system, this does not create significant concern. At a higher penetration of 10,000 MW in a 50,000 MW system, the loss of wind resources will be a more significant issue. Because of wind's intermittency, the capacity value or effective load carrying capability (ELCC) of wind is already much lower than its nameplate capacity. Generally, at low penetration, the ELCC of wind should be close to the average output during peak conditions. If peak load occurs in the summer between 2:00 and 4:00 PM, a rough approximation of wind's ELCC would be the average output during these hours. For many regions, this output is between 15% and 25%. For our studied region, the wind output during the top 100 load hours is shown in Figure 19. The distribution is sorted by wind output and not peak load. The average output of wind is 18% of nameplate rating.

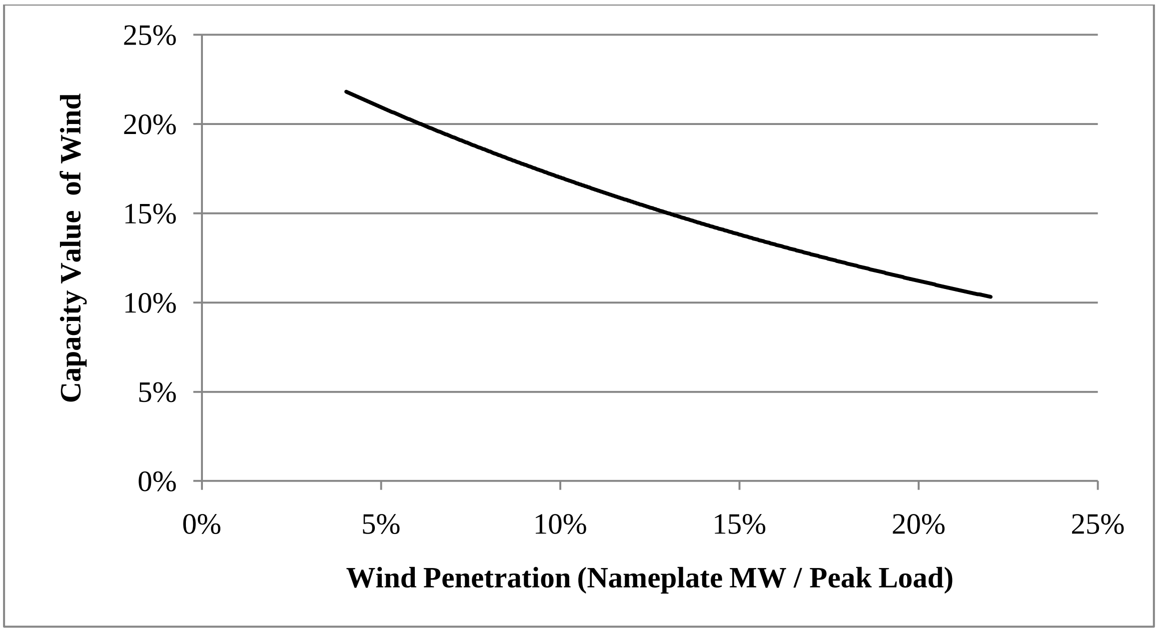
Figure 19. Wind Output During Peak Load Hours



However, this distribution also shows that in some peak hours, the wind output is much less than 18%. At a low penetration of 1,000 MW of nameplate wind, a region giving the wind fleet ELCC credit of 180 MW based on the average output during peak, this is not likely a reliability issue. Getting 180 MW less than expected is not a significant concern. It would be similar to losing a small thermal generator. If the wind fleet is a much larger 10,000 MW, having an output much smaller than the average output during peak conditions has a much larger impact on the system because it would correlate to losing 1,800 MW of capacity - a much more significant event.

To capture this difference, SERVM was used to determine the ELCC of wind at several penetration levels. When increasing the size of the wind portfolio, the same profile was used for all wind, so the correlation was perfect. This assumption is too conservative, because in reality, as penetration increases, a system would get some diversity benefit. But Figure 20 illustrates that as penetration increases, the capacity value or ELCC drops due to the reasons explained above. At low penetration, the ELCC can be slightly greater than the average output during peak if the system is energy limited rather than capacity limited. Having wind available at other times allows the system to conserve energy limited resources such as demand side resources and pumped storage or other hydro in hours that are lower than the peak so that those resources are available during peak hours. At high penetration, the ELCC is approximately half its value at low penetration.

Figure 20. Wind Penetration Study



These simulations did not capture the impact that intermittent resources has on ancillary service needs. Since the output of wind can vary substantially on a minute to minute basis, additional reserves may be necessary to fully integrate the wind profile. This is potentially an additional impact to reliability and warrants further analysis.

As the penetration of intermittent resources increases, regulators need to be aware of and prepared to address the changing impact these resources have on the economics of resource adequacy and on physical reliability.

C. ENERGY STORAGE SENSITIVITIES

One proposed solution for intermittent resources is often to use energy storage technologies to firm up wind and other intermittent resources. Energy storage could address intra-hour uncertainties as well as hourly and daily uncertainties due to the intermittent profiles of wind and solar. The incremental intra-hour needs of regulation, operating reserves, and load following due to wind are well met by energy storage because, for these services, only 1-2 hours of storage may be needed. For the longer term uncertainties, the question of how many hours of storage is adequate to fully back-up wind resources. Would 4 hours of storage be adequate to make the wind energy be dependable? 8 hours? 16 hours?

The answer is likely dependent on the existing system as well as the penetration of intermittent resources. At low levels of penetration, energy storage solutions could likely have a lower peak capacity to energy storage ratio. For example, with only 1,000 MW of wind in a 50,000 MW system, each energy storage installation might only need 2 MWh of storage for every 1 MW the installation is able to deliver on peak. At higher penetrations of wind, each energy storage installation might need 10 MWh of storage for every 1 MW of peak output.

The fundamental issue when crafting an energy storage solution for intermittent resources is to identify the most cost effective solution. Given the right energy storage technology, it may be possible to build enough storage capacity with tremendous energy reserves to be able to fully firm up all wind capacity. But is this economically efficient? Even if the cost of energy storage drops substantially in the future, the ideal economic solution likely includes only firming a portion of the wind fleet combined with a mix of types of energy storage. Additional simulations could be performed to design optimal energy storage resource expansion plans that minimize the cost of integrating wind.

