UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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North American Electric	)	Docket No. RM10-10
Reliability Corporation	)	
	)	

COMMENTS OF JAMES F. WILSON
ON PROPOSED RELIABILITY STANDARD BAL-502-RFC-02:
PLANNING RESOURCE ADEQUACY ANALYSIS, ASSESSMENT AND DOCUMENTATION

Contents

I. Introduction

1. My name is James F. Wilson. I am an economist, principal of Wilson Energy Economics, and an affiliate of LECG, LLC, with over 25 years of consulting experience to the electric power and natural gas industries. In recent years I have been involved in the stakeholder process around which PJM Interconnection, L.L.C. ("PJM") calculates its Planning Reserve Margin according to the reliability standard BAL-502-RFC-02 that is the subject of this proceeding. I have built a model that recreates PJM's Planning Reserve Margin calculations and been involved in other aspects of planning, forecasting and markets related to resource adequacy on the PJM system. Recently I authored a paper evaluating the "one day in ten years" reliability criterion that is included in BAL-502-RFC-02, from which excerpts were published in Public Utilities Fortnightly in the spring of 2010.[1] I have also been involved with issues around PJM's Reliability Pricing Model ("RPM") capacity construct through which PJM acquires commitments to provide capacity to meet the indicated Planning Reserve Margin. Additional information on my experience and qualifications is available at www.wilsonenec.com.

2. My work on these issues has primarily been supported by representatives of consumer interests, including consumer advocates, state commissions, industrial consumers and electric distribution companies. However, the views expressed in these comments are my own and do not necessarily represent the views of any current or past client.

3. In this proceeding, the North American Electric Reliability Corporation ("NERC") has filed for Commission approval the regional reliability standard BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation. In the Notice of Proposed Rulemaking ("NOPR"), the Commission requested comment on several questions while proposing to approve the standard.

4. In Order 672,[2] the Commission provided guidance on how it would review reliability standards, rejecting the notion that it should presume that a proposed Reliability

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[1] Wilson, James F., *One Day in Ten Years? Resource Adequacy for the Smart Grid*, November 2009; *Reconsidering Resource Adequacy (Part 1): Has the One-Day-in-Ten-Years Criterion Outlived Its Usefulness?*, Public Utilities Fortnightly, April 2010; *Reconsidering Resource Adequacy (Part 2): Capacity Planning for the Smart Grid*, Public Utilities Fortnightly, May 2010, all available from www.wilsonenec.com.

[2] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, 18 CFR Part 39, (Issued February 3, 2006), Docket No. RM05-30-000 ("Order No. 672").

Standard developed through an ANSI-certified process automatically satisfies the statutory standard of review (P 338). In particular, in Order 672 the Commission stated that, among other things, a reliability standard:

- should be based on actual data and lessons learned from past operating incidents, where appropriate (P 324);
- must be designed to achieve a specified reliability goal (P 324);
- must contain a technically sound means to achieve this goal (P 324);
- should be clear and unambiguous regarding what is required and who is required to comply (P 325);
- should achieve its reliability goal effectively and efficiently, but does not have to reflect the optimal method or "best practice" (P 328); and
- should be designed to have no undue negative effect on competition and should not create an undue advantage for one competitor over another (P 332).

5. The Commission called for a reliability organization proposing a standard for approval to explain in its application how well the proposed standard meets these and other factors (P 337).

6. In the following sections I first provide broader comments on the approach to resource adequacy represented by BAL-502-RFC-02. Later sections provide more detailed comments on the analytical approach and "one day in ten years" resource adequacy criterion called for under the standard, and address some of the questions raised by the NOPR.

II. Comments on the Overall Approach to Resource Adequacy

A. The Standard affects billions of dollars in capacity costs and transmission investments and warrants a thorough review

7. Reliability standard BAL-502-RFC-02 ("Standard") is different from other reliability standards in that it addresses long-term resource adequacy – the amount of capacity considered needed to provide an adequate level of protection against a need to curtail firm customers to balance electricity supply and demand during peak periods. The Standard only requires performing a resource adequacy study and calculating a Planning Reserve Margin ("PRM"), it does not require actions to ensure capacity is built to achieve the PRM.[3] However,

[3] An earlier version of the standard (BAL-502-RFC-01, approved by RFC Board of Directors March 9, 2006) required documentation of an agreement to enforce the PRM for the upcoming planning year (R4), and required load-serving entities to secure the resources needed to meet the PRM for the upcoming planning year (R5).

PJM acquires the capacity needed to satisfy its PRM[4] through its RPM capacity construct, and other Planning Coordinators also take actions to achieve the identified PRMs. The analysis and calculation specified in the Standard also influence PJM's analysis of the need for major new transmission facilities. Therefore, unlike other reliability standards, BAL-502-RFC-02 has a significant impact on markets, revenues to generators, and cost to consumers, including billions of dollars of cost associated with RPM and transmission projects.

8. The substantial impact on capacity prices and costs has resulted in increased stakeholder attention to the details of these calculations in recent years. This proceeding presents an opportunity to address issues that have been raised, or may in the future be raised, about how PJM (and other Planning Coordinators) apply the Standard and determine the amount of generation and transmission capacity they will acquire for their regions and various subregions. Furthermore, while BAL-502-RFC-02 is only applicable to entities within the ReliabilityFirst Corporation ("RFC") footprint, NERC expresses the expectation (p. 17) that the Standard "will serve, upon approval and implementation, to inform the continent-wide standard drafting effort currently underway." Consequently, this is a unique and particularly important standard that warrants a thorough review.

B. The Standard is an element of an administrative approach to resource adequacy that gained acceptance under very different industry circumstances; with increasingly price-responsive demand and other market developments, this approach may not be well suited to current and future conditions

9. Evaluating resource adequacy based on the LOLE approach with the "one day in ten years" ("1-in-10") reliability criterion is a well-established practice going back decades. There are other reasonable approaches to determining capacity needs for resource adequacy;[5] these comments focus on the LOLE approach that is specified in the Standard.

[4] PJM uses the terms Installed Reserve Margin ("IRM") and Forecast Pool Requirement rather than PRM. The details of the annual analysis to determine PJM's IRM are documented in an annual Reserve Requirements Study. The most recent such study is the 2010 PJM Reserve Requirements Study, September 30, 2010 ("RRS 2010").

[5] Examples of other reasonable approaches to planning for resource adequacy: A utility could identify an extreme peak load "Design Day" and an extreme condition regarding plant outages, and plan the system to be able to serve all load under such circumstances, properly adjusted over time for load growth and changing plant performance. This would provide a transparent and easily communicated basis for capacity needs. Or, a utility could attempt to quantify and balance a wide range of costs, risks and benefits of incremental capacity in a probabilistic cost-benefit modeling exercise. This would capture more relevant considerations, but would also be more complex and the results would rely on many assumptions and forecasts about which reasonable people could disagree.

10. The LOLE approach with the "one day in ten years" criterion is a highly conservative approach to resource adequacy that became widely accepted decades ago when peak loads were growing rapidly and generally had to be met by constructing large power plants that required years to build. Under such circumstances, building too little capacity risked frequent shortages, while any excess capacity would be quickly absorbed by load growth. Under such circumstances, the "over/under" risk considerations suggested erring on the side of building more plants and sooner, so conservative assumptions were often adopted for these studies. In addition, unlike outages due to distribution system disturbances, curtailments due to capacity shortage seem preventable – a few more megawatts would have reduced or eliminated the need for curtailments – and thus suggest a failure by utility planners and regulatory authorities to ensure that enough capacity was built. Highly conservative resource planning may make more sense for utility planners and regulators than for the consumers who bear the cost of the excess capacity.

