Electric Capacity Markets and Resource Adequacy: Recommendations to Properly Balance Competition and Reliability in RTO and ISO Regions

John P. Perkins, III*

Three regions of the country are facing the near-term inability to provide adequate electricity to over sixty-six million customers.[1] The failure is a lack of resource adequacy; or the inability to meet the aggregate electricity requirements of consumers at all times, accounting for scheduled and unscheduled outages.[2] The purpose of resource adequacy requirements is to ensure that enough capacity is available to meet aggregate customer demands around the clock.[3] Determining the right means, incentives, and penalties to ensure that enough capacity is available has proved a daunting task in geographic areas that have allowed greater competition in electric generation.

Contributing to the complexity of ensuring resource adequacy is the framework for electric power regulation. The electric power industry is subject to a patchwork of state and federal regulations. States regulate intrastate rates, which, for the majority of the country, amounts to state regulation of retail rates to end use customers. On the other hand, the federal government controls wholesale rates in interstate commerce.[4] The intrastate and interstate markets shape and affect each other, which is readily apparent when regulators seek to achieve resource adequacy. Within the states, there divisions as well, from traditionally vertically integrated markets with state-approved utility monopolies in generation and distribution to full competition in generation.[5] Under the old regime, ensuring that there was enough capacity to meet future demand was a simple matter of a vertically-integrated utility forecasting future demand, seeking approval from the state regulator to build new electric generation capacity when needed, and receiving a designated return based on the cost for that capital investment.[6] When generation exceeded needed local demand, utilities could sell power to neighboring utilities under federal government regulation of those rates.[7] In exchange for their monopoly privileges, the utilities were required to provide reliable and adequate service.[8]

** Mr. Perkins received his Master of Laws with Highest Honors in Energy and Environmental Law from The George Washington University Law School in May 2013. He is a former partner at Shults & Brown, LLP in Little Rock, Arkansas. Currently Mr. Perkins is a trial attorney with the Federal Energy Regulatory Commission in the Office of Administrative Litigation. This Article was written while Mr. Perkins was a student at The George Washington University Law School. The opinions and views offered here are those of Mr. Perkins and not necessarily those of the United States, the Federal Energy Regulatory Commission, individual Commissioners, or members of the Commission staff.*

1. *See, e.g.,* ERCOT, Report on the Capacity, Demand, and Reserves in the ERCOT Region 8 (May 2013), *available at* http://www.ercot.com/content/news/presentations/2013/CapacityDemandandReserveReport-May2013.pdf (capacity reserve margins will dip well below targeted reserve margin of 13.75% beginning in the Summer of 2015); California Indep. Sys. Operator Corp., 142 FERC ¶ 61248, at P 3 (2013) (California Independent System Operator anticipates a shortage of 3,500 MW of capacity as early as the end of 2017, and a shortage of 4,600 MW of capacity by 2020); ISO New England, FCM Performance Incentives 1 (2012), *available at* http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/fcm_performance_white_paper.pdf.
   (The non-hydro generating fleet in the Independent System Operator of New England region has failed to deliver over 40% of the capacity they have received payments to provide when called upon during stressed system conditions).
2. N.Y. Indep. System Operator, Comprehensive Reliability Planning Process Manual 26 §5.1 (Nov. 20, 2007), *available at* http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_ Guides/Manuals/Planning/CRPPManual120707.pdf.
3. Clinton A. Vince et al., *What Is Happening and Where in the World of RTOs and ISOs?,* 27 Energy L.J. 65, 84 (2006). The main reasons there must be sufficient capacity to meet customer demands at all times are the inability of the grid to store electric energy in an economic fashion and the inelasticity of electricity demand. *See* Paul L. Joskow, *Capacity Payments in Imperfect Electricity Markets: Need and Design,* 16 Util. Pol'y 159, 160 (2008).
4. Jeffery S. Dennis, *Twenty-Five Years of Electricity Law, Policy, and Regulation: A Look Back,* 25 Nat. Resources & Env't 33, 33 (2010).
5. *See id.* at 33–34.
6. Div. of Energy Mkt. Oversight, FERC, Energy Primer: A Handbook of Energy Market Basics 63 (2012), *available at* http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.
7. Vince et al., *supra* note 3, at 75.
8. *Id.*

This framework incentivized utilities to overbuild electric generation capacity in order to increase the capital investment from which they received a rate of return, and as a result, regulators moved toward allowing greater competition in the generation of electricity.[9] State and federal regulators envisioned that competition in both wholesale and retail electricity markets would yield lower costs to achieve the same service.[10] The federal government's progression toward deregulation of the rates in the wholesale markets has been slow and steady, while the states have taken varied paths toward deregulating retail rates, some abruptly halting their efforts.[11] The result of these divergent efforts is a patchwork of various levels of retail competition in the states alongside the steady move by the federal government to increase competition in wholesale rates.[12] Where states have fully deregulated generation to allow for competition in retail rates, generators and resource providers are no longer under any requirement from state regulators to build generation to meet future demand. In those regions, regional transmission organizations ("RTO") and independent system operators ("ISO"), discussed in detail below, have stepped in to provide resource adequacy requirements for their participants so that generation is built when and where needed.[13] The purpose of these requirements is to ensure that generators, resource providers, and load-serving entities[14] provide enough capacity to meet peak customer demand with a cushion of reserve capacity.[15]

The RTOs and ISOs have struggled in some regions, however, to find the right balance between resource adequacy and competition. For example, New Jersey and Maryland recently enacted policies that attempted to bypass the RTO administering the resource adequacy needs of their region, the PJM Interconnection ("PJM"), by granting new local generation significant subsidies.[16] New Jersey and Maryland justified these policies by claiming that the capacity market in PJM had failed to provide for enough new generation within their states to meet future transmission constrained load.[17] PJM is not alone in facing allegations of inadequate resource adequacy. The California Independent System Operator ("CAISO") region is facing a shortage in "flexible"[18] resources by 2017, and is now evaluating options to address the potential deficiency alongside the Federal Energy Regulatory Commission ("FERC").[19] The Electric Reliability Council of Texas ("ERCOT") region is facing a shortage in resource capacity to meet customer demand by the summer of 2015.[20] Finally, and perhaps most urgently, resource providers in the Independent System Operator of New England ("ISO-NE") region have continually failed to provide capacity when called upon to meet peak demand.[21]

Given these resource adequacy shortfalls, it is a pressing matter to determine which resource adequacy requirements are ensuring sufficient capacity in RTO and ISO regions.[22] This Article will seek to answer this question by first providing a general overview of the progression toward competition in wholesale and retail sales; the wholesale electric markets designed to facilitate that competition; the RTOs and ISOs in which those markets exist; and the mix between states with deregulated retail competition and the traditional vertically-integrated framework within the RTO and ISO geographic areas. This Article will highlight that the level of deregulation and competition in generation within the states affects the type of resource adequacy requirements needed within a region. Second, this Article will analyze resource adequacy mandates, incentives, and penalties used by RTOs and ISOs to achieve resource adequacy. Finally, this Article will examine major alleged deficiencies in resource adequacy in these regions and propose solutions where significant design problems exist. This Article concludes that more robust resource adequacy requirements already utilized in several RTO and ISO regions are effectively balancing resource adequacy with market competition and would ameliorate the majority of current resource adequacy deficiencies that exist.

I. Regional Transmission Organizations, Independent System Operators, and the Wholesale Electricity Markets

For most of the 20th century, states employed a vertically-integrated regulatory model: a monopoly utility received approved rates from their retail end use customers based on

9. Dennis, *supra* note 4.
10. Severin Borenstein & Stephen Holland, *On the Efficiency of Competitive Electricity Markets with Time-Invariant Retail Prices,* 36 Rand J. Econ. 469, 471 (2005).
11. Dennis, *supra* note 4.
12. *Id.*
13. Vince et al., *supra* note 3, at 65–66.
14. A load serving entity is a public utility that delivers electricity to end-users. Conn. Dept. of Pub. Util. Control v. FERC, 569 F.3d 477, 479 (D.C. Cir. 2009).
15. *See* Vince et al., *supra* note 3, at 84
16. *See* Candice Castaneda, *Incentives and Reforms at PJM,* Infrastructure (Fall 2012), *available at* http://www.americanbar.org/publications/*infra*structure/2012_13/fall/incentives_and_reforms_pjm.html (describing New Jersey's Long-Term Capacity Agreement Pilot Program and Maryland's Contract for Differences programs).
17. *Id.*
18. Generally, flexible capacity is able to respond quickly to variable and unpredictable requests to ramp its capacity up or down, typically to accommodate sudden output changes inherent in variable resources such as wind and solar. *See* Flexible Capacity and Local Reliability Resource Retention Amendment at 6, California Independent System Operator Corp., 142 FERC ¶ 61248 (2013) (No. ER13-550-000), *available at* http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleCapacityProcurement.aspx.
19. Cal. Indep. Sys. Operator Corp., 142 FERC ¶ 61248, at 1–2 (2013).
20. Samuel Newell et al., ERCOT Investment Incentives and Resource Adequacy 49–50 (June 1, 2012), *available at* http://www.ercot.com/content/news/presentations/2012/Brattle%20ERCOT%20Resource%20Adequacy%20Review%20-%202012-06-01.pdf.
21. ISO New England, *supra* note 1, at 1–2.
22. Now is a good time to make this assessment. RTO and ISO resource adequacy mechanisms have existed now for several years in multiple geographic areas.

their costs of providing service, so-called "cost-of-service" rates.[23] Included in cost-of-service rates was a set rate of return based in large part on the amount of capital investment the utility had made to build or procure generation to meet future needed capacity, plus a state-mandated reserve margin.[24] As the owner of the entire energy network, the monopoly balanced supply and demand over time to ensure that the amount of energy in the network was sufficient to meet ever-changing customer demands.[25] Customers paid a rate for bundled electricity service that included generation, distribution, and transmission.[26] The utilities received a guaranteed rate of return and in exchange were required to provide reliable service with adequate capacity.[27] The reason for the state-imposed monopoly structure is well documented and will not be analyzed here, except to point out that it was contemplated that the high capital infrastructure costs of the energy sector would yield lower costs if they were limited to one state-mandated monopoly with state regulated control over rates.[28]