D. Distributed Generation

Distributed Generation (DG) is generation that produces electricity at or near the point of use and is generally small compared to centralized power stations. Distributed generation includes on site wind, solar arrays, micro-turbines, fuel cells, combined heat and power, and back-up or emergency power units. Based on a Department of Energy Report[66] released in 2007, there are an estimated 12 million distributed generation units installed in the U.S. with a combined capacity of approximately 200 GW. The report estimates that 84 GW of this capacity is consumer owned combined heat and power (CHP) systems and the majority of the remaining capacity consists of backup power units used only during emergency situations. These on-site units are generally not much larger than 1 MW in size, but in aggregate represent a large amount of capacity.

From a resource adequacy perspective, the difficulty with distributed generation is that utility system operators typically do not have full control to dispatch the resource during times of peak load. Because of this, the majority of these resources are typically not counted toward a reserve margin. An additional complexity raised by these resources is how load forecasts are accounting for the load that these resources are serving. As discussed in other sections of this paper, the proper counting of resources such as DG, DR, wind, and other energy limited resources is essential in optimal resource adequacy planning. To the extent that distributed generation owners and utility planners can better coordinate dispatch schedules and provide operators assurance that the resource will be available when called, there is potential for these resources to provide capacity in resource plans rather than through construction of new generation facilities. Generally, larger cogeneration and backup resources are counted but because the majority of all DG is less than 1 MW, a large percentage of these resources are not contributing to reserve margin calculations. States should continue to encourage this coordination, when cost-effective, in an attempt to further optimize resource adequacy.

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[66] *The Potential Benefits of Distributed Generation and Rate_Related Issues That May Impede Their Expansion,* retrieved on November 2, 2012 from http://www.ferc.gov/legal/fed-sta/exp-study.pdf

Aside from resource adequacy, states should help foster cost-effective DG by ensuring tariff rates and other subsidies such as investment/production tax credits are properly incentivizing these resources. Because of the size of these resources, new DG does not benefit from the economies of scale of a new traditional centralized power station and may need to make up the difference in order to be economically competitive with these traditional generation sources through specific advantages such as co-generation benefits, transmission benefits, fuel source, or subsidies. Regarding transmission, states should continue to ensure that interconnection rules and guidelines are fair and allow these types of resources to be developed.

X. ALTERNATIVES TO THE 1-IN-10 LOLE CRITERIA

A. NORMALIZED EUE

NERC has recently required all long assessment areas to perform probabilistic reliability studies for their systems and report a new metric which it calls "Normalized EUE". This is the percentage of load that was unserved.

Pros:

- The metric provides more information than LOLE because it incorporates the magnitude of the firm load shed event versus only counting the event.
- The metric is more easily comparable across regions because it calculates the magnitude of EUE as a percentage.

Cons:

- There is currently no threshold in place in the U.S. that has been studied stating that a system should be planned to meet a specific percentage of Normalized EUE.
- Normalized EUE doesn't take into account customer costs.

B. MINIMIZATION OF TOTAL SYSTEM COSTS

As the paper has discussed, assessing the reserve margin which produces the minimum system costs from the perspective of the consumer provides valuable insight.

Pros:

- Evaluating the economics provides customers and regulators with a sense of what the costs are for various levels of reliability and whether or not meeting a 1-in-10 LOLE standard is justified.
- An economic study better portrays the risk of resource adequacy. As seen in the results, reliability events are low probability but high cost events.
- Because firm load shed events are so infrequent, it is difficult to calibrate loss of load expectation models. Analyzing economics allows planners to know whether or not their reliability expectations are reasonable by being able to calibrate their economic results to actual historical costs.

Cons:

- Evaluating the economics alongside physical reliability metrics requires more effort.
- A few key assumptions such as the cost of unserved energy, cost of new capacity, and scarcity pricing have to be developed.

XI. RECOMMEND DETAILED PROCESS AND PROPOSAL TO ASCERTAIN THE ECONOMICS OF RESOURCE ADEQUACY

A. ENTIRE EASTERN INTERCONNECTION ASSESSMENT

Since this case study in this paper only used a subset of the Eastern Interconnection, we propose to the states that there would be value in examining the economics of resource adequacy as well as physical reliability metrics of the entire Eastern Interconnection. Analysis could be performed on an individual region basis as well as for the aggregate Eastern Interconnection. It is expected that an optimal economic reserve margin target for the Eastern Interconnection that is well coordinated and dispatched efficiently would likely be lower than a composite level resulting from target set by individual entities. Another view of the analysis could only analyze societal costs (fuel burn + O&M + unserved energy costs) across the Eastern Interconnection.