11. In recent years load growth has slowed (peak load growth is expected to average about 1% per year on the PJM system after 2014[6]), and there are now many incremental resources that can be mobilized in a relatively short time frame, such as demand response, upgrades at existing plants, incremental imports from neighboring regions, some renewables, and deferred retirements, to name a few. On the PJM system, over 80% of the incremental capacity offered through the RPM capacity construct over the past several years has been such short-lead-time resources.[7] With slower load growth, there is now a much greater chance that excess capacity will remain excess for years, and there is also much more flexibility to adjust resource adequacy from year to year as needs evolve. Highly conservative approaches to determining capacity requirements, based on the LOLE approach and 1-in-10 criterion called for under the Standard, were better suited to past than to present conditions.

12. For nearly all goods and services, markets are trusted to expand capacity as needed and there are no administrative standards pertaining to capacity requirements (such as the Standard represents) or rules that impose obligations on consumers to pay for the administratively-determined capacity requirements. While at one time many experts believed

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[6] PJM Load Forecast Report January 2010 or draft, December 20, 2010, Table B-1.

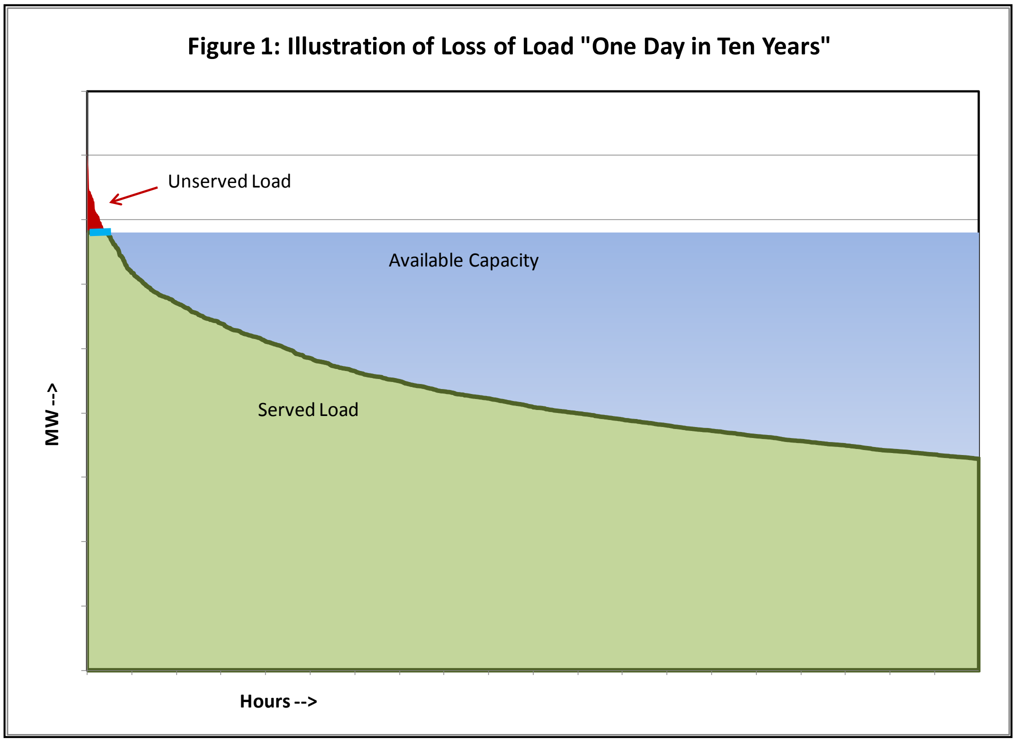
[7] PJM, 2013/2014 RPM Base Residual Auction Results, Table 9 p. 20.

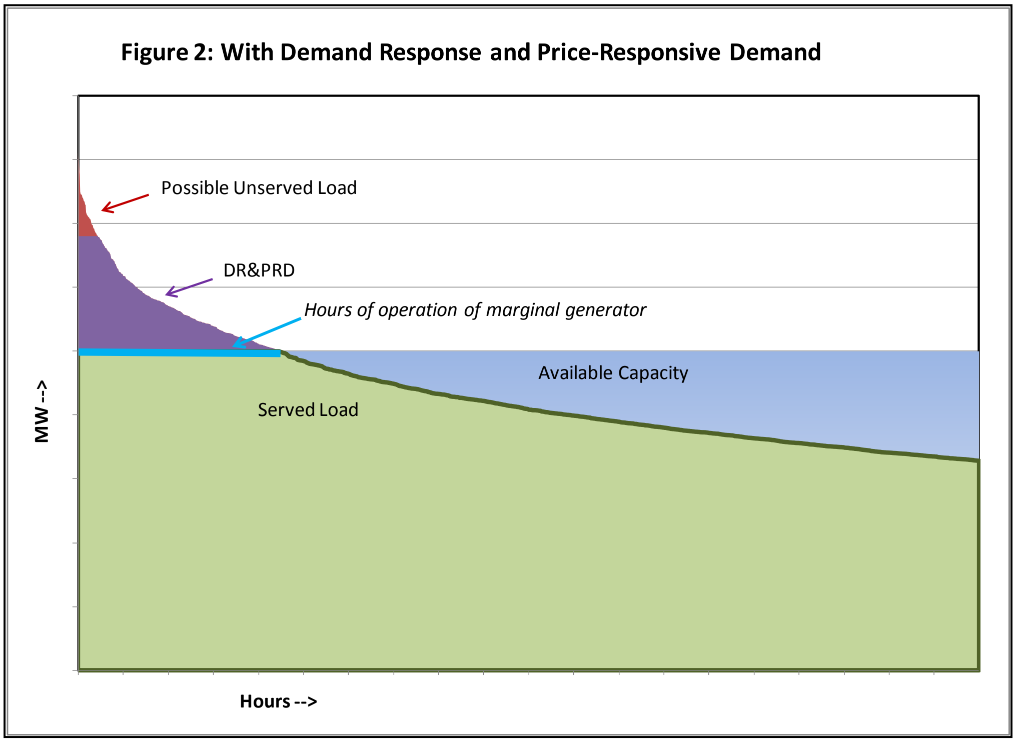
capacity expansion in restructured electricity markets should occur under market forces, concern arose that markets would not provide the traditional "one day in ten years" level of resource adequacy. This concern about restructured markets led, in some regions (such as PJM), to administratively-determined, mandatory capacity obligations and complex, controversial mechanisms such as RPM to acquire commitments to fulfill these obligations.