For the first 50 years of its existence, the Federal Power Commission[29] and its successor, FERC, regulated wholesale electricity sales to ensure that they were just and reasonable[30] on a similar cost-of-service basis, which also included a reasonable rate of return on the utility's investment.[31] If utilities needed to buy power from a neighboring utility to meet demand or avoid high costs when ensuring adequate reserve margins, utilities would share capacity reserves with adjacent utilities.[32] To facilitate reserve sharing, utilities built major interconnecting transmission lines large enough to deliver power in the case of a major generator outage.[33] Today's bulk power grid began as a way to meet this reserve sharing and wholesale need.[34] This also led to the formation of power pools,[35] the forerunners of today's RTOs and ISOs.[36]

This system allowed for a simple regulatory structure over investment in generation capacity, but the rationale for monopoly generation was undermined by economic events in the 1970s and 1980s. Under the traditional model, utilities "had an incentive to maximize capital investment . . . because under the traditional 'cost plus fair return' approach to setting rates, a larger 'rate base' meant more revenues."[37] Consequently, electric rates increased from the overbuilding of capacity, while at the same time electric demand slowed with the 1970s energy crisis and subsequent recession. Therefore, starting in this time period, "general public concern about high-energy costs and the need for conservation caused federal and state governments to consider alternative solutions."[38] Industry participants preached deregulation as the answer[39] and the federal government and some states began a slow march away from cost-of-service rates toward competitive market-based rates.

A. *The Federal Government Progression to Wholesale Market-Based Rates and the Development of RTOs and ISOs*

The Public Utility Regulatory Policy Act ("PURPA") of 1978 ushered in the new era of electricity market development.[40] PURPA opened the wholesale electricity market to small qualifying facilities ("QF"), which included non-utility cogenerators and renewable power producers.[41] These environmental incentives opened the electricity sector to increased

23. *See* David B. Spence, *Can Law Manage Competitive Energy Markets?,* 93 Cornell L. Rev. 765, 768–69 (2008).
24. *See id.* at 769.
25. *Id.* at 770.
26. *Id.*
27. *Id.* at 769. This is sometimes referred to as the "regulatory compact." Reserve margins typically are set at a level sufficient to cover: planned maintenance; unplanned or forced outages of generating equipment; deratings in the capability of generation resources and demand response resources; system effects due to reasonably anticipated variations in weather; and variations in customer demands or forecast demand uncertainty. *See* Midwest Indep. Transmission Sys. Operator, Resource Adequacy Business Practice Manual §§2, 2-1 (2012), *available at* https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2012/20120202/20120202%20SAWG%20Item%2003%20BPM-011-r9_Resource_Adequacy%20redlined.pdf.
28. Spence, *supra* note 23, at 769.
29. The Federal Power Commission is the predecessor to the Federal Energy Regulatory Commission. *See, e.g.,* Ark. Elec. Co-op. Corp. v. Ark. Pub. Serv. Comm'n, 461 U.S. 375, 378 (1983).
30. The "just and reasonable" standard and FERC's jurisdiction over wholesale sales in interstate commerce is set out in the Federal Power Act of 1935 §201, 16 U.S.C. §824(a) (2000).
31. Jack Casazza & Frank Delea, Understanding Electric Power Systems, An Overview of the Technology, the Marketplace, and Government Regulations 217–18 (2d ed., 2010).
32. Div. of Energy Mkt. Oversight, FERC, *supra* note 6, at 38–39.
33. *Id.*
34. *Id.* at 38.
35. "Power pools are multilateral arrangements with members ceding operational control over their generating units and transmission facilities to a common operator. The operator ran an energy management system that used the unit cost data to optimize on a multilateral basis unit commitment and economic dispatch. PJM began in 1927 for utilities to share their generating resources, forming the world's first power pool. The New York Power Pool was formed in 1966 and the New England Power Pool in 1971 in response to the 1965 Northeast blackout. The Electric Reliability Council of Texas (ERCOT) and the Southwest Power Pool (SPP) formed in 1941 to pool resources for the war effort." *id.* at 40.
36. *Id.* at 38–39.
37. Spence, *supra* note 23, at 770–71.
38. Orange & Rockland Utils., Inc. v. Assessor of the Town of Haverstraw, 824 N.Y.S.2d 769 (N.Y. App. Div. 2006); *see* Casazza & Delea, *supra* note 31, at 217. At the same time, the North American Electrical Reliability Council (NERC) was formed to improve the United States' interconnection and communication between electric power pools or regions as a result of the 1965 Northeast blackout. Div. of Energy Mkt. Oversight, FERC, *supra* note 6, at 39.
39. "It was thought that increased competition would spur efficiencies and innovation, ensure adequate generation supplies, and, most importantly, lower rates to consumers." Susan Kelly & Elise Caplan, *Time for a Day 1.5 Market: A Proposal to Reform RTO-Run Centralized Wholesale Electricity Markets,* 29 Energy L.J. 491, 493–94 (2008).
40. Div. of Energy Mkt. Oversight, FERC, *supra* note 6, at 41; Public Utility Regulatory Policies Act (PURPA), Pub. L. No. 95-617, 92 Stat. 3117 (Nov. 9, 1978).
41. Div. of Energy Mkt. Oversight, FERC, *supra* note 6, at 41; *see also* Freemont-McMoran Res. Partners v. Cnty. of Lake, 16 Cal. Rptr. 2d 428, 429 (Cal. Ct. App. 1993) ("Under [PURPA] and [FERC] rules, utilities are required to purchase electricity from qualifying facilities . . . at a price no greater than the utility's avoided cost (the cost the utility would have incurred by generating the electricity itself)").

competition in the wholesale market.[42] PURPA required utilities to purchase power from QFs at a price set by state public utility commissions.[43]

Subsequently, FERC promoted competition in wholesale electricity markets and has continued to do so over the past 25 years.[44] In the late 1980s and early 1990s, FERC began considering requests by wholesale electric power producers to charge "market-based rates," or rates freely negotiated between buyers and sellers, as opposed to cost-of-service rates.[45] FERC concluded that market-based rates would be "just and reasonable" under the Federal Power Act, and therefore were allowed, "if it found that the entity in question lacked market power (i.e., dominance) in electric generation or transmission, and could not erect barriers to market entry by other competitors."[46] FERC has continued to allow wholesale power producers to charge market-based rates, and has formalized the standards for determining whether a producer possesses market power.[47] These standards include reporting requirements to ensure that the market-based rates charged meet the just and reasonable standard of the Federal Power Act.[48]

FERC later issued Order 888 in 1996, which required public utility companies and investor-owned utilities to provide open access to their transmission facilities to all generators.[49] Specifically, Order No. 888 required all jurisdictional public utilities that own, control, or operate transmission facilities:

> [T]o file open access non-discriminatory transmission tariffs containing, at a minimum, the non-price terms and conditions set forth in the Order, and . . . functionally unbundle wholesale power services. Under functional unbundling, the public utility must: (1) take transmission services under the same tariff of general applicability as do others; (2) state separate rates for wholesale generation, transmission, and ancillary services; and (3) rely on the same electronic information network that its transmission customers rely on to obtain information about its transmission system when buying or selling power."[50]

FERC, in Order No. 888, formulated the concept for ISOs as an organization to hold operational control of transmission facilities to ensure open access.[51] FERC envisioned certain benefits to ISO control of transmission facilities, including regional efficiencies, efficient pricing, and market power mitigation.[52] While not mandating participation in or the formation of ISOs, FERC stated that it would monitor whether functional unbundling was proving inadequate to ensure open access and whether participation and formation of ISOs would be required in the future.[53]

Soon thereafter, FERC issued Order No. 2000 to further implement open access to the transmission system and its goal of promoting more competition in wholesale electric markets.[54] Order No. 2000 developed the concept of an RTO, which added regional scope and other characteristics onto its ISO concept.[55] Specifically, FERC envisioned RTOs to be independent grid-operating organizations of sufficient size and scope, to manage transmission system congestion, and to monitor the wholesale power markets.[56] Of key importance to this discussion, RTOs must have a market monitoring plan to "ensure that there is objective information about the markets that the RTO operates or administers and a vehicle to propose appropriate action regarding any opportunities for efficiency improvement, market design flaws, or market power identified by such information."[57]

Again, Order No. 2000 did not mandate participation in or the formation of RTOs or ISOs.[58] Despite its voluntary nature, however, RTOs and ISOs were developed in several areas of the country, in most instances out of the already formed power pools.[59] These RTOs and ISOs not only independently operate the transmission system within their respective jurisdictions, but also, most germane to this discussion, "develop[ ] markets in which buyers and sellers [can] bid for or offer generation" and "use[ ] the bid-based markets to determine [which generators are economical to dispatch to meet demand]."[60] The wholesale markets within an RTO or ISO jurisdiction typically include a day-ahead energy market for the sale of electricity to meet demand for the next day, a real-time energy market or balancing market for the sale of electricity to meet demand during the day, and capacity markets designed to provide payments to generators and other capacity providers to ensure that they are available to reliably meet peak power demands.[61]

FERC has continued to hone the rules for market-based rates for wholesale sales.[62] While maintaining ultimate regulatory oversight over wholesale electricity sales in interstate commerce, "[i]n areas with organized markets [FERC] has relied significantly on RTOs to provide the market rules, the market monitoring, the transmission terms, and recently the resource planning functions necessary to support a conclu-