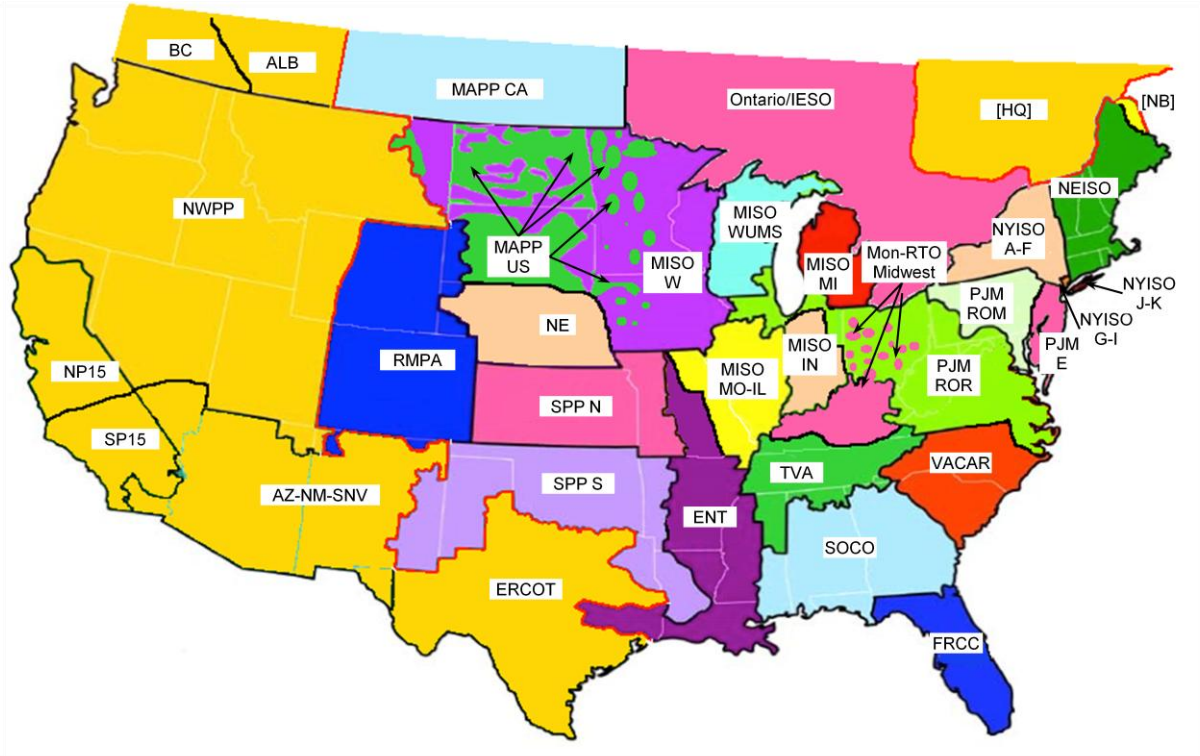
We propose using the EIPC data in a similar fashion to the way the data was used for this study. Load forecasts, fuel forecasts, and unit characteristics could all be obtained from EIPC data because the assumptions have already been well vetted by the participants. The data that would still need to be further developed or gathered to produce accurate resource adequacy results by entity and in aggregate would include the following:

- Distributions of load uncertainty due to weather for the remaining regions
- Distributions of load uncertainty due to economic growth uncertainty
- Actual historical generator availability data (GADS Data) by unit
- Demand resource characteristics
    - Reliability only
    - Economic
    - Call limits
    - Forecasted amounts
- Emergency Operating Procedures
    - Voltage reduction ability
    - Definition of when exactly a firm load shed event occurs (i.e. before or after depleting operating reserves, voltage control, etc)
- Wind and solar profiles by region and correlations to each other
- Hydro variability by region based on historical rainfall
- Energy efficiency projections by region
- Interface capability between regions and distributions around these assumptions representing the interface availability during peak conditions.

Astrape would recommend using a similar approach to the case study included in this paper. SERVM would be necessary to model the major uncertainties surrounding resource adequacy and capture all possible outcomes. It is expected that all benefits and costs associated with adding additional capacity across a range of reserve margins would be tabulated to gain a full understanding of the cost/benefit relationship. At the same time, it would be important to also calculate physical reliability metrics such as LOLE, LOLH, and EUE for all the scenarios simulated.

The topology for the Eastern Interconnection for the recommended study is included in the following figure. The regions within WECC and ERCOT would not be included in the analysis. The regions not already included in this paper's case study include HQ, IESO, NB, NEISO, MAPP US, NE, SPP-N, SPP-S, ENT, SOCO, and FRCC.

Figure 21. Study Topology[67]



The effort required to model the remaining areas in the Eastern Interconnection would not be inordinate given a significant portion has already been done. Astrape would propose incorporating actual historical GADS data rather than using the generic EFOR data provided in the EIPC data. Astrape would also need substantial collaboration regarding emergency operating procedures by each region as well as developing a better distribution of the transfer capability between regions.

Additional sensitivities surrounding market structure, scarcity pricing, demand response, and load forecast error assumptions should also be simulated to understand the impact they may have on the Base Case in this paper. Also the authors suggest simulating analysis using a different marginal resource such as demand response or combined cycle capacity.

It is anticipated that this effort could also result in state by state assessments of both the physical reliability and economic efficiency provided by the resource plans of utilities and other entities.

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[67] Study would not include WECC or ERCOT

B. Additional Reliability Considerations With Evolving Resource Mixes

1. Demand Response Analysis

This paper demonstrated the importance of understanding demand response and how it impacts resource adequacy but many important questions have not been answered. If the full Eastern Interconnection model is developed, more meaningful analysis of DR programs is possible. Also, based on the data developed by the national labs for EISPC regarding demand response, there is much to be learned in this area with additional simulations. Scenarios to be explored could include:

- Simulating the 4 DR penetration possibilities developed by Oak Ridge National Laboratories[68] under the full range of weather, load and unit performance scenarios developed by Astrape. The penetration levels range from 6% - 30% and consist of a number of different types of programs.
- Assessing the energy and capacity value of pricing programs under a range of views of the future, including several of the alternate views explored in the EIPC study.
- Additional simulations assessing the impact of other contract constraints including days per week, hours per day, hours per month.
- Additional simulations to explore the impact of potential customer fatigue and changing price responsiveness.

2. Evaluating the Impact of Intermittent Resources on Operational Reliability

Because SERVM performs a full economic dispatch, the effort performed for the long-term physical and economic reliability assessments could be leveraged to analyze operational reliability. Although SERVM is an hourly model, intra-hour impacts could also be assessed by applying a distribution of 5-minute, 15-minute, and 30-minute uncertainty to the available resources in the model. Results of these simulations would allow planners to quantify the economic costs and reliability impact of increasing penetration of wind and solar from an operational standpoint. The costs of the necessary ancillary services such as regulation, load following, and additional operating reserves could be easily captured, as well as the financial impact of having to over commit resources to be able to ensure reliability will not be a concern. Potential mitigation strategies could also be explored using SERVM to identify the technologies and scheduling practices that protect reliability and minimize system costs in future environments.

3. Probabilistic Transmission Availability Impact

The data needs mentioned above anticipate the need for better transmission information, but do not include simulating probabilistic transmission component failures. SERVM could be used in conjunction with transmission modeling tools such as EPRI's TransCARE[69] to assess the combined generation and transmission reliability for discrete regions in the Eastern Interconnection. The scope for such an assessment has been developed separately by NARUC.