13. As the demand side becomes more engaged in the form of demand response and price-responsive demand, the role of administrative capacity requirements and capacity mechanisms can decline and ultimately be eliminated. When demand and supply can be balanced through pricing during peak periods or when reserve shortages occur, a need for involuntary curtailment of load should become increasingly unlikely even though a lower fraction of the potential "unrestricted" peak demand will be served with generating capacity. With demand response and price-responsive demand being called upon in more high-load hours, the marginal generator will operate in more hours and earn more revenues than in the past, when it might have expected to run only "one day in ten years" and, therefore, required a substantial capacity payment.[8]

14. This evolution is illustrated in Figures 1 and 2. Figure 1 suggests the traditional circumstance under which generating capacity is built to meet all but the highest peak loads, and loss of load occurs rarely ("one day in ten years", in principle). The red area in Figure 1 suggests the very rare involuntary curtailment, and the light blue line suggests the hours when the highest-cost, marginal generator would operate – very few hours, and only when involuntary curtailment of load is occurring or imminent. Figure 2 shows how the situation changes when there is a considerable amount of demand response and price-responsive demand on the same system (and, let's assume, wholesale and retail pricing approaches that allow prices to rise to high levels when necessary to make use of the price-responsive demand). As Figure 2 suggests, with demand response and price-responsive demand, less generation is needed and the amount of generating capacity is lower. However, the marginal generator operates in many more hours (as suggested by the light blue line in Figure 2), and, in addition, likely earns considerably more energy and ancillary services revenues, as prices will often be elevated in these hours when demand

[8] This is further developed in Wilson, James F., *Reconsidering Resource Adequacy (Part 2): Capacity Planning for the Smart Grid*, Public Utilities Fortnightly, May 2010.





response and price-responsive demand are activated. With demand response and price-responsive demand (and, in addition, new capacity now generally receiving revenue guarantees such as long-term contracts in order to be built), the marginal generator may no longer need a capacity payment, and capacity mechanisms such as RPM will either set very low prices or perhaps can be eliminated. The pink area labeled “possible unserved load” corresponds to the red area in Figure 1, but if prices are allowed to rise to very high levels, supply and demand might be balanced even in the highest load hours without involuntary curtailment.

15. BAL-502-RFC-02 could potentially serve as an impediment to the transition from resource adequacy based on administrative capacity mechanisms to market-driven resource adequacy based on pricing and market and contractual revenues. As a Commission-approved reliability standard, it could be more difficult to change the Standard and current policies for achieving resource adequacy based on it. In addition, policies based on the Standard have led and are likely to continue to lead to excess generating capacity, which depresses energy and ancillary services prices, fostering continued dependence on capacity payments and discouraging the further development of smart meters, smart devices and price-responsive demand. Note that if, in Figure 2, the amount of generating capacity were higher, such as in Figure 1, the demand response and price-responsive demand would not be needed, the marginal generator’s hours of operation would be as in Figure 1, and its revenues would likely be even lower than under the circumstances of Figure 1. It is important that capacity procurement be adjusted to anticipate the role of demand response and price-responsive demand, and the Standard calls for a conservative approach under which this might occur only with a substantial lag.

16. The evolution from administrative resource adequacy standards and capacity mechanisms toward market-driven capacity expansion should be a priority for the Commission. Capacity constructs such as RPM and ISO New England’s FCM have been and will always be highly controversial because they lead to billions of dollars in payments from consumers to capacity providers without a clear impact of these payments in the form of new power plants or deferred retirements; most of the payments go to existing generators that have no plans to retire. These mechanisms are also controversial because they are highly administrative and determine the magnitude of the prices and payments based on concepts of questionable validity[9] and

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[9] That some of the fundamental concepts around which RPM was designed are flawed is explained in Wilson, James F., *Forward Capacity Market CONEfusion*, Electricity Journal Vol. 23 Issue 9, November 2010. In particular, this article explains that these mechanisms are designed based on assumptions about how power plants will be financed and bid into capacity market mechanisms that were always unsound and have now been disproven by several years of auction results.

various somewhat arbitrary administratively-determined rules and parameters that have a substantial impact on capacity prices and costs.

17. In recent years, PJM's RPM mechanism has imposed enormous, unnecessary costs on consumers to satisfy capacity requirements that were identified according to the Standard and later proved excessive. PJM's policies call for acquiring commitments to meet the PRMs three years in advance of each delivery year. PJM's recent capacity requirements (based on PRMs applied to highly speculative peak load forecasts based on highly optimistic forecasts of economic growth[10]) have been far in excess of actual needs (and, for delivery years that have not yet arrived, far in excess of needs according to updated forecasts). This has driven up capacity prices unnecessarily and led to billions of dollars of excess and unnecessary consumer cost. A well-functioning competitive market would never have resulted in capacity being contracted this way, in what has amounted to a series of highly speculative three-year-forward purchases. Because such capacity mechanisms are highly administrative and controversial and have a very poor record of cost/benefit, it should be a Commission priority to transition away from them.

C. The Standard may require clarification or modification to ensure it contains a technically sound means and results in achieving the reliability goal efficiently

18. The Standard calls for the Planning Reserve Margin to be determined through a probabilistic analysis such that the Loss of Load Expectation (LOLE) does not exceed 0.1 events per year ("one day in ten years"). The remainder of my comments focus on various details of this technical approach ("LOLE approach") and the specified reliability criterion ("one day in ten years"). I will explain that the 1-in-10 criterion does not appear to lead to PRMs that achieve a reasonable balance between the marginal costs and benefits of capacity; it may be an order of magnitude more stringent than this principle of economic efficiency would justify. The 1-in-10 criterion also appears to call for resource adequacy that is far out of line with level of reliability most customers actually receive, in light of the much greater frequency of distribution system outages.

[10] PJM's recent load forecasts have been driven by economic forecasts far more optimistic than the contemporaneous consensus of professional economic forecasters. PJM's draft 2011 forecast (Dec. 2010) is much lower than all previous forecasts because the underlying economic forecast, while still well above the consensus, has been lowered in recent months.

19. The LOLE approach is explicitly probabilistic and requires a probabilistic analysis requiring many assumptions. However, conservative values are often adopted; this is inconsistent with the fundamental goal of calculating the LOLE that corresponds to any PRM and biases the PRM higher. In particular, conservative assumptions about the potential for assistance from neighboring systems are often adopted and lead to excessive PRMs.

20. It has been recognized that the LOLE approach is likely to give very different results depending upon the geographic scope of each application and the manner in which regions adjacent to the study region are represented. For the Standard to provide a "common criterion" for assessing resource adequacy (NOPR P 11) and a technically sound approach, it may need to be more specific about how the analysis is performed with regard to the selected geographic scope and treatment of transmission constraints both within and outside the study area. I also explain why it would not be technically sound or efficient to reflect constrained sub-areas in the PRM calculation, or to impose more stringent resource adequacy criteria on constrained sub-areas out of concern that such constraints diminish compliance with the 1-in-10 criterion.

21. The following sections develop these and other points, and identify several areas where further evaluation may be warranted to determine whether the Standard meets the Commission's criteria or some clarification or modification is needed.

III. Comments on the "One Day in Ten Years" Resource Adequacy Criterion

22. The Standard calls for calculating a PRM that will result in "the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed … being equal to 0.1. (This is comparable to a "one day in 10 year" criterion)." Thus, the Standard allows some (very low) frequency of anticipated load loss, in recognition of the fact that it would be excessively expensive to attempt to build sufficient capacity to eliminate all chance of loss of load.

23. The Commission's review requires that a proposed reliability standard achieve its reliability goal "effectively and efficiently" (Order 672, P 328). The NERC Filing states (p. 15) that the reliability standard will help the industry achieve the reliability goal effectively and efficiently by providing "a common framework" for resource adequacy analysis, assessment and documentation. In addition, the filing states (p. 10):

> "Experience has demonstrated that correlating generating capacity and customer load in a "loss of load" methodology with a target of "one day in 10 year" criterion has provided adequate generating capacity in real time operation (at some times in conjunction with operating measures such as voltage reduction and exercising interruptibles) to supply all customer firm loads, even under extreme conditions."