42. Div. of Energy Mkt. Oversight, FERC, *supra* note 6, at 41.
43. 16 U.S.C. §824a-3 (2005); *see* Casazza & Delea, *supra* note 31, at 221.
44. *See* Dennis, *supra* note 4, at 33.
45. *Id.* at 36–37.
46. *Id.* (*citing* Heartland Energy Servs., Inc., 68 FERC ¶ 61223 (1994)).
47. *Id.* (*citing* Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, Order No. 697, 72 Fed. Reg. 39904 (July 20, 2007)).
48. *Id.*
49. *See* Orange & Rockland Utils., Inc., 824 N.Y.S.2d 769.
50. Vince et al., *supra* note 3, at 66–67.
51. *Id.* at 67.
52. *Id.*
53. *Id.*
54. Dennis, *supra* note 4, at 36.
55. *See* Michael H. Dworkin & Rachel Aslin Goldwasser, *Ensuring Consideration of the Public Interest in the Governance and Accountability of Regional Transmission Organizations,* 28 Energy L.J. 543, 551–53 (2007).
56. *Regional Transmission Organizations,* Order No. 2000, 65 Fed. Reg. 810 (2000), *order on reh'g,* Order No. 2000-A, 65 Fed. Reg. 12088 (2000), *aff'd sub nom.* Pub. Util. Dist. No. 1 v. FERC, 272 F.3d 607 (D.C. Cir. 2001).
57. Vince et al., *supra* note 3, at 73.
58. Dennis, *supra* note 4, at 36.
59. *See id.* at 37.
60. Div. of Energy Mkt. Oversight, FERC, *supra* note 6, at 41–42.
61. *Id.* at 64.
62. *See, e.g.,* Market-Based Rates for Wholesale Sales of Electric Energy, Capacity, and Ancillary Services by Public Utilities, Order No. 697, 72 Fed. Reg. 72239 (Dec. 20, 2007); Wholesale Competition in Regions With Organized Electric Markets, Order No. 719, 125 FERC ¶ 61071 (2008), FERC, Order No. 719-A, 128 FERC ¶ 61059 (2009); Order No. 719-B, 129 FERC ¶ 61252 (2009).

sion that cost-of-service regulation is not needed to ensure 'just and reasonable' rates and terms that promote the public interest."[63]

Therefore, the federal government has moved from cost-based rates toward market-based rates for wholesale sales, and encouraged the formation of RTOs and ISOs to develop and monitor the wholesale electric markets. Included in RTO and ISO functions is the provision of resource planning and adequacy. Two-thirds of the population of the United States is now served by wholesale electricity markets run by RTOs and ISOs.[64]

B. *State Deregulation of Electric Generation*

After Order No. 888 was issued, many states enacted "retail access" or "retail competition" programs, intended to provide their retail electric consumers with a choice of power providers.[65] To give customers an actual choice, most of these restructuring states deregulated the generation of electricity and allowed retail customers to choose their generation provider, while maintaining regulation over distribution services.[66] This change was also accompanied in some cases with required or incentivized divestiture of generation by the state's former monopoly utility to remove and mitigate any market power which they would possess in generation markets.[67] Thus, customers could choose different generation providers whose rates and resource adequacy requirements were not subject to state regulation. The California energy crisis halted deregulation in many states and caused some states to backtrack, principally California.[68] However, retail choice and state deregulation of generation services has taken a firm hold in numerous states, including Texas,[69] Maryland,[70] Ohio,[71] the District of Columbia,[72] New Jersey,[73] New York,[74] Connecticut,[75] Rhode Island,[76] Massachusetts,[77] New Hampshire,[78] and Maine.[79] Other states took a modified approach to deregulation, allowing for some level of retail choice but also maintaining at least some regulatory control over generation and resource adequacy requirements for load-serving entities. These states include California,[80] Delaware,[81] Illinois,[82] Michigan,[83] and Pennsylvania.[84]

The level of deregulation of retail sales in the states that are members of an RTO or ISO geographic area indicates whether the states or the RTOs and ISOs have the princi-

63. Dworkin & Goldwasser, *supra* note 55, at 546.
64. Div. of Energy Mkt. Oversight, FERC, *supra* note 6, at 63. Since RTOs and ISOs are voluntary, several regions of the country do not participate in RTOs/ISOs. Generally, electricity sales at wholesale falls into two categories: traditional bilateral contracts or through RTO and ISO run wholesale markets. *id.* Traditional wholesale electric markets through bilateral contracts exist primarily in the Southeast, Southwest and Northwest. *id.* "About 40 percent of all retail customers are in traditional wholesale markets where utilities are responsible for system operations and management, and, typically, for providing power to retail consumers. Utilities in these markets are frequently vertically-integrated." *id.*
65. *See* Kelly & Caplan, *supra* note 39, at 493; Vince et al., *supra* note 3, at 70.
66. *See* Spence, *supra* note 23, at 784.
67. *See id.* at 784 n.104, 817; Energy Info. Admin., The Changing Structure of the Electric Power Industry 1999: Mergers and Other Corporate Combinations 41–50 (1999), *available at* http://www.eia.gov/electricity/archive/056299.pdf.
68. *See* Steven Ferrey, *Soft Paths, Hard Choices: Environmental Lessons in the Aftermath of California's Electric Deregulation Debacle,* 23 Va. Envtl. L.J. 251, 338–39 (2004).
69. *See* Tex. Util. Code Ann. §39.001(a), 39.102(a)–(b) (West 2013) (After the deregulation process was completed, the power-generation and retail electric markets would be subject to the "normal forces of competition" and "customer choices," but the transmission-and-distribution utilities would remain regulated by the Commission).
70. Md. Code Ann., Pub. Util. Cos. §7-509(a)(1) (West 2013).
71. Ohio Rev. Code Ann. §§4928.03, 4928.05, 4928.15(A) (West 2013) (electric generation is an unregulated, competitive retail electric service, while electric distribution remains a regulated, noncompetitive service).
72. Electricity generation is no longer regulated except for limited provisions regarding the building of generation within the District or the sale of generation assets. *See* D.C. Code §§34-1502, 34-1519, 34-1516 (2001).
73. N.J. Stat. Ann. §§48:3-52, 48:3-56, 48:3-59 (West 2013) (deregulating electric generation, requiring functional separation of generation assets, and unbundling of rates).
74. The Public Service Commission of the State of New York issued an opinion mandating the restructuring of the electric utility industry within the State, requiring the divestiture by the State's electric utilities of their generating assets, establishing the New York Independent System Operator (NYISO) as successor to the New York Power Pool, and creating competitive retail markets. *In re* Competitive Opportunities Regarding Elec. Serv., Order No. 96-12, 94-E-0952, 1996 WL 293495 (N.Y.P.S.C. May 20, 1996).
75. Conn. Gen. Stat. Ann. §16-244, 16-244e(a)(1), (d), 16-244g(b) (West 2013) (deregulating generation, requiring unbundling of generation functions from transmission and distribution functions, and mandating transfer of generation assets to one or more legally separate corporate affiliates or divestiture of those assets entirely).
76. R.I. Gen. Laws Ann. §39-1-27(a), (e) (2013) (deregulating generation and requiring transfer of generation assets to a separate affiliate).
77. Mass. Gen. Laws Ann. ch. 164, §1A(a), (e) (2013) (deregulating generation).
78. N.H. Rev. Stat. Ann. §374-F:3(III) (2013) ("Generation services should be subject to market competition and minimal economic regulation and at least functionally separated from transmission and distribution services which should remain regulated for the foreseeable future.").
79. Maine deregulated electric generation and required investor owned utilities to divest all of their generation assets. Me. Rev. Stat. Ann. tit. 35-A, §§3202(2), 3204(1) (2013).
80. Initially, California required vertically-integrated utilities to divest a substantial portion of their generation assets to unregulated entities. *See* Order Instituting Rulemaking on Commission's Proposed Policies Governing Restructuring California's Electric Service Industry and Reforming Regulation, 1995 WL 792086, at *49 (C.P.U.C. Dec. 20, 1995); In re Cal. Power Exch. Corp., 245 F.3d 1110, 1114 (9th Cir. 2001); Pub. Utils. Comm'n of State of Cal. v. FERC, 462 F.3d 1027, 1037 (9th Cir. 2006). The California Public Utilities Code was amended in 2005 to give jurisdiction back to the California Public Utilities Commission over investor owned utilities and load serving entities to establish resource adequacy requirements to maintain reliability. Cal. Pub. Util. Code §380 (2004).
81. Delaware allows customer choice but maintains regulatory authority over generation and capacity requirements, including the requirement to formulate integrated resource plans. Del. Code Ann. tit. 26, §§1003(a), 1007 (West 2013).
82. Illinois allows for some retail competition, but generation is still regulated. Ill. Comp. Stat. 5/16-103 (2013).
83. Michigan maintained regulation over generation. Mich. Comp. Laws Ann. §§460.10(2), 460.10f(1)–(6) (West 2013).
84. "In regulating the service of electric generation suppliers, the commission shall impose requirements necessary to ensure that the present quality of service provided by electric utilities does not deteriorate, including assuring that adequate reserve margins of electric supply are maintained. . . ." 66 Pa. Cons. Stat. Ann. §2809(e) (West 2013). For an overview of the level of deregulation in every state, *see*, Status of Electricity Restructuring by State, U.S. Energy Info. Admin. (Sept. 2010), http://www.eia.gov/cneaf/electricity/page/restructuring/restructure_elect.html.

pal burden of ensuring resource adequacy in their respective areas.

Where an RTO or ISO region consists primarily of states that still utilize the traditional vertically-integrated utility model or where states have maintained regulatory control over generation, the states still provide for mandated levels of resource adequacy. The Southwest Power Pool ("SPP") is an example of an RTO region that consists of states that still utilize the vertically-integrated utility model. In this market, SPP provides that its member utilities should have a 12% capacity reserve margin, but SPP has no enforcement authority or backstop procurement mechanism to step in if that reserve margin is not met.[85] Rather, the states have the enforcement authority to set the required reserve margin and the utilities make requests from their respective state regulators for approval to build needed generation to meet those reserve margins and receive guaranteed cost-based rates.[86]

Alternately, where a state has deregulated generation to allow competition in retail sales, the state public utility commissions no longer regulate or control how much reserve capacity must be built by electric generators. In regions that consist of primarily deregulated states, the RTOs and ISOs have stepped in to fill the resource adequacy regulatory gap. Each RTO and ISO takes its own approach to resource adequacy,[87] but generally RTO and ISO incentive and penalty structures now provide the principal motivation to maintain adequate capacity.[88] For example, the RTO or ISO may have a capacity market that provides payments to electric generators to have resources available, but also penalize those generators for failure to have or provide the offered capacity when called upon. The RTO and ISO regions where this situation exists include the New York Independent System Operator ("NYISO"), ISO-NE, and PJM.[89] ERCOT consists of only the deregulated state of Texas, but, as will be discussed in detail, does not currently provide specific penalty and incentive structures to ensure a certain level of resource adequacy.