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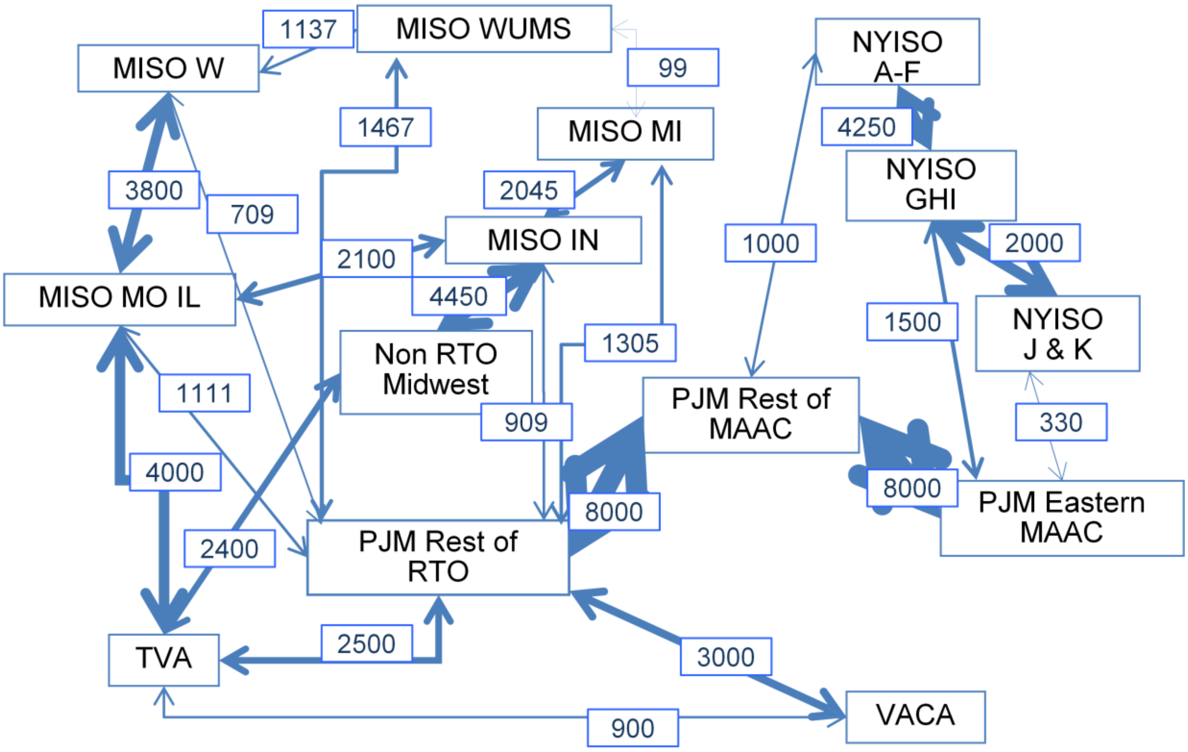
[68] Demand Response Assessment for Eastern Interconnection retrieved on Dec 1, 2012 at http://communities.nrri.org/documents/68668/19533034-7afe-4e7e-98fc-c4b511213871

[69] TransCARE is used is used for reliability assessment of composite generation and transmission systems.

XII. APPENDIX A

For the case study, Astrape Consulting constructed a model that included a significant portion of the Eastern Connection. All of the modeling data was taken from the current EIPC study including load forecasts, existing unit data, and transmission capability between regions. Below is the topology that was used for case study.

Figure A1. Topology



The resource adequacy software used for the case study is the Strategic Energy and Risk Valuation Model (SERVM)[70]. The probabilistic model was specifically designed for this type of analysis because it not only calculates traditional reliability metrics for a system (i.e. LOLE, LOLH) but also incorporates economic commitment and dispatch which allows for economics to be taken into account.

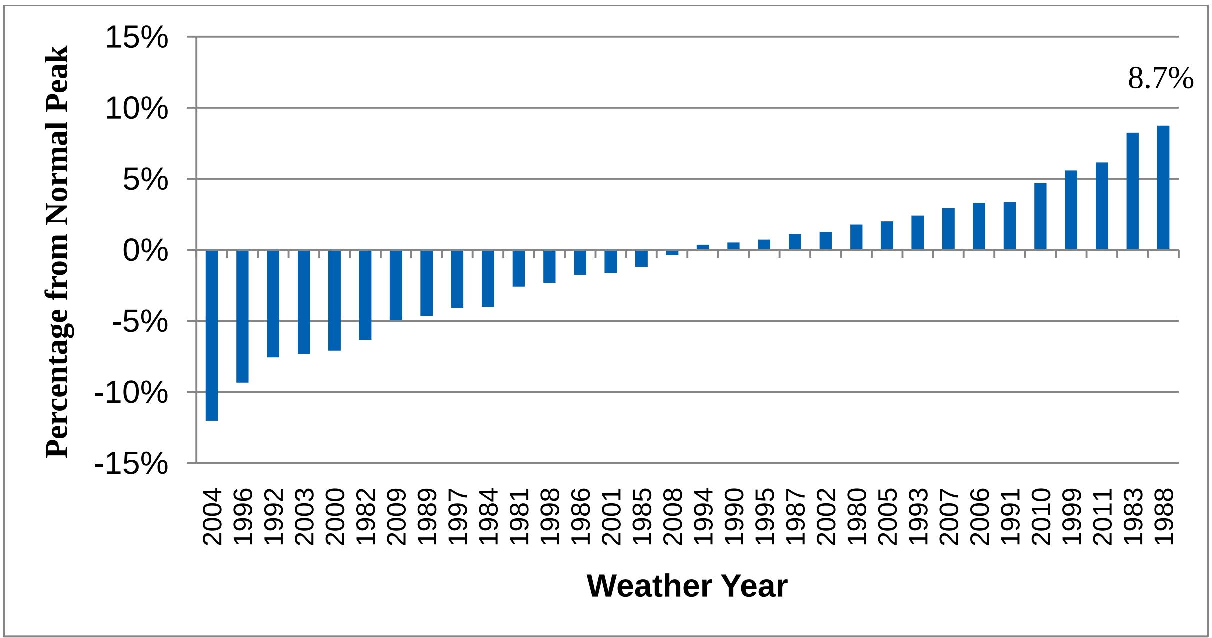
Resource adequacy studies have key attributes that differentiate it from typical production cost modeling studies. First, the study time frame typically examines one year in the near future versus studying longer time frames. This one year is then analyzed for all possible outcomes to assess the probability of a shortfall in capacity. For this case study, the year 2016 was chosen since it provides the lead time for new generation to be installed if reserve margin targets need to be changed. The most important variables driving capacity shortfalls include a combination of the following three uncertainties: weather uncertainty, economic load forecast uncertainty, and unit performance.