24. However, the NERC Filing makes no claim that the "one day in ten years" reliability criterion (or "1-in-10") achieves the reliability goal efficiently. In particular, the NERC filing makes no claim that planning and building capacity based on this criterion appropriately balances resource adequacy with its cost.

A. The "one day in ten years" reliability criterion does not appear to balance the marginal cost and margin benefit of incremental generating capacity

25. Economists have questioned the "one day in ten years" criterion for many years.[11] In my recent paper[12] I evaluated the "one day in ten years" resource adequacy criterion and found it to be roughly an order of magnitude too stringent, based on a comparison of marginal cost and marginal benefit, and also other considerations such as the (much higher) frequency of distribution system outages.

26. The 1-in-10 resource adequacy criterion is economically efficient if it calls for an amount of capacity that reasonably balances the incremental costs and benefits of additional capacity. Under this principle, more capacity should be built as long as its incremental cost is no greater than the anticipated incremental benefit.

27. The cost of incremental capacity can be represented by the annualized cost to build and maintain the most economical type of capacity, less the amount of those costs the plant can be expected to offset through sales of energy and ancillary services. Gas-fired combustion turbines are generally considered to represent the cheapest type of generating capacity, and PJM

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[11] See, for instance, Telson, Michael E., *The Economics of Alternative Levels of Reliability for Electric Power Generation Systems*, Bell Journal of Economics Vol. 6 No. 2 (Autumn 1975) p. 679; Cramton, Peter and Steven Stoft, *The Convergence of Market Designs for Adequate Generating Capacity*, April 25, 2006, p. 32; Joskow, Paul L., *Competitive Electricity Markets and Investment in New Generating Capacity*, June 12, 2006, p. 48-49; and Hogan, William W., *Regulation and Electricity Markets: Smart Pricing for Smart Grids*, presentation to the Energy Bar Association Electricity Committee Meeting, October 16, 2009, pp. 21-23.

[12] Wilson, James F., *One Day in Ten Years? Resource Adequacy for the Smart Grid*, November 2009, available at www.wilsonenec.com. The evaluation of the "one day in ten years" criterion is at pp. 9 - 14. Or see Wilson, James F., *Reconsidering Resource Adequacy (Part 1): Has the One-Day-in-Ten-Years Criterion Outlived Its Usefulness?*, Public Utilities Fortnightly, April 2010.

has developed net cost values for such units for its RPM capacity construct, which are in the range of $170 to $320/MW-day, or roughly $60,000 to $120,000/MW-year.[13]

28. The incremental benefit of holding more capacity for reliability results from reducing the frequency of curtailment due to capacity shortages. This potential benefit depends upon the anticipated frequency of such outages (the LOLE) and the cost of outages to the electricity consumers who are curtailed (often called the value of lost load or VOLL). Incremental capacity helps to avoid or reduce curtailment within the geographic area to which the capacity is likely to be incrementally deliverable in peak hours when load loss might occur. Additional capacity also can contribute to lower market prices for energy and ancillary services, potentially an added benefit from the consumer's perspective. However, the last increments of capacity built to satisfy the 1-in-10 criterion (or any criterion leading to a low frequency of outages) will run infrequently. The overall impact on prices of incremental capacity at this level of resource adequacy should be minor unless there are serious market design flaws or substantial unmitigated market power (or, as discussed below, price-responsive demand plays a substantial role in balancing supply and demand in peak periods).

29. For VOLL, average values in the range of $2,000 to $5,000/MWh are the "accepted industry practice", according to a 2006 U.S. Department of Energy report.[14] Some customers have higher VOLLs but are also more likely to self-provide reliability with on-site backup generation or uninterruptible power supply systems; VOLL for this purpose should reflect the average value for the customers most likely to be curtailed and lose service in the event of resource shortage. If a typical outage due to resource adequacy lasts for five hours, for a system that is at 1-in-10, an incremental MW saves 0.1 (expected outage events/year) x 5 (hours/event) x VOLL ($/MWh curtailed), or $1,000 to $2,500/MW-year.

30. This suggests that the incremental cost of capacity, when 1-in-10 is satisfied, is roughly 20 to 100 times greater than the incremental benefit it provides in reducing the frequency of having to curtail firm load (comparing costs in the $60,000 to $100,000/MW-year range to benefits in the $1,000 to $2,500/MW-year range). In my paper on this subject I showed

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[13] PJM, *2013/2014 RPM Base Residual Auction Planning Period Parameters*, Table 5 p. 7, available at: http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx.

[14] U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them*, February 2006, p. 83.

that with an LOLE of 0.1 outages per year (as implied by the 1-in-10 criterion), the incremental cost of capacity exceeds the incremental benefits by a wide margin across a range of reasonable assumptions. Estimates of the cost of capacity and value of service to customers suggest that a balancing of marginal cost and marginal benefit would require targeting a system-level outage frequency substantially greater than 1-in-10.

31. This calculus changes on a system with a large amount of price-responsive demand, as noted earlier and illustrated in Figure 2. Under those circumstances, generating capacity is built to serve a lower fraction of the potential peak load and the marginal generator runs many more hours and earns more revenue. The net cost of capacity is lower, as is the net benefit and "net VOLL", as the alternative to involuntary curtailment becomes service that at times may be at very high prices approaching VOLL. Under these circumstances, it becomes difficult to identify LOLE or the marginal costs and benefits of capacity. Fortunately, it also becomes unnecessary, because under these circumstances a high level of resource adequacy is provided under market forces.

B. The "one day in ten years" reliability criterion also appears excessively stringent from the customers' perspective

32. While "(not more than) one day in 10 years" could be interpreted as a reliability pledge to each and every customer, the 1-in-10 criterion is interpreted as pertaining to the frequency of curtailment or load loss due to resource shortage at the system level. However, when outages due to insufficient resources occur, typically only a small fraction of load must be curtailed to bring the system into balance. Consequently, only a small subset of customers is affected each time an outage occurs, and the frequency with which any individual customer is curtailed will be much lower than the system's outage frequency.

33. The frequency of curtailment due to resource shortage for the typical customer, based on the "one day in ten years" criterion, can be roughly estimated with a few additional assumptions. If the typical outage lasts five hours, during this time an average of 2 percent of a system's firm load is curtailed in each hour, and the curtailment is rotated hourly, then in total 10 percent of the customer load is curtailed for an hour during each outage. If it is further assumed that 50 percent of the customers are, or share circuits with, essential-use customers, and, therefore, are exempt from curtailment, the curtailment must be imposed on the remaining 50 percent of customers. With these assumptions, the exposed customers would be curtailed for one

hour every five outage events on average. Thus, 1-in-10 for a system translates into roughly one hour of outage every 50 years (or 1.2 minutes per year) for the average customer exposed to such outages, under these assumptions.