Finally, to further obfuscate matters, there are RTO and ISO regions that have a mix of state and RTO or ISO authority over resource adequacy requirements. In the CAISO and the Midwest Independent Transmission System Operator ("MISO") regions, the states still have ultimate authority to set resource adequacy requirements over their utilities and have various programs to implement those requirements, but the ISO also has certain primary responsibilities to ensure that resource adequacy is maintained.[90] Those RTO and ISO responsibilities are subject to FERC, not state, approval.[91]

Therefore, where state deregulation of generation has occurred, responsibility for resource adequacy has wholly or partly been transferred to RTOs and ISOs. Those RTOs and ISOs must balance resource adequacy requirements with market competition however. The issue is whether the RTOs and ISOs are living up to the responsibility, or whether the incentives and penalties they are employing to ensure resource adequacy need to be significantly modified.

II. Major Resource Adequacy Concerns in RTO and ISO Regions and Proposed Solutions

Almost uniformly in RTO and ISO regions, payments are made to generators to maintain sufficient capacity to meet peak demand and maintain reserves or to demand response providers to reduce demand when called upon.[92] Penalties are assessed against capacity providers for failure to supply resources or reduce demand as promised, load-serving entities for failure to procure their required reserve requirements, or both.[93] The principal difference in the regions is the mar-

85. Southwest Power Pool: Criteria §§2.1.9, 2.2-2.4 (Jan. 30, 2012), *available at* http://www.spp.org/publications/SPP%20Criteria%20and%20Appendices%20January%202012.pdf. SPP has also facilitated more sharing of excess reserve capacity between its member utilities. *See id.* at §§2.1-2.5, 4.1-4.5.

86. *See* Johannes Pfeifenberger et al., A Comparison of PJM's RPM With Alternative Energy and Capacity Market Designs 50 (Sept. 2009), *available at* http://www.brattle.com/_documents/uploadlibrary/upload807.pdf.

87. At one time, FERC proposed uniform resource adequacy requirements that all RTOs and ISOs would be mandated to follow. FERC issued the following proposed rulemaking:

> The Commission proposes a resource adequacy requirement to ensure adequate electric generating, transmission and demand response infrastructure, the level of which is to be determined on a regional basis. Recognizing that supply planning and retail customer demand response are the states' responsibility, the Commission proposes a resource adequacy requirement intended to complement existing state programs. In particular, the Commission proposes that an RTO or other regional entity must forecast the region's future resource needs, facilitate regional determination of an adequate future level of resources and assess the adequacy of the plans of load-serving entities to meet the regional needs. Each load-serving entity would be required to meet its share of the future regional need through a combination of generation and demand reduction.

Remedying Undue Discrimination Through Open Access Transmission Serv. & Standard Elec. Mkt. Design, 100 FERC ¶ 61138, at 14 (proposed July 31, 2002). FERC backtracked, (*see* Remedying Undue Discrimination Through Open Access Transmission Serv. & Standard Elec. Mkt. Design, 68 Fed. Reg. 24679, 24683 (May 8, 2003) (providing that each region with an RTO or ISO will determine how it will ensure that the region has sufficient resources to meet customers' needs, but the approach to and level of resource adequacy will be decided by the states in the region either through state imposed requirements on utilities serving load within the region, or have RTOs or ISOs operate capacity markets), then dropped the proposal (*see* Remedying Undue Discrimination Through Open Access Transmission Serv. & Standard Elec. Mkt. Design, 112 FERC ¶ 61073 (July 19, 2005)). Many state public utility commissions viewed the resource adequacy proposal, along with others in FERC's standard market design proposal, as an intolerable attempt by FERC to take away from state commissions much of their existing regulatory authority over retail electric service. Gary J. Newell & Ransom E. (Ted) Davis, Understanding Electricity Markets, An Examination of How Electricity Markets Work—and How They Don't (2006).

88. Deregulated states still exert some control over generation indirectly, both in terms of resource adequacy and the generation mix, through their continued regulatory jurisdiction over distribution companies. For example, some deregulated states have mandated that regulated distribution companies purchase a certain amount of their energy from renewable sources, or required default service providers or "providers of last resort" to retail customers to acquire all necessary resources to serve all default customers. *See* 66 Pa. Cons. Stat. Ann. §2807(a) (West 2013); Me. Rev. Stat. Ann. tit. 35-A, §3210-C (2013).

89. Div. of Energy Mkt. Oversight, FERC, *supra* note 6, at 83, 92, 99; *History*, Elec. Reliability Council of Tex., http://www.ercot.com/about/profile/history/ (last visited Sept. 2, 2013).

90. *See e.g.,* Cal. Pub. Util. Comm'n, Resource Adequacy Requirements Program, Rulemaking Proceeding 05-12-013, 2010 WL 2543038, at **6–7 (June 3, 2010).

91. Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000) (codified at 18 C.F.R. §35.34).

92. Div. of Energy Mkt. Oversight, FERC, *supra* note 6, at 80, 91, 96, 103, 107.

93. *See* Vince et al., *supra* note 3, at 112.

ket mechanism for how load-serving entities are required to procure their capacity. In most of these jurisdictions, the ISO or RTO administratively sets the demand for capacity based on expected load with a sufficient reserve margin to achieve resource adequacy. They have all attempted, however, to allow market-based mechanisms to provide the needed supply.[94] Some regions rely on bilateral contracts between resource providers and load-serving entities, while others have created complex capacity auctions.[95]

This Article will examine the major alleged deficiencies in these incentives and penalties to achieve resource adequacy. A general overview of the requirements in the relevant RTO or ISO will be examined, the alleged deficiencies will be discussed, and where substantiated, proposed solutions will be offered.[96]

The development of resource adequacy requirements has been, and continues to be, an evolving process. Complicated mandatory capacity auctions are currently the highest evolutionary mechanism used to provide payments to capacity suppliers.[97] Penalty mechanisms have also evolved over time. How far down the evolutionary path a region needs to go depends in large part on the level of deregulation in the states within the region. In RTO and ISO regions that consist primarily of regulated states that have not introduced competition in generation, further mandatory resource adequacy requirements at the RTO or ISO level are unnecessary. Mechanisms to ensure resource adequacy and reliability are already in place and the policy of those jurisdictions is to ensure resource adequacy, not attempt to decrease prices through competition. The evolution of resource adequacy requirements in deregulated RTO and ISO regions has tended toward more complicated mechanisms. Since a truly competitive market that also provides needed resource adequacy is not attainable at this point, this Article concludes that the regulatory complexity in the capacity markets has been necessary to satisfy the goal of simulating a competitive market in generation to decrease prices for consumers, while also ensuring resource adequacy. Until the time fully competitive markets are able to ensure resource adequacy, the deficiencies that currently exist in several RTO and ISO regions can be effectively solved with the adoption of certain mechanisms already employed in the more robust capacity markets.

A. *California and Its Flexible Resource Shortage*

Currently, there is a dispute between the California Public Utilities Commission and the CAISO over whether there will be a shortage in flexible resources in the near future, and if so, how it should be addressed.

1. The California Public Utilities Commission Has Principal Responsibility for Resource Adequacy

There is no formal capacity market in CAISO,[98] which consists of only the state of California, a state that reasserted regulatory authority over its utilities and load-serving entities' procurement of capacity to ensure resource adequacy.[99] The California Public Utilities Commission has the primary responsibility for ensuring resource adequacy, with CAISO serving only a cooperative and backstop role. The California Public Utilities Commission has established a resource adequacy policy that forecasts peak loads one year in advance and mandates that jurisdictional entities procure sufficient capacity to meet the forecasted load plus a 15% reserve margin.[100] The resource adequacy requirements also contain a local capacity component to require generation where needed in transmission-constrained areas.[101] Jurisdictional entities are first subject to compliance filings with the California Public Utilities Commission to ensure that they have fulfilled their overall and local capacity requirements and are then subject to sanctions from the California Public Utilities Commission for failure to meet them. The entities also receive certain incentives for building needed capacity.[102] Jurisdictional entities' "costs of meeting resource adequacy requirements . . . shall be fully recoverable from those customers on whose behalf the costs are incurred . . . on a fully nonbypassable basis, as determined by the commission."[103] Therefore, the California Public Utilities Commission penalizes jurisdictional entities for failure to procure mandated capacity levels, but provides for the recovery of their costs to comply in rates on a cost-of-service basis.

California statutes also require the California Public Utilities Commission to approve a long-term procurement plan for load-serving entities.[104] Every two years, the Public Utilities Commission holds a Long Term Procurement Plan ("LTPP") proceeding to review and adopt the load-serving entities' ten-year capacity procurement plans.[105] The LTPP proceeding evaluates the utilities' need for generation resources, establishes rules for the procurement of needed resources, and mandates the recovery of the costs of that procurement in rates.[106] If a load-serving entity will experience a shortfall in its capacity procurement within the next ten years, the LTPP provides rules for obtaining that capacity and provides that the costs will be recovered in the utility's retail rates.

94. Div. of Energy Mkt. Oversight, FERC, *supra* note 6, at 80, 86, 91, 96, 103, 107.
95. *Id.* at 96.
96. Not all of the RTO and ISO regions will be discussed; however, only those with near-term major alleged resource adequacy deficiencies.
97. *See, e.g.,* Div. of Energy Mkt. Oversight, FERC, *supra* note 6, at 81–82.