[70] SERVM is an economic resource adequacy model that is used by utilities to develop optimal reserve margin targets using economics as well as LOLE.

Weather

Weather uncertainty has an impact on both load and resources. The impact on load was modeled by simulating 32 synthetic load shapes representing the last 32 years of weather. Synthetic load shapes were created by developing a relationship between the last five years of load and temperature history using a neural net model. Each region has a unique load and weather relationship. These relationships were then applied to the last 32 years of weather to create 32 synthetic load shapes for each region. Each of these shapes represent what 2016 load could look like if the region experiences the same weather conditions from a historical year. Each load shape was given equal probability of occurrence in the simulation. The following figure provides an example of how high summer peak load can be above normal peak load for the PJM Rest of MAAC Region.

Figure A.2. Summer Weather Variability on Load for PJM_ROM



The following tables demonstrate the weather diversity incorporated into the loads. The first table shows on average over the 32 years of weather history, where each region is compares to its non-coincident peak load when the entire system peaks. The non-coincident peak of the system is 412,251 MW while the coincident system peak is 394,450MW which represents 4.5% weather diversity across the region.

Table A.1. Weather Diversity

Region	Average Load When Total System is Peaking (MW)	Average Non-Coincident Peak Load (MW)	Load Diversity with Neighbors (Region non-coincidental peak - Region coincidental peak)/(Region coincidental peak) (%)
PJM ROM	29,689	30,031	1.2%
PJM-E	35,731	36,143	1.2%
PJM ROR	105,726	107,319	1.5%
TVA	34,001	35,833	5.4%
VACAR	48,135	50,204	4.3%
NON-MIDWEST-ISO	11,272	11,729	4.1%
NYISO-A-F	11,154	11,934	7.0%
NYISO-G-I	4,220	4,515	7.0%
NY ISO-J-K	16,550	17,708	7.0%
MISO-IN	20,294	21,382	5.4%
MISO-MO-IL	20,434	21,530	5.4%
MISO-W	25,611	29,242	14.2%
MISO-MI	18,906	20,729	9.6%
MISO-WUMS	12,725	13,952	9.6%

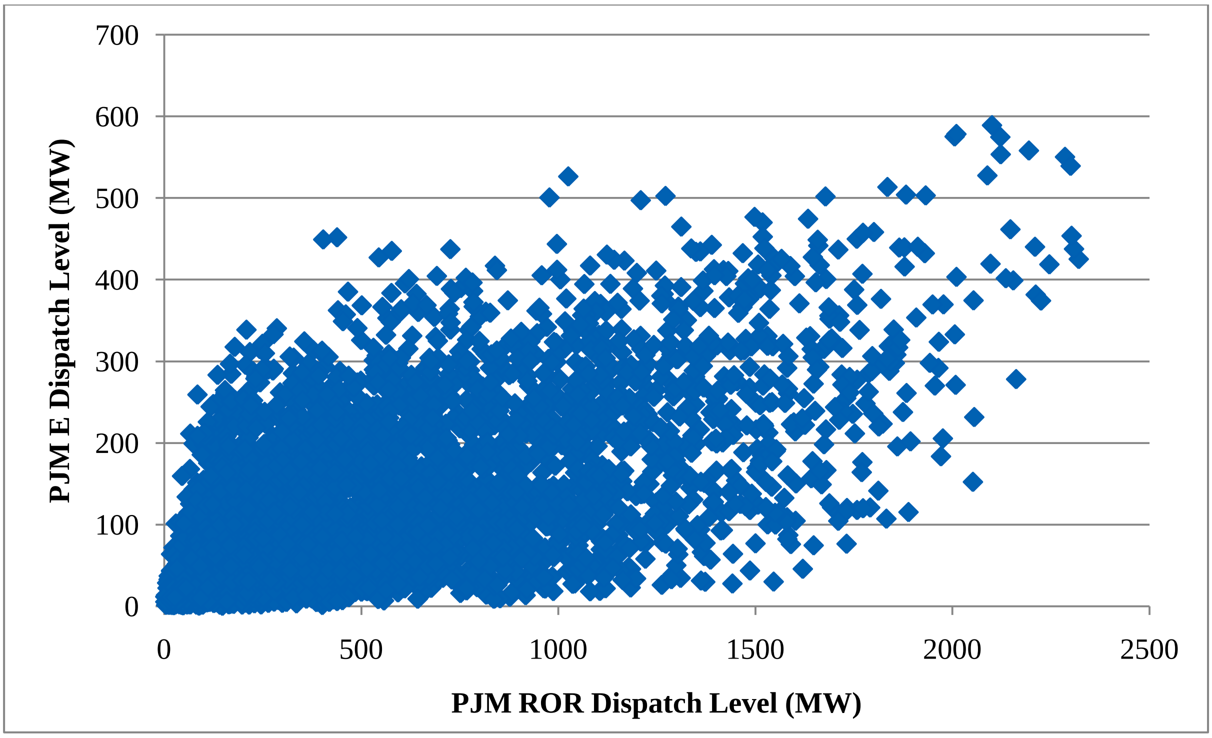
The next table represents the average of how far the neighboring region's load is relative to its own normal peak load in hours when the PJM_ROM is at its peak load. This is an average over 32 years of weather history. So on average, when PJM_ROM is at its peak load, then VACAR is within 6.7% of its normal peak load.