34. Most electricity customers experience a frequency of outages much higher than this due to disturbances in the electric distribution systems that serve them. A recent report by the Lawrence Berkeley National Laboratory summarized utility-reported SAIDI[15] values by census division, with major events excluded, showing a range from 107 to 212 minutes a year and a national average of 146 minutes a year.[16] Thus, distribution system outages appear to impose roughly two orders of magnitude more minutes of outage on customers than does resource adequacy under the 1-in-10 criterion – i.e., 146 minutes per year compared to 1.2 minutes a year. In addition, distribution system outages, which typically occur unexpectedly and for unpredictable durations, arguably are more disruptive and costly per minute of outage than the rolling blackouts that result from resource shortage.

35. If the 1-in-10 resource adequacy criterion is excessively stringent it leads to excess capacity that imposes unnecessary capacity cost on consumers. In addition, excess capacity will tend to depress energy and ancillary services, with a negative impact on competitive markets. Depressed energy and ancillary services prices will also discourage and delay the development of demand response and price-responsive demand, and foster continued heavy dependence on administrative capacity markets.

36. This discussion calls into question whether the 1-in-10 reliability criterion specified in the Standard's section R1 has led to an efficient level of resource adequacy and whether the criterion is a sound choice to provide a common measure of resource adequacy.

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[15] Utilities summarize the number of minutes of interruption the average customer experiences with the System Average Interruption Duration Index, or SAIDI, usually expressed in minutes of outage per year.

[16] Joseph H. Eto and Kristina Hamachi LaCommare, *Tracking the Reliability of the U.S. Electric Power System: An Assessment of Publicly Available Information Reported to State Public Utility Commissions,* for the Ernest Orlando Lawrence Berkeley National Laboratory, October 2008, p. 15 Table 4. Available at: http://certs.lbl.gov/pdf/lbnl1092e-puc-reliability-data.pdf.

IV. Comments on the Loss of Load Expectation (LOLE) Approach

37. This section comments on details of the LOLE approach called for under the Standard, as it is commonly applied (in particular in PJM) and responds to some of the questions raised in the NOPR.

A. The probabilistic LOLE approach must be applied consistently; highly conservative assumptions are inconsistent with this concept and bias the result

38. Reports documenting applications of the Standard to calculate PRMs show that many judgments and assumptions are adopted in the process of applying the LOLE approach.[17] Such reports show that different Planning Coordinators resolve the many issues differently, reflecting the fact that the Standard describes the required analysis only in very broad terms.

39. In principle, the LOLE approach requires either characterizing all input assumptions and values probabilistically, or, if the uncertainty about a particular value is not large, median, most likely, or mean (expected) values can be used as a reasonable simplification. However, there can be a tendency to adopt very conservative assumptions (that will lead to a higher PRM) rather than most likely or expected values.

40. For instance, assumptions may be adopted based on the view that the PRM calculation should not reflect "reliance" on resources that are not firmly committed to the market area, such as non-firm resources that may be attracted by very high prices during peak periods, or resources located in adjacent regions that may be available during peak periods. While such resources may individually be non-firm, it may be the case that collectively they are highly likely to be available in a substantial quantity. When this is the case, ignoring or understating them results in an inaccurate LOLE calculation, and the calculated PRM may be considerably higher than necessary. The suggestion that the PRM should not be calculated "relying upon" the likely availability of some quantity of non-firm resources loses sight of the goal – to calculate the PRM that satisfies an LOLE equal to 0.1 – and instead applies a concept more appropriate to the construction of a capacity plan.

41. To calculate the PRM that provides an LOLE of 0.1 ("one day in ten years"), the LOLE approach, which calls for probabilistic modeling, must be applied consistently to all data

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[17] See, for instance, *2010 PJM Reserve Requirement Study*, September 30, 2010, or Midwest Independent Transmission System Operator, Inc., *Planning Year 2011 LOLE Study Report*, draft, December 9, 2010.

and assumptions used in the analysis; otherwise, the resulting LOLEs will be inaccurate and the resulting PRMs will be distorted by an unknown amount. For the Standard to be applied in a technically sound manner the LOLE approach and concept should be applied consistently and not be selectively abandoned in favor of conservative values for some assumptions.

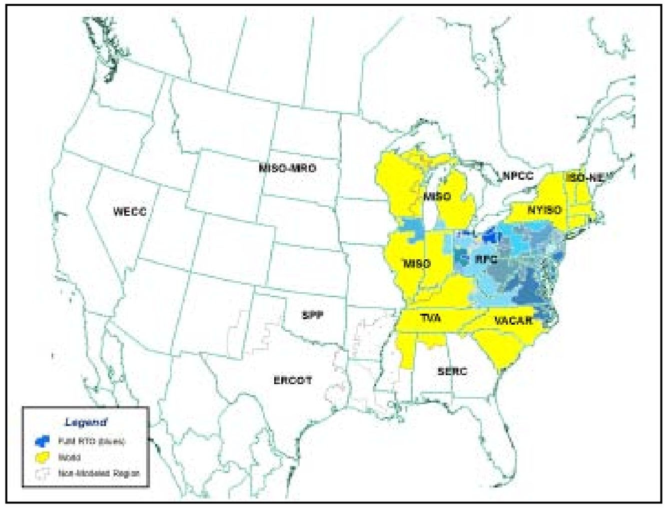
B. Overly conservative assumptions regarding the potential for assistance from adjacent regions lead to building generating capacity that is duplicative of the Eastern Interconnection's transmission capacity

42. The Standard calls for Planning Coordinators to consider and document "the potential assistance from other interconnected systems including multi-area assessment considering transmission limitations into the study area" (R1.3.4) but does not further specify how this is to be done. The NOPR requests comment on whether Capacity Benefit Margin may be used to satisfy the Standard's requirements.

43. Entities calculating PRMs for their footprints adopt various assumptions about the potential assistance that may be available through interconnections with neighboring systems when such help might be needed to avoid a resource shortage (other than firm imports, which are generally treated as firm in-area capacity). Planning Coordinators may be inclined to adopt very conservative assumptions in this regard; for instance, they may understate the transmission interconnections with neighboring systems; ignore or understate the diversity in the timing of neighboring systems' peak loads; understate the likely actual reserve margins of neighboring systems in future periods; or assume that neighboring systems' demand response providers will not have reduced their consumption during peak periods. If Planning Coordinators adopt extremely conservative assumptions regarding the potential assistance from neighboring systems during peak periods, the calculations will show a need for higher PRMs to meet the "one day in ten years" criterion than would result from more realistic (more accurate) assumptions. When this occurs, the presence of, and value of the Eastern Interconnection that surrounds each eastern Planning Coordinator's system is ignored or understated. This leads to planning generating capacity that is essentially duplicative of the capacity afforded by the Eastern Interconnection's transmission grid.

44. In particular, PJM's approach to modeling neighboring systems is highly conservative and understates the potential assistance likely to be available from neighboring regions. In determining its PRM, PJM considers its interconnections with the New York

Independent System Operator ("NYISO"), ISO-New England, MISO, TVA, VACAR and Dominion, as shown in the figure on this page.[18] However, PJM uses a model that is limited to characterizing all of the adjacent systems as a single "world" region. This precludes representing the substantial diversity in the timing of peak loads amongst these systems, which are separated from one another by roughly 1,000 miles.



My review of historical hourly loads for these systems confirms that their peak loads often occur on different days or in different hours than each other or PJM, so it is highly likely that in an hour when PJM is in need of assistance, at least some of these neighbors will not be experiencing extreme peak loads and will have capacity that can be imported into PJM.[19]

45. Furthermore, PJM takes the position that its Reliability Assurance Agreement prohibits it from recognizing, in its PRM calculation, any potential for assistance greater than the approved Capacity Benefit Margin ("CBM") of 3,500 MW.[20] This results in understating the potential assistance available from the various neighboring systems, which at times may be much greater than the CBM.