98. CAISO is a California nonprofit public benefit corporation started in 1998 when the state restructured its electric industry. Div. of Energy Mkt. Oversight, FERC, *supra* note 6, at 77.
99. *See* Cal. Pub. Util. Code §380.
100. Cal. Pub. Util. Comm'n, 2010 WL 2543038, at *6.
101. *Id.* at *6–7.
102. *Id.*
103. Cal. Pub. Util. Code §380(g) (West 2013).
104. *See* Cal. Pub. Util. Code §454.5(a) (West 2013).
105. *Long Term Procurement Plan,* Cal. Pub. Util. Comm'n, http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ (last modified May 21, 2012) (discussing proceedings established pursuant to Cal. Pub. Util. Code §454.5(a) (West 2004)).
106. *Id.*

As a complement to the California Public Utility Commission's resource adequacy requirements, the CAISO exercises authority to engage in backstop procurement of resources when it deems necessary.[107] This authority is subject to FERC approval.[108] CAISO also identifies generators that must be available for a particular area due to transmission constraints and enters into "Reliability Must Run" contracts as it deems necessary to provide payments to certain generators needed for resource adequacy reasons to ensure they stay in operation, even if they were intended to be closed because of inefficiency or other reasons.[109]

2. The Flexible Resource Adequacy Shortage in California Is Best Addressed by the California Public Utilities Commission

CAISO and the California Public Utilities Commission disagree on whether a resource adequacy shortage in flexible resources (or resources that can respond quickly to ramp up or ramp down) may occur by 2017. CAISO recently requested expanded backstop authority from FERC to provide out-of-market payments to ensure that flexible generation, scheduled to retire for environmental reasons, would remain operating.[110] The California Public Utilities Commission protested, pointing out several deficiencies in CAISO's plan and stating that the California long-term adequacy planning process was sufficient, and indeed, had ameliorated any deficiency.[111] FERC denied CAISO's request, but commenced a FERC technical conference process to address any deficiency.[112]

Assuming a resource adequacy deficiency exists in flexible resources, the deficiency should be handled through the California Public Utilities Commission's long-term procurement process, given the Public Utilities Commission's continued regulation over resource adequacy requirements within the state. The California Public Utilities Commission maintains authority to establish resource adequacy that forecasts peak load one year in advance and mandates electricity providers to procure sufficient capacity to meet that load.[113] For longer-term resource adequacy deficiencies, the LTPP proceeding is available to the Public Utilities Commission to evaluate a utility's need for capacity resources, establish rules for the procurement of needed resources, and mandate the recovery of those procurement costs in retail rates.[114] CAISO's role in ensuring resource adequacy is essentially for emergency backstop procurement for near-term reliability events.[115]

The LTPP process is capable of mandating the procurement of flexible generation by load-serving entities if needed, passing through any costs to rate payers, and penalizing load-serving entities for failure to procure as directed.[116] CAISO's attempt to enlarge its backstop authority is unnecessary to address a long-term planning issue, one which may not arise until 2017.[117] Where the state maintains jurisdiction over resource adequacy requirements, the need for additional requirements at the RTO or ISO level is significantly reduced. FERC recognized this in a similar situation when it rejected MISO's proposal for a mandatory capacity auction, citing the fact that MISO consists of principally regulated states, rendering further mandatory regulation at the RTO level unnecessary.[118] Where states have maintained regulation over resource adequacy, consumers may pay more for reliability than a competitive market, but resource adequacy has been assured at the state level. FERC should remain mindful of the California Public Utilities Commission's continued jurisdiction over resource adequacy requirements within the state when it evaluates any further CAISO requests for expanded backstop authority. The LTPP process is capable of addressing any long-term resource adequacy needs that may exist in California. The design of the LTPP process, however, could be changed to an annual process, as opposed to bi-annually, to address any dynamic changes in the demand and supply of generation.

B. PJM Interconnection and Its Alleged Failure to Procure Enough Capacity in Transmission Constrained Areas

PJM[119] provides perhaps the most complicated and robust resource adequacy requirement structure in a deregulated RTO or ISO region through its mandatory capacity market. It also provides perhaps the closest alignment between the goals of providing competitive markets and ensuring resource adequacy. Two states within PJM Interconnection, however, have contended that the mandatory capacity auction has failed to provide enough new generation in transmission-constrained areas.

1. PJM Interconnection's Mandatory Capacity Market

PJM has evolved significantly from simple bilateral contracting and singular penalties to meet resource adequacy needs. The primary PJM mechanism designed to ensure resource adequacy is a mandatory wholesale capacity market, termed the Reliability Pricing Model ("RPM"). The RPM consists of an administratively-set demand curve, called the Variable Resource Requirement ("VRR") curve, which sets the amount of demand for capacity within PJM based on pro-

107. Cal. Pub. Util. Comm'n, 2010 WL 2543038, at *17.
108. *Id.*
109. *Id.*
110. Cal. Indep. Sys. Operator Corp., 142 FERC ¶ 61248, at 1, 3 (2013).
111. *Id.* 24, 62.
112. *Id.* 1–2, 69.
113. Res. Adequacy Requirements Program, 2010 WL 2543038, at **15–17.
114. *Id.*
115. *See id.* at *17.
116. *See Long-Term Procurement Plan*, Cal. Pub. Utils. Comm'n, http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ (last modified May 21, 2012).
117. Cal. Indep. Sys. Operator Corp., 142 FERC ¶ 61248, at 1, 3.
118. *See* Midwest Indep. Transmission Sys. Operator, Inc., 139 FERC ¶ 61199, at 40.
119. The PJM region consists of all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia, which are mixed between deregulated and regulated states. *Territory Served,* PJM Interconnection, http://www.pjm.com/about-pjm/who-we-are/territory-served.aspx (last visited Sept. 4, 2013).

jected demand plus a reserve margin.[120] While demand is administratively set, supply is determined in an auction format with generators bidding a price for which they will provide a certain amount of capacity.[121] The ultimate price that generators receive and that load-serving entities must pay, the "clearing price," is determined by the intersection of supply and demand that results from the auction.[122]

The VRR demand curve is set at a price and quantity that attempts to reflect the net cost of new entry[123] and is meant to meet the target reserve margins that satisfy reliability standards, plus one percent.[124] The VRR demand curve is set differently by location ("locational deliverability areas") and the amount of capacity that load-serving entities are required to purchase varies by area.[125] Actual procurement levels can deviate from the target somewhat, however, because the auction is structured to procure higher quantities when offer prices are low and procure lower quantities when offer prices are high.[126]

In setting the VRR demand curve, PJM is responsible for calculating the amount of capacity required to meet the desired level of resource adequacy. Similar to ISO-NE and others, PJM sets the final reserve margin through a stakeholder process and is designed to meet the forecasted peak load required to satisfy a loss of load expectation of, on average, one day every ten years.[127] The factors considered in determining the reserve margin include historical load variability, load forecast error, scheduled maintenance requirements for generating units, forced outage rates of generating units, the capacity benefit of interconnection ties with other regions, load variability due to weather, and outages of generating units.[128]

The capacity market itself utilizes a multi-auction structure: (1) a Base Residual Auction, which is held three years prior to the year in which capacity bidders must provide capacity, commonly referred to as the delivery year; (2) Incremental Auctions conducted after the Base Residual Auction to procure additional resource commitments needed to satisfy potential changes in market dynamics; and (3) the Bilateral Market, which allows resource providers an opportunity to cover any auction commitment shortages, and provides load serving entities the opportunity to purchase any required capacity they are thus far lacking.[129] The Base Residual Auction is conducted on a three-year, forward-looking basis to roughly match the minimum lead time necessary to finance and build new capacity."[130] In addition, qualified new sources can elect to receive capacity payments for an additional two years beyond the delivery year under certain conditions.[131]

Like all capacity markets, if the capacity bidder clears the auction, it is paid regardless of whether its capacity is actually dispatched in the future to meet electricity demand.[132] Generation and other resource providers who receive capacity payments can be penalized, however, if their capacity is unavailable during the delivery year or during peak periods when the reliability value of capacity is the greatest.[133] "The combination of these payments and penalties is designed to ensure that suppliers have the proper incentives to make their resources available to PJM during reliability events."[134] PJM measures and penalizes capacity resource providers for unavailability at multiple times and using multiple metrics. For example, PJM measures and administers penalties for a capacity provider's unavailability on a daily basis regardless of whether a shortage or reliability event occurred[135] and calculates a yearly availability score for monitoring purposes.[136] In addition, PJM measures a capacity provider's availability during the likely peak demand hours in summer and winter and provides payments or penalties to resource providers to the extent that they either exceed or fall short of their expected availability.[137] Other time frame and performance metrics include measuring for both summer and winter capability where shortfalls are assessed failure charges.[138] A peak system compliance check also imposes a penalty charge for a committed resource that is unavailable during peak season for a maintenance outage without PJM approval.[139]

Each load-serving entity that provides electricity to end use customers in any PJM area is assessed a capacity charge equal to their capacity obligation in that area multiplied by the final clearing price applicable to that area.[140] For example, Potomac Electric Power Company's capacity charge will equal their amount of load in their particular deliverability area multiplied by the capacity clearing price in that zone. Load-serving entities may choose to hedge that capacity payment obligation by "directly offering and clearing resources in the auctions or by designating self-supplied resources

120. Div. of Energy Mkt. Oversight, FERC, *supra* note 6, at 103.
121. PPL Energyplus, LLC v. Solomon, 2012 WL 4506528, at *2 (D.N.J. Sept. 28, 2012); PPL Energyplus, LLC v. Nazarian, 2012 WL 4092952, at *1-2 (D. Md. Aug. 3, 2012).
122. *Solomon,* 2012 WL 4506528, at *2.
123. "The value of CONE [the cost of new entry] is the estimated levelized cost that a new entrant needs to recover in power markets—including energy, ancillary service, and the RPM capacity market—in order to recover its investment costs. To date, CONE values have been administratively determined through a study which chose the most efficient and competitive new technology based on its estimated levelized costs." Johannes Pfeifenberger et al., Review of PJM's Reliability Pricing Model (RPM) 10 (2008), *available at* http://www.brattle.com/_documents/uploadlibrary/upload696.pdf.
124. Johannes Pfeifenberger et al., RPM Market Analysis 8–9 (June 30, 2008), *available at* http://www.brattle.com/_documents/uploadlibrary/upload696.pdf.
125. Div. of Energy Mkt. Oversight, FERC, *supra* note 6, at 103.
126. Johannes Pfeifenberger et al., Second Performance Assessment of PJM's Reliability Pricing Model 10 (2011), *available at* http://www.brattle.com/_documents/UploadLibrary/Upload972.pdf.
127. PJM Capacity Mkt. Operations, PJM Manual 18: PJM Capacity Market §2.1 (2013), *available at* http://www.pjm.com/~/media/documents/manuals/m18.ashx.
128. *Id.* §§2.1, 3.1.
129. Res. Adequacy Planning, Manual 20: PJM Resource Adequacy Analysis, Manual 20 §1.1 (2013), *available at* http://www.pjm.com/~/media/documents/manuals/m20.ashx.
130. Pfeifenberger et al., *supra* note 124, at 6.
131. PJM Capacity Mkt. Operations, *supra* note 127., §5.3.3.
132. PPL Energyplus, LLC v. Solomon, 2012 WL 4506528, at *2 (D.N.J. Sept. 28, 2012).
133. Pfeifenberger et al., *supra* note 124, at 11.
134. *Id.*
135. PJM Capacity Mkt., *supra* note 127, §8.2.
136. *Id.* §8.3.
137. *Id.* §8.4.
138. *Id.* §8.4.6.
139. *Id.* §8.4.7.
140. *Id.* §1.2.1.