Table A.2. Neighbor Region's Load During PJM_ROM Region Peak

Region	Average Load When PJM_ROM is at its Peak Load (MW)	Average Non-Coincident Peak Load (MW)	Average Diversity with Study Region Peak Load (%)
PJM ROM	30,031	30,031	0.0%
PJM-E	36,143	36,143	0.0%
PJM ROR	103,682	107,319	3.4%
TVA	33,386	35,833	6.8%
VACAR	46,848	50,204	6.7%
NON-MIDWEST-ISO	10,880	11,729	7.2%
NYISO-A-F	11,022	11,934	7.6%
NYISO-G-I	4,170	4,515	7.6%
NY ISO-J-K	16,354	17,708	7.6%
MISO-IN	19,264	21,382	9.9%
MISO-MO-IL	19,397	21,530	9.9%
MISO-W	24,571	29,242	16.0%
MISO-MI	18,051	20,729	12.9%
MISO-WUMS	12,149	13,952	12.9%

Weather uncertainty also impacts the operation of hydro, wind, and solar resources. To take this into account, historical hydro energy data from each region was used to capture the amount of hydro energy available in each of the 32 weather years. For wind resources, the 2004 - 2006 EWITS data was utilized. The model draws stochastically by month and day from the 3 year period ensuring that the correlation from region to region is maintained. In other words, if July 5, 2006 was randomly drawn, then the profiles for all regions from that day were utilized. In examining the data, there was a significant correlation between regions as shown in the following figure. In hours when the PJM wind output was low, it was likely to be low in other regions as well.

Figure A.3. Wind Correlation between Regions (PJM_East/PJM_Rest of RTO)



The table below shows the capacity credit given to intermittent resources by region for the case study.

Table A.3. Capacity Credit of Intermittent Resources

NEEM Region	Technology	Capacity Credit
All Regions	Photovoltaic	30%
All Regions	Solar Thermal	30%
All Regions	Offshore Wind	20%
New York	Wind	10%
PJM (-E, -ROM, -ROR)	Wind	13%
TVA	Wind	12%
All Other Regions	Wind	15%

Economic Load Forecast Error

The second uncertainty - load growth forecast error - is the measure of the extent to which load forecasters will underestimate or overestimate economic growth for the next several years depending on the year being studied. The following distribution was used for the case study. This distribution was developed from a historical analysis of how well the Congressional Budget Office was able to forecast GDP four years in the future. The GDP uncertainty was converted to load uncertainty by multiplying by 40% - the assumed relationship of load growth to economic growth. The figure shows that in the most extreme case (lowest probability), load growth could be under forecasted by 5% over a four year period.

If it is assumed that demand response is the marginal resource, then it is likely that the economic load forecast error could be reduced to examine uncertainty over 1 – 2 years. The analysis completely changes under this approach because the capacity costs and benefit of a marginal DR resource are likely less than a marginal CT. The fact that the acquisition of DR is not unlimited also poses a concern in the authors' opinion.

Figure A4. Economic Load Forecast Error

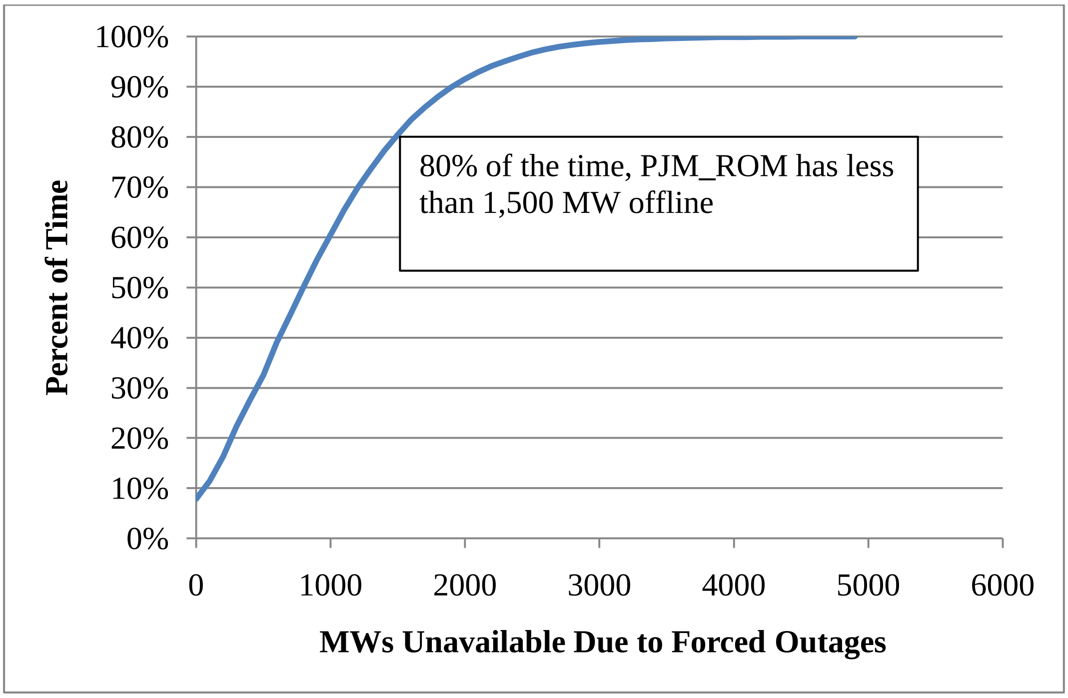
Load Forecast Error	Probability
5.11%	6.25%
3.90%	18.75%
0.55%	31.25%
-1.76%	18.75%
-2.90%	12.50%
-4.54%	12.50%

Unit Performance

The last major driver is unit performance. It is important to simulate the percent of time that a system will have a significant amount of generation offline due to forced outages, including partial outages. The model uses Monte Carlo techniques to simulate random generator failures. SERVM users actually enter in time to fail and time to repair distributions instead of a unit Equivalent Forced Outage Rate (EFOR). For this study, Astrape scaled distributions to achieve the target EFORs that were used in the EIPC Study. It should be noted that the EFOR data provided in the EIPC study was generic by unit type and that real historical GADS data would be needed for these results to provide more than an indicative conclusion.

The following chart shows a distribution representing the amount of MWs offline due to forced outage as a percentage of time. The figure shows that it is expected to have approximately 800 MW of capacity offline in a given hour, but that there are iterations where there can be several thousand MWs offline in a given hour. The chart also shows that 80% of the time the region will have less than 1,500 MW offline due to forced outages.