46. As to the NOPR's question about Capacity Benefit Margin (P 19), the clear answer is Yes, the capacity represented by CBM should be reflected in an LOLE analysis to determine PRM. CBM exists to allow load-serving entities to reduce their generation

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[18] 2010 PJM Reserve Requirements Study, p. 6-7.

[19] Wilson, James F., *Estimate of Historical Help Available From Neighboring Systems*, and *Evaluation of Historical Diversity Between PJM RTO and Coincident "Small World" Peaks*, presentations to PJM Reserve Requirements Assumptions Working Group, May 11, 2009, available at http://www.pjm.com/committees-and-groups/working-groups/rrawg.aspx#23.

[20] PJM's Reliability Assurance Agreement, Schedule 4.C: "The projection of the Forecast Pool Requirement shall consider the following data and forecasts as necessary: … 8. The emergency capacity assistance available as a function of interconnections of the PJM Region with other Control Areas, *as limited by the capacity benefit margin* …" emphasis added.

requirements (this is explicit in the definition[21]), and ignoring it would skew the LOLE and PRM calculations (and result in little or no purpose to reserving any CBM). Indeed, as argued above, all transmission capacity into the study area, and the potential assistance through that transmission capacity, should be reflected.

47. PJM's current approach to modeling the potential assistance from neighboring systems in calculating its PRM is, therefore, greatly simplified and highly conservative, which increases the calculated PRM by an unknown amount. However, this approach has been found compliant with the language of the Standard. This calls into question whether the Standard ensures that a technically sound and reasonably accurate approach is followed. The modeling of potential assistance from neighboring regions should be realistic, consistent with the goal of determining the LOLE corresponding to any PRM, and Capacity Benefit Margin, and additional assistance that very likely will be available, if any, should be modeled.

C. The application of the LOLE approach to very different geographic footprints can lead to very different levels of resource adequacy

48. The Standard calls for each of the Planning Coordinators in the RFC footprint to calculate a PRM (section R1.1). While the geographic scope of the analysis to determine the PRM is not stated, the established practice is for entities performing such analyses to focus on the load and generation within their own footprints (including any out-of-area loads and resources considered part of or served by their systems), with some representation of the potential for assistance from adjacent interconnected systems when needed.

49. In its review of the Standard, NERC recognized that loss of load calculations are footprint-dependent and suggested that this could result in inconsistent levels of reliability.[22] Indeed, one outage due to peak load exceeding available capacity per decade on the PJM system, which serves 51 million people, is not the same as one outage per decade on the much smaller system of the Ohio Valley Electric Corporation ("OVEC"), another of the four Planning

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[21] The NERC definition of Capacity Benefit Margin states in part, "Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections…" Glossary of Terms Used in NERC Reliability Standards, April 20, 2010, p. 9.

[22] RFC responses to NERC's evaluation of the proposed BAL-502-RFC-02 standard, April 17, 2009 (included in the NERC Filing within Exhibit C), p. 3 ("Since LOLE is footprint size dependent, a 0.1 day per year criterion won't equate to consistent reliability for the Planning Coordinators (PCs) that are subject to the standard.")

Coordinators to which the Standard applies. In response to NERC's comments, RFC suggested that "if a study is done properly, including assistance that may be available from adjacent areas, size of footprint should not impact the result."[23] It is true that to the extent the study region and all adjacent regions are realistically modeled the geographic scope of the PRM analysis is less important; however, as noted above, it is common to model adjacent areas very conservatively, understating the potential assistance.

50. As noted above in the discussion of the 1-in-10 criterion, incremental capacity reduces outage risk to consumers over the entire geographic area to which the incremental capacity is likely to be incrementally deliverable during times when a resource shortage could occur. Therefore, balancing marginal cost and marginal benefit might suggest that it would be economically efficient to provide a lower expected frequency of outages due to resource shortages to consumers located in a large unconstrained region than to consumers in a small load pocket. Issues regarding the geographic scope of LOLE studies and the possibility of transmission-constrained sub-regions are further discussed in the next sections of these comments.

51. The extent to which the geographic scope of the analysis results in different levels of reliability in different regions will depend on how realistically adjacent areas are modeled in the analyses, as NERC and RFC recognize, among other differences. Accuracy in the modeling of potential assistance from adjacent areas only partially addresses the potential for disparities.

D. The PRM calculation is performed for the Planning Coordinator's area as a whole and the potential for LOLE due to transmission constraints within sub-areas should not be reflected in the LOLE and PRM calculations

52. Section R1 of the Standard is interpreted by PJM to call for calculating the PRM for the PJM RTO treated as a single unconstrained region, without taking into account the possibility of loss of load due to transmission constraints within sub-areas of the RTO. A later section of the Standard, R2, calls for each Planning Coordinator to "annually document the projected Load and resource capability, for each area or Transmission constrained sub-area

[23] ReliabilityFirst Resource Adequacy Regional Standard, including RFC responses to issues raised in NERC's quality assurance review of standard BAL-502-RFC-02, p. 4, included in the NERC Filing within Exhibit C.

identified in the Resource Adequacy analysis." The Standard does not require calculation of LOLEs or PRMs for any such transmission-constrained sub-areas.

53. While PJM's interpretation of the Standard has been found compliant, some stakeholders have taken the position that the PRM should be calculated reflecting the potential for loss of load in transmission-constrained sub-areas. However, PJM's interpretation is appropriate; to interpret the Standard as requiring calculation of the PRM considering potential LOLE in constrained sub-areas would not be technically sound and would lead to an inefficient resulting PRM value under many circumstances. The next subsection of these comments provides specific examples of how such an approach would be technically unsound.

E. The potential for LOLE in constrained sub-areas should not be understood as "diminishing" compliance with the Standard and requiring that more stringent resource adequacy criteria be imposed on such sub-areas

54. With respect to resource adequacy for transmission-constrained sub-areas, the Standard (section R2) requires reporting but does not require any calculations. Of course, PJM and other RTOs perform analyses to determine the need for transmission enhancements or additional generation in local areas, and each RTO has developed its own methods for these studies. In particular, PJM evaluates sub-area resource adequacy imposing a "one day in 25 years" reliability criterion (LOLE = 0.04). This criterion was recommended by a PJM committee in 1996[24] and is only specified in the PJM manuals, it is not part of any reliability standard or operating agreement. This criterion, more stringent than the standard "one day in ten years" required by the Standard for the PRM calculation, was chosen by PJM in order that sub-area constraints "not appreciably diminish" meeting the "one day in ten years" reliability target at the PJM level. The PJM manuals describe the rationale for the "one day in 25 years" criterion as follows:

> "The Load Deliverability Method requires the selection of a transmission risk level to define the CETO. This risk must be very small when compared to the one day in ten year LOLE applicable to generation risk. A transmission LOLE of 1 D/ 25 Y was judged to be sufficiently small." [25]

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[24] *Subarea Import Capability Loss-of-Load Risk*, Memorandum from Mark J. Kuras, Secretary, Mid Atlantic Area Council Area Coordination Committee to the MAAC Area Coordination Committee, December 10, 1996 (noting there is no applicable industry standard, and providing the rationale for recommending the "one day in 25 years" criterion.)