(resources directly owned or resources contracted for through unit-specific bilateral purchases) as self-scheduled to cover their obligation in the Base Residual Auction."[141] Such action may wholly or partially offset a load-serving entity's capacity payment obligation.[142] As explained by the PJM Manual, a load-serving entity's capacity payment obligation may also be offset through bilateral contracts provided that the capacity purchased through contract is offered and clears the RPM auction or is designated as a self-supply resource.[143]

As can be implied from above, the PJM capacity market contains a locational zone component that increases the price of generation capacity in transmission-constrained areas in an attempt to incentivize more generation in those areas. Areas within PJM with limited ability to import electricity because of transmission constraints are designated as locational deliverability areas.[144] Capacity prices in those areas are designed to exceed the capacity price in the unconstrained parts of PJM.[145] This is accomplished through an adjustment to the clearing price and a separate reliability requirement and demand curve for each constrained area.[146] In addition to the mandatory capacity auction mechanism, PJM has a reliability backstop mechanism to resolve near-term resource adequacy and transmission problems.[147]

2. PJM's Alleged Failure to Procure Enough New Generation in Transmission-Constrained Areas Rings Hollow

Perhaps the most publicized resource adequacy failure is the one alleged to be occurring in PJM. This section will address whether New Jersey and Maryland's stated rationale for gaming the PJM capacity market by providing guaranteed prices to new generation above the RPM capacity clearing price is compelling. New Jersey contends that the current RPM clearing price does not allow for new generation capacity to be built because development costs cannot be recouped under current auction clearing prices.[148] According to New Jersey, this occurs because PJM will not adjust the clearing price to factor in new development construction costs.[149] Since New Jersey is a transmission-constrained area, this alleged failure to provide new local generation will impede resource adequacy in their transmission-congested load pocket in the years to come.[150]

To address this perceived failure for new generation in their transmission-constrained area, the New Jersey legislature enacted the Long-Term Capacity Agreement Pilot Program.[151] The legislation stated that PJM's capacity market had resulted in significant capacity additions in the form of demand response, energy efficiency, and some new peaking facilities, but not large additions of new generation.[152] The statute further provided that state action was necessary because "the construction of new, efficient generation must be fostered by State policy that ensures sufficient generation is available to the region, and thus the users in the State in a timely and orderly manner."[153] In order to foster new generation capacity, the legislation called for a contract between the state utilities and selected generators. The contract would provide certain generators that had won bid requests in New Jersey a guaranteed receipt of payments for new generation capacity above what was to be paid to the generator in the RPM capacity auction.[154] In May, 2012, PJM held an auction in which two such generators cleared the RPM auction and were accepted to receive capacity payments.[155] The New Jersey law provided the selected generators with a guaranteed fixed price substantially above the RPM capacity clearing price.[156]

Similarly, Maryland contends that the PJM capacity market is imposing high costs on local ratepayers but providing little to no new generation in the state.[157] Maryland ordered its distribution companies to issue a request for proposals from generators for new generation capacity.[158] On April 12, 2012, the Maryland Public Service Commission issued an order selecting a generation development company as the winner of the request for proposal and provided the developer with a guaranteed price for energy and capacity delivered into the PJM market regardless of the clearing price fixed by the RPM auction process.[159]

Energy and utility companies have sued on federal preemption grounds to set aside New Jersey and Maryland's attempts to circumvent the PJM capacity auction, contending that FERC has exclusive jurisdiction to regulate wholesale rates.[160] New Jersey and Maryland have countered that

141. *Id.*
142. *Id.* The PJM Capacity Market also contains an alternative method of participation, known as the Fixed Resource Requirement (FRR) Alternative. "The Fixed Resource Requirement Alternative provides a Load Serving Entity (LSE) with the option to submit a FRR Capacity Plan and meet a fixed capacity resource requirement as an alternative to the requirement to participate in the PJM Reliability Pricing Model (RPM), which includes a variable capacity resource requirement." *id.* §1.1.
143. *Id.* §4.6.2.
144. Pfeifenberger et al., *supra* note 124, at 10; PJM Capacity Mkt, *supra* note 127, §2.3.
145. Pfeifenberger et al., *supra* note 124, at 10; PJM Capacity Mkt, *supra* note 127, §2.3.
146. PJM Capacity Mkt., *supra* note 127, at. §2.3.
147. *Id.* §5.9.
148. PPL Energyplus, LLC v. Solomon, 2012 WL 4506528, at **2–3 (D.N.J. Sept. 28, 2012)
149. *Id.* at *3.
150. *Id.*
151. N.J. Stat. Ann. §48:3–98.2(d) (West 2009).
152. *Id.* §48:3–98.2(b).
153. *Id.* §48:3–98.2(d).
154. *Id.* §48:3–98.3. Under the Long-Term Capacity Agreement Pilot Program, a winning bidder will be paid (or required to pay) based on the difference between its bid prices for energy and capacity and PJM's corresponding price for capacity. *id.* This assures that the winning bidder will always be paid the greater of (1) the PJM price, or (2) the bidder's winning bid price. *id.*
155. *Solomon,* 2012 WL 4506528, at *4.
156. *Id.**
157. PPL Energyplus, LLC v. Nazarian, 2012 WL 4092952, at *1-3 (D. Md. Aug. 3, 2012).
158. Md. Pub. Serv. Comm'n, Request for Proposals for Generation Capacity Resources Under Long-Term Contract (2011), *available at* http://webapp.psc.state.md.us/Intranet/procurements/RFP/RFP09292011.pdf; *Maryland Utilities Issue Request for Proposals for Generation Capacity Resources Under Long-Term Contract,* PEPCO (Oct. 7, 2011), http://www.pepco.com/welcome/news/releases/archives/2011/article.aspx?cid=1875.
159. *Nazarian,* 2012 WL 4092952, at *2.
160. *See id.* at *4; *Solomon,* 2012 WL 4506528, at *6 (D.N.J. Sept. 28, 2012).

the Federal Power Act gives them the exclusive jurisdiction to regulate "the generation of electric energy."[161] Aside from the preemption issue, the major issue raised by these state efforts is whether the states are right, i.e. whether there is a design flaw in PJM's mandatory capacity auction that prevents needed generation from being built in transmission-constrained areas.

Data suggest that PJM's design components that add a premium to designated transmission-constrained areas are working. The total amount of capacity offered in the region as a whole has increased substantially since the inception of the capacity market.[162] More importantly, the capacity market has attracted and retained sufficient capacity to maintain the desired resource adequacy level in the RTO region overall and in every zone since the three-year forward auction was established.[163] When viewed at a regional level, PJM procurement levels have exceeded the reserve margin target in every one of the first eight base residual auctions by 1.2–4.7%.[164] The RTO-wide surplus dropped between the introduction of the current Reliability Pricing Model in the 2007–2008 delivery year and the 2010–2011 delivery year, but then increased again starting in the 2011–2012 delivery year.[165]

At the locational deliverability area level, capacity resources were slightly below the targeted reserve margin during the first few delivery years of the capacity auction in some areas, but since the Base Residual Auction began procuring resources on a full three-year forward basis, all locational deliverability areas have obtained capacity supplies in excess of their reserve margin targets.[166] The early reserve margin deficits reflected the relatively tighter eastern PJM supply conditions that existed at the inception of the three-year forward mandatory capacity auction, which motivated the need for a locational capacity market in the first place.[167] In addition, all locational deliverability areas have had a significant amount of capacity offered from new generation resources that failed to clear the RPM auction, suggesting both that new generation is simply uncompetitive at this time, but, if needed to ensure reliability, could be procured at higher prices.[168]

The reserve margin targets have been met by a combination of entry by new generation, demand response resources that agree to curtail demand when called upon, upgrades to existing capacity, deferred retirements of existing generating units, planned transmission upgrades, and decreased demand from the economic slowdown.[169] Competition from other capacity providers is the primary reason there has not been more new generation in the eastern PJM region. New generation is not cost-competitive with other options, which suggests the RPM market and its locational deliverability penalties and incentives are working to maintain the desired level of resource adequacy, while also allowing competition in the generation market to reduce costs for consumers.[170] Therefore, New Jersey and Maryland's stated rationale for gaming the PJM capacity market by providing guaranteed prices above the RPM capacity clearing price is not compelling. The PJM capacity market is properly balancing competition in generation while meeting targeted resource adequacy levels, even in transmission-constrained areas.