Figure A.5. Unit Performance Distribution



Hydro Modeling

SERVM utilized 32 years of historical hydro energy in the model. The variability of river flows can impact resource adequacy greatly. SERVM models the resources as either run of river, minimum flow constraints, or peak shaving. The total hydro capacity for each region was separated into the three categories. Run of river is defined as providing constant capacity for all 8760 hours of the year. The minimum flow constraints force the unit to be dispatched for at least a certain amount of hours each day at a certain capacity level. SERVM optimizes the dispatch around the peak for its peak shaving hydro resources.

Pump Storage Modeling

The pump storage resources are dispatched based on economics. The resources will pump during off peak hours and generate during peak hours if economic.

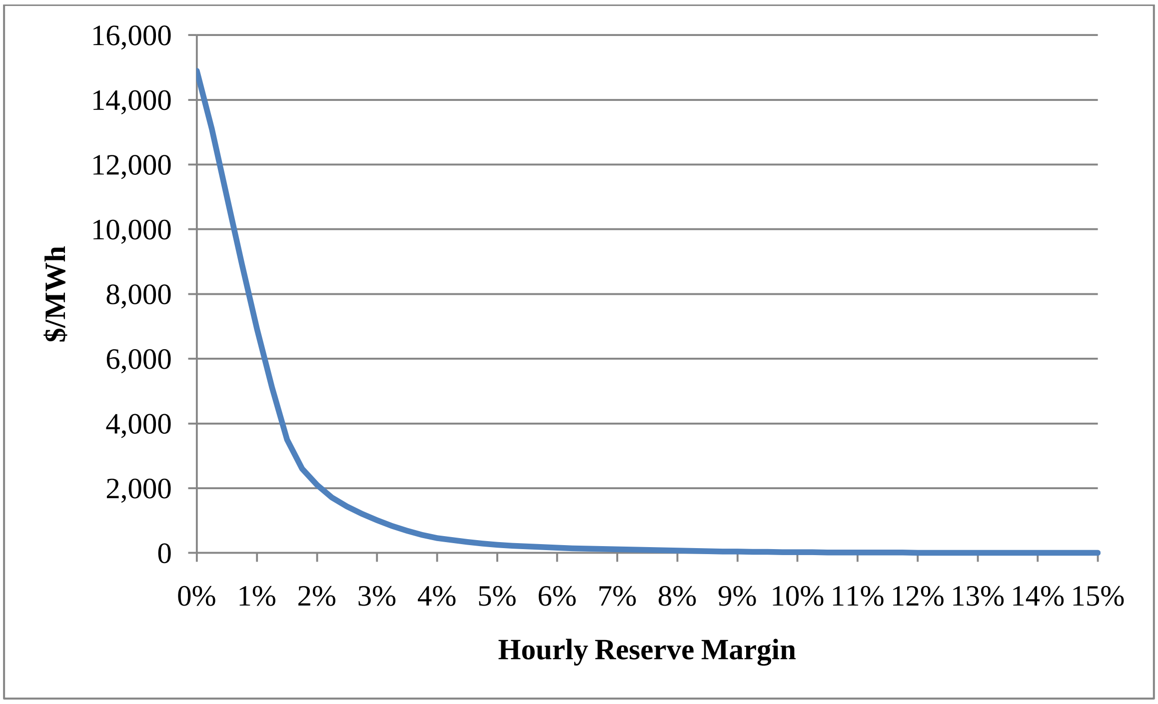
Demand Response Modeling

Demand response resources are modeled as capacity with specific call limits and strike price. For this case study, all demand response was given call limits of 150 hours per year and treated as reliability only with a dispatch price of $2,500/MWh. In other words, demand response was only called after all other alternative have been exhausted including expensive market purchases.

Scarcity Pricing

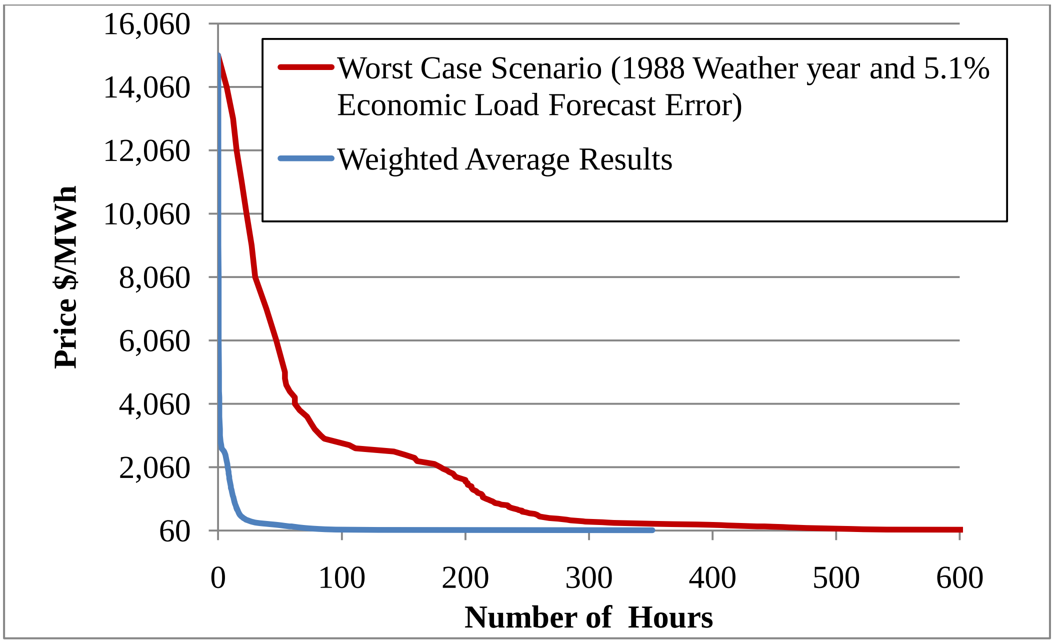
A scarcity pricing curve was developed by Astrape based on past experience of looking at historical market prices in different regions across the country. As the hourly reserve margin for a region decreases, the scarcity price approaches the VOLL. The following figure shows the curve that was actually used in the case study. The 0% level represents the point at which firm load is shed in order to maintain 2% spinning reserves in the case study. Because the modeling takes into account recent weather years, the authors were able to compare energy margins from the model to actual PJM energy margins in 2010-2011 to get comfortable with the scarcity pricing curve.