[25] PJM Manual 20: PJM Resource Adequacy Analysis, p. 32.

> "The Transmission System is tested at a LOLE of 1/25 so that the transmission risk does not appreciably diminish the overall target of a 1/10 LOLE for PJM."[26]

55. Thus, while PJM determines its RTO-wide PRM to satisfy 1-in-10 ignoring such local constraints, it seems to harbor doubts about this practice and whether such constraints and resulting LOLE should be reflected in the RTO-level PRM calculation. Other RTOs' approaches to evaluating sub-region resource adequacy also reflect some linkage to the 1-in-10 goal at the system level.

56. Methodologies for evaluating sub-area resource adequacy are outside the scope of the Standard, and, therefore, arguably not relevant to this proceeding. However, PJM justifies imposing "one day in 25 years" on sub-areas out of concern for potentially "diminish[ing]" the RTO-level goal of "one day in ten years" specified in the Standard. Therefore, it is relevant to note that linking resource adequacy in local areas to adequacy at a broader system level has only an administrative, but not an engineering or economic, justification.

57. To see this, consider a Planning Coordinator region that has three sub-regions that are potentially constrained in peak periods, and, therefore, each has a non-zero LOLE. Suppose further that each of the three region's LOLE is 0.1, and there is some diversity between these areas so that the outages could occur at different times. Then the aggregate LOLE for the RTO, considering the sub-area outage risks and LOLEs, would be greater than 0.1 (probabilistically summing the regional LOLEs plus the RTO-level LOLE). However, note the following.

- No amount of additional capacity in the RTO region outside of the constrained subareas would bring the aggregate RTO LOLE down to 0.1. Only generating capacity located within the constrained areas could lower the combined LOLE to this level. Thus a PRM such that the aggregate LOLE = 0.1 does not exist.
- If, instead, the combined LOLE for the sub-areas is just under 0.1, adding a very large amount of capacity in the RTO region could potentially lower the combined LOLE below 0.1. But this would be highly inefficient, because capacity is more needed and valuable in the sub-areas.
- If the RTO and two sub-areas have a large amount of excess capacity, the third sub-area can be close to LOLE = 0.1 and the RTO would also be close to 0.1 in aggregate. But if two sub-areas are jointly close to LOLE = 0.1 this would seem to require that the third sub-area be well below 0.1 in order to not raise the combined LOLE above

[26] PJM Manual 14B: PJM Region Transmission Planning Process, p. 41.

0.1. There is no economic or engineering logic to such an interdependence between adequacy in the various sub-areas.

- Note further that if each of the sub-areas was a separate Planning Coordinator region, the Standard would allow each to have LOLE = 0.1.

58. PJM's Mid Atlantic sub-area (also called "MAAC") corresponds to the PJM footprint before recent expansions of the RTO. It has a peak load over 60,000 MW, and was planned according to 1-in-10 before the recent expansions. MAAC is roughly the size of the NYISO and ISO New England combined, and is also roughly the size of the ERCOT or California ISO systems. MAAC is also roughly twenty times larger than OVEC, to which "one day in ten years" would also apply as an RFC Planning Coordinator. However, MAAC is now a sub-region of the expanded PJM RTO, so PJM now imposes the "one day in 25 years" reliability criterion on it[27], which exacerbates the enormous disparities in PJM capacity prices (in the most recent auction, $226.15/MW-day inside MAAC, and $27.73/MW-day outside MAAC).

59. For the Standard to lead to a technically sound and efficient approach, transmission constrained sub-areas of a Planning Coordinator's footprint should not be considered in the LOLE and PRM calculations under the Standard's section R1. Nor should R1 be understood as indirectly requiring highly stringent adequacy criteria for potentially constrained sub-areas in order that LOLE due to such constraints "not appreciably diminish" compliance with 1-in-10 at the system level.

F. For the LOLE analysis to be internally consistent and technically sound the characterization of load forecast and other uncertainties should be focused on a one-year-ahead perspective

60. The Standard requires (at R1.2) calculating the PRM for Year One (the planning year that begins with the upcoming peak period), at least one year 2 to 5 years out, and at least one year 6 to 10 years out. To determine the LOLE corresponding to any PRM, and the PRM that satisfies "one day in ten years", the probability of extreme peak loads and of high levels of plant outages must be quantified in the analysis. However, the Standard is not clear about how uncertainties about load and resources years into the future should be characterized in this

[27] A sub-area's actual resource adequacy reflects both the chance of an outage due to constraints into the sub-area and also the LOLE in the surrounding market area, which could also lead to loss of load in the sub-area. However, in the case of PJM and MAAC, the "Rest of RTO" region typically has substantial excess capacity and little chance of resource shortage, which in any case would result in curtailments spread over many consumers.

exercise. As a result, the Standard may be ambiguous and may not prescribe a technically sound approach for years beyond Year One.

61. Uncertainty about peak load over the coming year is much more limited than uncertainty about peak loads years into the future. Uncertainty about this year's peak load mainly results from uncertainty about the extreme weather that will occur. On the PJM system a "90/10" extreme weather summer peak that is expected to occur once every ten years is about five percent higher than the median summer peak that is expected to be exceeded about half the time.[28] Looking out multiple years, peak loads are much more uncertain. Over multiple years, economic growth, changing electricity prices, success in achieving greater energy efficiency and other uncertain forces can have substantial impacts on peak load. The higher level of uncertainty about future peak loads is reflected in NERC's peak demand forecast "bandwidths", which for the RFC region, reflect an 80% confidence interval for peak demand that is +/- 6% one year out, +/- 10.5% three years out, and +/- 16% seven years out.[29] The same phenomenon – greater uncertainty over longer time frames – also characterizes uncertainty about generator performance and outages to some extent.

62. In principle, there are two technically sound and internally consistent ways this reality could be addressed in applying the LOLE approach. The conceptually pure approach would be to attempt to represent the full range of uncertainty about future loads and resources at each point into the future from today's perspective, quantifying the fact that years out, peak load and resources are much more uncertain. However, if this approach is selected, it is also necessary to reflect in the analysis that there are many contingent actions available in the intervening years that can and will be taken to ensure reliability should peak loads trend higher. For instance, should peak loads rise faster than expected, a Planning Coordinator (or load-serving entities) could acquire additional short-lead-time new capacity, contract with retiring generators for additional years of service, or contract available firm capacity located in a neighboring Planning Coordinator area, to note a few such actions. If the wide range of future peak load uncertainty about future years is characterized in the LOLE analysis, but such contingent actions are ignored, the resulting "one in ten" PRM will be much larger than

[28] PJM Load Forecast Report, January 2010, comparing values in Table B-1 (forecast median peak loads) to Table D-1 (summer extreme weather peak loads).

[29] NERC, *Regional and National Peak Demand and Energy Bandwidths 2009-2018*, September 2009, Table 5 p. 14.

necessary. However, representing such contingent actions in the analysis is not generally done and would be quite complex.

63. The more straightforward approach, and the one usually applied, is to focus the characterization of uncertainty on those uncertainties present in the one-year time frame: variability primarily due to the impact of weather on load, and plant outages. This approach can be understood to implicitly recognize that contingent actions are available and will be taken should peak loads trend upward more rapidly than originally expected.