C. Capacity Providers in ISO New England Have Failed to Provide Resources When Called Upon

ISO-NE[171] has a clear resource adequacy problem. During the last several years, the generating fleet in ISO-NE has failed to respond to requests to provide resources during times of high system stress in the amount of capacity that they were paid to provide in the capacity auction market.[172] Specifically, an examination of dispatch response performance following the thirty-six largest system contingency events over the last three years indicated that, on average, New England's non-hydroelectric generating fleet delivered less than 60% of the power requested of these resources by the ISO.[173] "In sum, at times of greatest need, many resources are delivering far below the performance ability represented in their supply offers."[174] These shortcomings manifested in several operational events that resulted in reliability violations.[175] ISO-NE currently manages high system stress situations by making payments outside the capacity auction to inefficient and relatively expensive oil- and coal-fired plants to operate.[176] For example, ISO-NE was granted a request by FERC for a Winter Reliability Program for the winter of 2013–2014 to procure substantial amounts of oil-fired generation, dual oil- and natural gas-fired generation, and demand response capacity outside the capacity market structure to solve its problem with resource nonperformance during stressed system conditions.[177] ISO-NE expects to have to implement a Winter Reliability Program in some form through the next three winters.[178] Exacerbating the inefficiency in making payments to these generators outside the capacity auction structure is that these resources are at risk of closure due to environmental regulations.[179]

ISO-NE has identified several sources of the problem, including the region's growing dependence on natural gas-

161. *See* 16 U.S.C. §824(b)(1).
162. Pfeifenberger, et al., *supra* note 126 at 16.
163. *Id.* at ii–iii.
164. *Id.* at 10.
165. *Id.*
166. *Id.* at ii–iii.
167. *Id.* at 10.
168. *Id.* at iii.
169. *Id.* at 59.
170. *Id.*
171. ISO-NE includes Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and Maine, all of which have deregulated generation except Vermont. *See Key Facts,* ISO New England, http://www.iso-ne.com/nwsiss/grid_mkts/key_facts/index.html (last visited Sept. 4, 2013).
172. ISO New England, *supra* note 1, at 1.
173. *Id.* at 2.
174. ISO New England, 2013 Regional Electricity Outlook 16 (2013), *available at* http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/2013_reo.pdf.
175. *Id.* at 2. Operational events occurred on June 24, 2010, September 2, 2010, and January 24, 2011, including a North American Electric Reliability Corporation (NERC) violation related to inadequate generation contingency response on September 2, 2011. *id.*
176. ISO New England, *supra* note 1, at 16.
177. ISO New England, Inc., 144 FERC ¶ 61204, at 2, 21 (2013).
178. *Id.* at 40.
179. *Id.*

fired generation, suppliers' reliance on interruptible gas supply agreements, and the resulting failure to produce electricity when natural gas pipeline transportation is constrained.[180] These challenges could be resolved if capacity providers were incentivized to make the necessary operational changes, such as investing in firm natural gas transportation rights or natural gas and oil switching capabilities, but in the words of one comment, "the present [forward capacity market] design provides little incentive for suppliers to undertake these investments."[181]

ISO-NE has proposed several adjustments to its forward capacity market to ameliorate this problem. Therefore, a review of its current resource adequacy requirements, its capacity auction mechanism, and its proposals for change is necessary.

1. ISO-NE's Mandatory Capacity Auction and Reliability Backstops

ISO-NE has also removed bilateral contracts and penalties against load-serving entities alone as the means to procure capacity resources and replaced them with a complex mandatory forward capacity auction. The auction is designed principally to achieve transparency in the price of capacity and to incentivize the development of sufficient resources to meet demand plus a reserve margin.[182] Similar to PJM, ISO-NE operates on a three-year forward basis with an administratively-set level of demand, termed the Installed Capacity Requirement ("ICR"), which includes a reserve margin.[183] Similar to PJM, supply is set through a competitive bidding process, but functions somewhat differently than PJM's RPM. In the annual forward capacity auction, capacity providers offer capacity three years in advance of the delivery year[184] and winning bids are determined as part of a "descending clock auction."[185] Capacity providers bid an amount of capacity they are willing to provide at a price set by ISO-NE.[186] If the amount of capacity offered exceeds the ICR demand requirement, ISO-NE raises the price and solicits bids again.[187] The process ends when the amount of capacity offered equals the ICR demand requirement.[188] The price when this equilibrium is reached is the clearing price.[189][190]

The ICR is an ISO-NE projected measure of the capacity that is necessary to satisfy the area's forecasted peak load with a reserve margin.[191] The ICR is set through stakeholder and state regulator processes and includes a reserve margin that is calculated to meet an expected loss of load, on average, of no more than once every ten years.[192] This loss of load expectation takes into account potential levels of peak load due to weather variations and other variables.[193] In addition, the level of the ICR is determined on a zone basis to incentivize generation and other capacity in transmission-constrained areas.[194]

The three-year forward lead time of the auction "is intended to encourage participation by new resourc[e] [providers] and allow the market to adapt to resources leaving the market."[195] In addition, new resources can elect to have their capacity provision commitment and the capacity clearing price for a specific auction apply for up to four additional years.[196]

In order to participate in the competitive auction, capacity resources must first complete a qualification process demonstrating their ability to provide capacity for their proposed megawatt amount and location.[197] If a capacity provider's bid is accepted, they are then committed to provide the amount of capacity offered in their bids and they must offer it in ISO-NE's day-ahead and real-time energy market.[198] However, ISO-NE only has the authority to assess penalties against capacity bidders that have cleared the capacity price if they are unable to meet their capacity commitment wholly or partially during Shortage Events.[199] A Shortage Event is defined as a system-wide or locational deficiency in resources for 30 or more minutes.[200]

Payments to capacity bidders that clear the market price come from load-serving entities. The ISO assigns each load-serving entity a capacity requirement for each month based on its share of the peak load of the system as a whole and its share in each zone.[201] Load-serving entities are assessed a capacity load charge based on their capacity requirement.[202] A load-serving entity is charged the total of its capacity load obligation in the particular capacity zone multiplied by the net clearing price in the capacity auction.[203] Self-supplied resources are treated as a credit toward the load-serving entities' capacity load obligation and are subject to the same availability penalties as other capacity resources.[204] Bilateral

180. *Id.* at 1; *see also* ISO New England, *supra* note 1, at 12.
181. ISO New England, *supra* note 1, at 1.
182. ISO New England, Market Rule 1, Standard Market Design §III.13, *available at* http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_13-14.pdf.
183. *Id.*
184. Div. of Energy Mkt. Oversight, FERC, *supra* note 6, at 86.
185. Conn. Dept. of Pub. Util. Control, 569 F.3d at 480.
186. *Id.*; *see also* ISO New England, *supra* note 182, §III.13.2.
187. Conn. Dept. of Pub. Util. Control, 569 F.3d at 480; *see also* ISO New England, *supra* note 182, §III.13.2.
188. Conn. Dept. of Pub. Util. Control, 569 F.3d at 480; *see also* ISO New England, *supra* note 182, §III.13.2.
189. Conn. Dept. of Pub. Util. Control, 569 F.3d at 480; *see also* ISO New England, *supra* note 182, §III.13.2.
190. Conn. Dept. of Pub. Util. Control, 569 F.3d at 480; *see also* ISO New England, *supra* note 182, §III.13.2.
191. ISO New England, ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit for the 2016/17 Capability Year 8 (Jan. 2013), *available at* http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/2013/icr_2016_2017_report_final.pdf.
192. *Id.* at 1–2, 8; *see also* ISO New England, *supra* note 182, §III.12.1.
193. ISO New England, *supra* note 191.
194. ISO New England, *supra* note 182, §III.12.2.
195. Div. of Energy Mkt. Oversight, FERC, *supra* note 6, at 86.
196. ISO New England, *supra* note 182, §III.13.1.1.2.2.4. This option is only available if their offer clears the capacity auction.
197. ISO New England, *supra* note 182, §III.13.
198. *See* New England Power Generators Assoc., Inc. 144 FERC ¶ 61157, at P 18 (2013).
199. ISO New England, *supra* note 182, §§III.13.7.2.7.1.2, III.13.7.2.7.1.3.
200. *Id.* §III.13.7.1.1.1(a).
201. ISO New England, *supra* note 182, §III.13.7.3.1.
202. *See id.* §III.13.7.3.4.
203. *Id.* §III.13.7.3.
204. *Id.* §§III.13.7.3.1.2, III.13.7.1.6.

contracting between resource providers and load-serving entities in the traditional sense does not meet a load-serving entity or capacity supplier's obligations in the ISO-NE capacity market. Capacity resource providers are able to contract to sell their supply obligations to a different resource provider and load-serving entities can sell their load procurement obligations to other load-serving entities through bilateral contracts, subject to ISO-NE approval.[205] Otherwise, market participant obligations must be offered and procured in the forward capacity auction.[206]

ISO-NE also has the ability to issue requests for proposal and enter into supply contracts with capacity providers to address a near-term resource adequacy deficiency. If the ISO determines that a region may face a near-term reliability problem from a lack of capacity, the ISO can issue a request for proposals and enter into contracts with capacity providers outside the capacity auction to ensure they are available.[207] The costs for any such contract are charged to market participants in proportion to their regional load within the affected region.[208]

2. More Robust Penalty and Incentive Structures Are Needed in ISO-NE to Ensure Resource Adequacy

ISO-NE has proposed several long-term solutions to ameliorate its capacity supplier non-performance issue. ISO-NE has proposed to slightly shorten the trigger of a Shortage Event and thus broaden the instances when it can levy penalties.[209] The main adjustment ISO-NE proposed, however, is a revised payment and penalty structure for resource performance during Shortage Events. ISO-NE proposes to modify the forward capacity market design to make each resource's revenue contingent, in part, upon its actual performance during Shortage Events.[210] The new performance incentive design will result in transfers from under-performing to over-performing resources:

> During scarcity conditions, some resources are likely to over-perform and reduce the severity of reserve or energy deficiencies due to others' under-performance. In doing so, the total performance payments charged to resources that under-perform are used to compensate the resources that over-perform during the scarcity condition. Effectively, the [forward capacity market] performance incentives amount to financial transfers from under-performing to over-performing capacity resources during the times when additional resources are needed to maintain system reliability.[211]

Therefore, a resource provider will receive a base payment and a performance adjustment, either up or down, under ISO-NE's proposal. The point of this system is to increase the risk and reward for capacity resource performance and motivate suppliers to take actions to improve the physical performance of their capacity resources.[212] Of course, the costs to provide more reliable service will be seen in the capacity auction bids in future auctions.[213] ISO-NE anticipates that these rule changes will take effect in the 2018–2019 delivery year.[214]