Figure A6. Scarcity Pricing Curve



Based on the base case results, the following figure shows a price duration curve at a 10% reserve margin level for the weighted average of all scenarios and the worst scenario simulated shows the number of hours that are expected to occur at different market price thresholds. As expected, it is seen that prices above $2,000/MWh are rare.

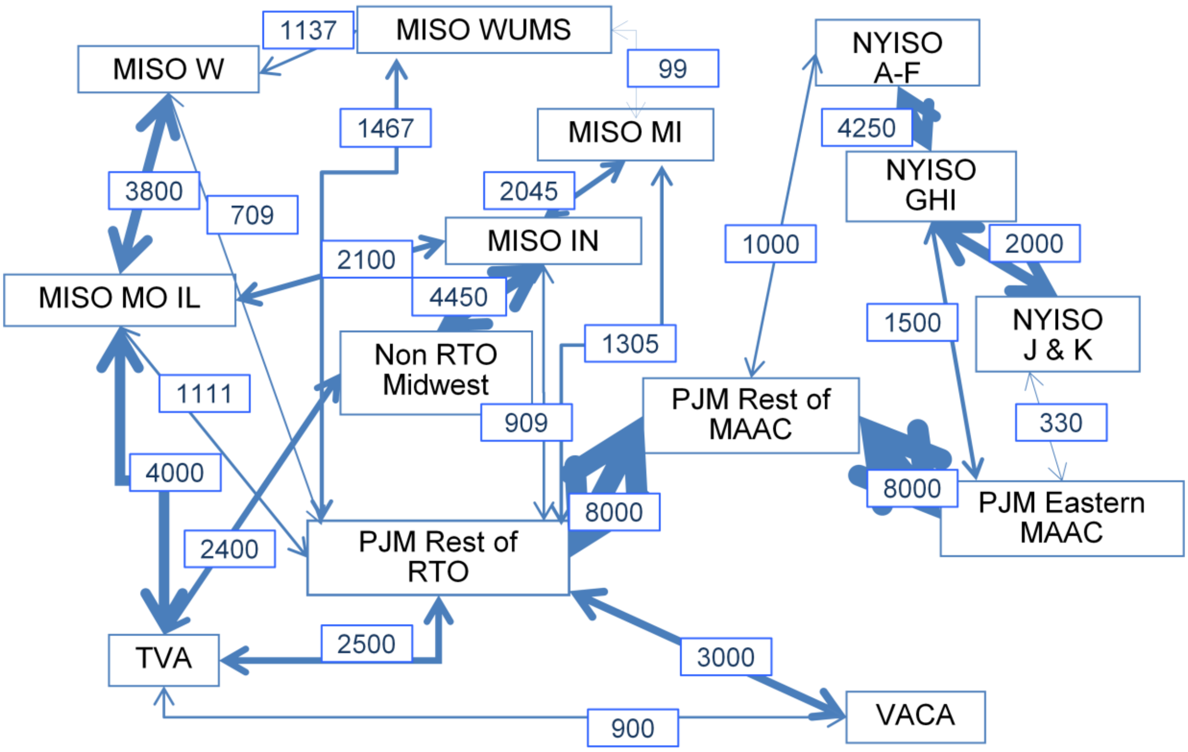
Figure A.7. Frequency of Scarcity Pricing @ 10% Reserve Margin



Transmission Interface

The following figure shows the transmission limits that were used for the Case Study which were direct inputs from the EIPC study. To perform more accurate simulations, Astrape suggests developing availability distributions for these interface limits rather than entering a constant value.

Figure A8. Transmission Interface Limits



Neighbor Modeling

SERVM's market clearing algorithms allow regions to share resources based on economics but subject to transmission limits. For example, if the TVA region is short capacity in a given hour, then their initial market price is equal to the VOLL. If VACAR is long, then VACAR can provide resources to lower the market price in TVA. If there was unlimited transfer capacity, then all regions would have the same hourly market price curve.

It should be noted that SERVM allows users to designate which resources can be shared. For this study, regions were not allowed to dispatch demand response resources in order to sell to other regions. Figure A.8 shows the target reserve levels for each NEEM Region in the study.

Figure A.9. Neighbor Target Reserve Margins

Reserve Margin Area	Reserve Requirement	NEEM Region(s)
MISO	17.4%*	MISO_IN
		MISO_MI
		MISO_MO-IL
		MISO_W
		MISO_WUMS
NonRTO_Midwest	14.0%	NonRTO_Midwest
NYISO	16.5%*	NYISO_A-F
		NYISO_GHI
		NYISO_JK
NYISO_GHI_JK	-5.0%	NYISO_GHI
		NYISO_JK
NYISO_JK	-8.0%	NYISO_JK
PJM	15.3%*	PJM_E
		PJM_ROM
		PJM_ROR
PJM_E	-2.2%	PJM_E**
TVA	15.0%	TVA
VACAR	14.0%	VACAR

** Based on coincident peak in reserve margin area.*

*** For purposes of this study, set equal to actual 2010 Reserve Margin*

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XIV. LIST OF ACRONYMS

CAISO	California ISO
CONE	Cost of New Entry
CT	Combustion Turbine
DR	Demand Response
ELCC	Effective Load Carrying Capability
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
FRCC	Florida Reliability Coordinating Council
IESO	Independent Electricity System Operator
IOU	Investor Owned Utility
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
LSE	Load Serving Entity
LOLE	Loss of Load Events
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
MAAC	Mid Atlantic Area Council
MAPP	Mid Continent Area Power Pool
MISO	Midwest Independent System Operator
NERC	North American Reliability Council
NPCC	Northeast Power Coordinating Council
NWPP	Northwest Power Pool
NYISO	New York Independent System Operator
PJM	PJM Interconnection
SERC	Southeast Reliability Corporation
SERVM	Strategic Energy and Risk Valuation Model
SPP	Southwest Power Pool
TVA	Tennessee Valley Authority
VOLL	Value of Lost Load
WECC	Western Electricity Coordinating Council