64. In PJM's case, PJM does not reflect uncertainty about regional economic growth in its analysis. While PJM includes a "Forecast Error Factor" to reflect the increased uncertainty associated with forecasts covering a longer horizon, the value is set to reflect only one year of uncertainty. PJM documents this choice as based upon the fact that there are annual "incremental" RPM auctions through which PJM can and will acquire additional capacity closer to each delivery year if it turns out that the PRM used in the three-year-forward RPM auction later appears to have been too low.[30]

65. PJM and the Midwest Independent Transmission System Operation ("MISO", to which the Standard also applies) both focus their analyses on variability due to weather and do not attempt to characterize the full range of uncertainty about peak loads years into the future. With this approach, it is not necessary or appropriate to attempt to represent the longer-term contingent actions in the analysis.

66. The Standard can be read as flexible with regard to this issue, allowing either of the approaches described above. However, it also calls for the analysis to "include" and document use of load forecast uncertainty due to "regional economic forecasts" (R1.3). If the requirement to "include" uncertainty about regional economic forecasts is interpreted as calling for quantifying the full range of uncertainty in the LOLE analysis, and the potential for contingent actions is not reflected, it could substantially raise the "one day in ten years" PRMs for future years, leading to acquisition of capacity that is unlikely to be needed, and billions in unnecessary cost for consumers. Such an analysis would not be technically sound, but it could be considered consistent with the Standard as currently written.

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[30] PJM 2010 Reserve Requirements Study, p. 18.

67. To achieve a technically sound application of the Standard, there must be consistency in the characterization of uncertainty and the modeling of contingent actions available to adjust the PRM and capacity commitments as uncertainty resolves over time. The requirement to "include" variability due to regional economic forecasts should not be understood to require quantification of such uncertainty in the PRM calculation.

68. Related to this issue, the NOPR proposes (P 32) that the Standard eventually be modified to require documentation of a "planning gap", the difference between the amount of resources required to satisfy "one day in ten years", calculated under R1, and the projected resources documented under R2. The NOPR suggests that this would be a useful acknowledgement of the potential risk and allow affected entities time to develop a solution before adverse reliability impacts occur.

69. Graphics comparing projected and required resources or reserve margins are commonly included in long-term reliability assessments prepared by NERC and other entities.[31] However, it could be useful to also include such a comparison as part of the documentation prepared according to the Standard. For this purpose, it could also be useful to characterize the broader range of uncertainty about future peak loads and the capacity needs corresponding to high, median and low long-term forecasts.

G. As peak loads become increasingly price-responsive the LOLE approach will become difficult to apply and less meaningful

70. MISO has in place, and PJM has proposed, "shortage pricing" rules to allow prices to rise to very high levels during operating reserve shortages, with the goal of attracting additional supply and demand reductions under such circumstances to enhance reliability. State and federal policies are encouraging implementation of advanced metering and wholesale and retail pricing approaches that will give more electricity customers the ability and incentive to respond to such price signals. As usually applied, the LOLE approach assumes that the variability of load and of available generation are independent – that is, extreme peak loads are no more or less likely when generation availability is low. However, the development of price-

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[31] See, for instance, NERC, *2010 Long-Term Reliability Assessment*, October 2010, p. 99, Figure RFC-1: Summer Peak Reserve Margin Projections, comparing projected reserves under various assumptions to a 15% reserve margin.

responsive demand will result in strong linkages between actual (net) load levels, prices, operating reserve conditions, and generation availability.

71. When prices can rise to very high levels in order to suppress demand, it becomes both more difficult and less meaningful to model the distinction between voluntary and involuntary curtailment, as required to implement the LOLE approach (which requires predicting involuntary curtailment). With a large amount of price-responsive load, it becomes rather arbitrary to distinguish (involuntary) curtailment of load from price-responsive (voluntary) load reductions due to very high prices in an LOLE analysis. When prices reach very high levels approaching many customers' willingness to pay for service (the value of lost load, or VOLL) many customer are close to indifferent between receiving electric service or being curtailed, so the distinction becomes both arbitrary and also unimportant.

72. A straightforward approach to recognizing price-responsive demand in a LOLE study is to simply reflect the maximum amount of price suppression during peak periods. An estimate of the demand reduction that would occur at prices approaching VOLL is subtracted from the forecast of unrestricted peak load. The analysis proceeds with the flattened peak load pattern that results from this assumption. However, as price-responsive demand develops, it will be very hard to predict the maximum potential for price-driven reductions, and Planning Coordinators are likely to adopt very conservative assumptions in this regard. PJM, for example, does not reflect any price-responsive demand in its PRM calculation for 2014 (despite expectations of substantial price-responsive demand by that time[32]), nor does the PRM calculation reflect any assumption regarding additional non-firm supply that may be attracted by new shortage pricing rules. Such conservative assumptions will lead to excessive PRMs and advance contracting for additional generating capacity that is unlikely to be needed. Excess capacity will also suppress energy and ancillary services prices, further discouraging development of demand response and price-responsive demand, as noted earlier in these comments.

73. As the demand side becomes more actively engaged and more price-responsive, capacity additions can be driven by prices and markets rather than administratively-determined

[32] See, for instance, Statement of Terry Boston, President and CEO, on behalf of the PJM Board of Managers: *Demand Response in the PJM Markets*, June 26, 2009 (stating that PJM expects significant progress in developing price responsive demand within the next three years).

minimum capacity requirements, and administrative approaches to resource adequacy may ultimately become unnecessary, as noted above. Historical approaches to assessing and achieving resource adequacy needs should be allowed to evolve with changing circumstances.

H. The Commission's evaluation of the LOLE approach and "one day in ten years" criterion would benefit from actual data and lessons from past incidents

74. Order 672 called for reliability standards to be "based on actual data and lessons learned from past operating incidents, where appropriate" (P 324). NERC has provided no data regarding past operating incidents involving curtailment due to inadequate capacity resources. To evaluate whether the "one day in ten years" practice is effective and efficient, it would be valuable to know whether entities that have planned their systems on this basis have achieved approximately this target level of reliability. It would also be valuable to know how many MW and MWH have been curtailed in such incidents, which groups of customers have suffered the curtailments, how much lead time they typically received, how long they were curtailed, and estimates of the outage costs. It would also be valuable to know whether utilities typically had time to take actions such as appeals to the public to reduce demand before curtailment occurred. Such data would inform evaluation of the appropriateness of the LOLE approach (which focuses on events but not their duration, magnitude or cost impact) and the 1-in-10 resource adequacy criterion. Such data would also show whether utilities are reasonably accurately achieving 1-in-10, or instead a much higher or lower level of adequacy and cost.

75. Utilities report incidents involving capacity and energy emergencies to NERC. In reviewing such reports, I found that the vast majority of incidents did not result in loss of load, or were caused by transmission or distribution system equipment failures, or were caused by extreme weather such as wind, snow, or hurricanes. Perhaps a dozen incidents occurred over the past decade (to 2009) in which there was a loss of load that could be attributed to capacity shortages, the reliability concern addressed by the Standard. Accurate planning based on 1-in-10 would be expected to result in many more outages of this type during a ten-year period. This suggests that the entities applying this criterion may be doing so in a very conservative manner, and rather than achieving 1-in-10 they are achieving much higher reliability, and at higher cost.

76. The Commission's evaluation of the Standard would benefit from data and analysis regarding past operating incidents resulting from resource shortages, including the type of information mentioned above.