These changes are not likely to go far enough, however, because they only apply in Shortage Events, which will only be redefined to include slightly more instances of system stress. This is particularly apparent from the fact that the current Shortage Event penalties have never been triggered.[215] While FERC recently clarified that the failure of a capacity provider to offer the amount of their accepted capacity in the day-ahead and real-time energy market is a violation of ISO-NE's tariff, subject to referral to FERC's Office of Enforcement, this only applies if the fuel source for the generator, such as natural gas, is physically available.[216] Given that one of the major sources of the capacity provider performance problem is the inability to procure stable natural gas transportation service, it is unlikely that this clarification will incentivize generators to comply with their capacity obligations. The problem is unlikely to change until the monitoring, penalty, and incentive structures are expanded beyond narrowly defined Shortage Events. The size of the problem also indicates that major, fundamental change is necessary. Capacity providers have been able to supply only about 60% of the power they were committed to provide in their capacity bids when called upon during system stress.[217]

Similar to PJM, ISO-NE most likely needs to expand the scope of the assessment of capacity resource providers to monitor general availability. Availability could be monitored, penalized, and incentivized on a daily[218] and yearly basis,[219] as well as during likely peak demand hours in the summer and winter.[220] Without enhanced monitoring, New England electric customers will not know if they are getting the resource adequacy and reserve margins they are paying to obtain. Instead, they are likely to pay for a significant portion of their resource adequacy twice: once through the capacity market and then again through ISO-NE's emergency reliability procurement mechanisms, including the Winter Reli-

205. ISO New England, *supra* note 182, §III.3.5. *See Capacity Markets: Where and What Are They?*, Direct Energy Business, http://www.directenergybusiness.com/energy-insights/capacity-markets.php (last visited July 12, 2013).
206. ISO New England Inc., ISO New England Manual for Forward Reserve §1.1 (2013).
207. ISO New England, *supra* note 182, §III.11.1(a)–(b).
208. *Id.* §III.11.1(c).
209. ISO New England, *supra* note 174, at 19; *see also* ISO New England, Interdependencies of Market and Operational Changes to Address Resource Performance and Gas Dependency §3 (2013), *available at* http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/interdependency_of_iso_proposals_to_key_spi_risks-2.pdf. (Shortage Event would change to when the system is experiencing a deficiency in total reserves for thirty or more minutes, as opposed to the current trigger of when ten-minute reserves are short for 30 minutes).
210. ISO New England, *supra* note 1, at 1.
211. *Id.* at 17.
212. *Id.* at 3–4.
213. *Id.*
214. ISO New England, *supra* note 174, at 21.
215. *See* New England Power Generators Assoc., Inc., 144 FERC ¶ 61157 at 58.
216. *Id.* at 47, 56–58, 61.
217. ISO New England, *supra* note 1, at 1.
218. *See* PJM Capacity Mkt., *supra* note 127, §8.2.
219. *See id.* §8.3.
220. *See id.* §8.4.

ability Program. This in essence renders a significant portion of the current auction payments to capacity providers as a simple revenue stream.

More robust penalty and incentive structures for capacity suppliers will not directly solve the natural gas pipeline constraints in New England or the natural gas and electric coordination issues. However, capacity providers will likely develop solutions if they are adequately incentivized to honor their capacity bids and the costs for those solutions can be included in the capacity market. This would provide a more efficient solution than paying for resource adequacy once in the capacity market and then paying for a substantial portion again every year in emergency backstop procurement. This would also more effectively balance competition in generation with the need for resource adequacy by avoiding out of market payments to inefficient generators to maintain reliability. ISO-NE's current proposals may solve some of the capacity availability problems, but more robust monitoring, penalty, and incentive structures under multiple time frames similar to PJM's design structure must be implemented before ISO-NE achieves a competitive market while also ensuring resource adequacy.

D. The Electric Reliability Council of Texas' Energy-Only Market Will Be Unable to Provide Sufficient Resource Adequacy for the Foreseeable Future

ERCOT's attempt to allow competition and market forces to solely determine the amount of capacity that will be available in Texas will not result in sustainable levels of resource adequacy for the foreseeable future. For the time being, Texas' energy-only market is unable to incentivize enough capacity to be built above peak demand to avoid major electricity service curtailments.

1. ERCOT's Energy-Only Market

ERCOT, which administers the electric market for the majority of the deregulated state of Texas,[221] is unique in that it has no mandated resource adequacy requirements and no capacity market. Instead, it relies on high energy price caps to allow for high returns when seldom used generation is needed to meet peak customer demand.[222] Energy generators only receive compensation when they sell their produced energy in the energy market; they do not receive capacity payments for providing a set reserve margin.[223] The market establishes both the supply of and demand for energy resources, including any reserve capacity that will, or will not, be built to meet the highest levels of demand. ERCOT is also unique in that its rates for wholesale transactions are not regulated by FERC because Texas is not interconnected with the rest of the nation's grid.[224] The Public Utility Commission of Texas instead regulates both wholesale and retail sales of electricity within ERCOT.[225]

Between 1996 and 2002, the Texas legislature and the Public Utility Commission of Texas restructured their electricity system to create competitive wholesale and retail markets, and established an energy-only market for generation in the ERCOT region.[226] In an energy-only market, there are no administratively set amounts of capacity that utilities or load-serving entities must obtain; instead the level of capacity and any reserve margin that exists above demand is solely a product of competitive market forces.[227] ERCOT was tasked by the Texas legislature to ensure the reliability and adequacy of the regional electrical network and to monitor the adequacy of resources to meet demand.[228] ERCOT has a target reserve margin of 13.75%, but ERCOT has no authority to enforce that reserve margin.[229] Since the reserve margin is based solely on wholesale energy prices, if any reserve margin is to be obtained, wholesale prices must spike during times of high peak demand to adequately incentivize capacity to be built.[230]

The ERCOT energy market is not completely deregulated, however. Consumers are sensitive to the severe price spikes that would occur in a completely deregulated energy market and a price cap on the wholesale energy price is used to prevent runaway energy prices.[231] "Some energy only markets attempt to set the price cap at the value of lost load (VOLL)," or the price that customers are willing to pay to avoid curtailment of electric service.[232] The theoretical perceived benefit to high price spikes capped at the VOLL is that needed capacity reserves are set at the most efficient price, i.e. the price that customers are willing to pay to avoid curtailment as opposed to administratively-set prices that may be too high or too low.[233] Therefore, energy-only markets "periodically produce much higher prices than those markets with resource adequacy requirements such as PJM and ISO-NE."[234]

ERCOT does not, however, base its price cap on the value of lost load.[235] In the recent past, ERCOT set a $3,000 MW/hr cap by which generators could offer to sell electricity.[236] In the face of an impending resource shortage, the Public Utility Commission of Texas, through an administrative order,

221. ERCOT serves 85% of the electrical load within the State of Texas. Vince, *supra* note 3, at 83–84.
222. Samuel Newell et al., ERCOT Investment Incentives and Resource Adequacy 11 (2012), *available at* http://www.ercot.com/content/news/presentations/2012/Brattle%20ERCOT%20Resource%20Adequacy%20Review%20-%202012-06-01.pdf.
223. *Id.*
224. Vince et al., *supra* note 3, at 84.
225. *See e.g.,* Dynegy Power Mktg., Inc., 111 FERC ¶ 61411, at P 13 (2005).
226. Newell et al., *supra* note 222, at 11.
227. *Id.* at 11.
228. Tex. Pub. Util. Code Ann. §11.002 (West 1997).
229. *Id.*
230. *Id.*
231. ERCOT also maintains two non-market backstop reliability mechanisms that support resource adequacy. One is the Emergency Response Service, "in which approximately 350 MW of medium-large commercial and industrial customers [ ] earn a capacity payment to be callable as a last resort during system emergencies." Newell et al., *supra* note 222, at 13. The other non-market reliability mechanism is ERCOT's option to sign "Reliability Must Run" contracts to induce retired or retiring generation to reactivate or remain online. *id.*
232. *Id.* at 12.
233. *Id.*
234. *Id.*
235. *Id.* (ERCOT does not currently base its $3,000 offer cap on a VOLL estimate but has historically maintained a higher price cap than other non-energy only markets).
236. *Id.*

raised the offer cap incrementally from $4,500 MW/hr on August 1, 2012, to $5,000 MW/hr in June 2013, $7,000 MW/hr in June 2014, and $9,000 MW/hr in June 2015.[237] However, none of these values are necessarily the value of lost load and will not result in an estimated capacity reserve margin of 13.75% or one that results in a loss of load expectation of once every ten years.[238] As reserve margins dip below 13.75%, the probability of significant reliability events substantially increases, including the possibility of major electricity service curtailment.[239]

2. An Energy-Only Market Is Currently Unable to Provide Sufficient Resource Adequacy

ERCOT is facing a near-term resource adequacy shortage and the solution is not a simple one. ERCOT's current energy-only market has failed to achieve resource adequacy at reserve margins necessary to ensure reliability. Recent projections are that reserve margins will dip well below 13.75% by the summer of 2015 and continue downward thereafter.[240] The prospect of declining reserve margins is set against a recent history of electricity service curtailments that occurred after resources encountered unforeseen closures. In February 2011, very cold weather disabled generation and froze some gas delivery equipment, leading to 8 hours of load shedding.[241] Hot weather in August 2011 also pushed the system into shortages that required emergency actions.[242] "These events occurred when the planning reserve margin was 14%, which suggests vulnerability if the reserve margin were to fall to the much lower projected levels."[243] The Public Utility Commission of Texas has responded by moving closer to a true energy-only market by allowing the offer cap to rise.[244] As discussed, the offer cap is being raised in a phased manner to $9,000 MW/hr by June 2015.[245]

Even with high or nonexistent price caps, the energy-only market faces a fundamental design flaw that cannot be corrected in the near future. The principal problems with Texas' move toward a pure energy-only market are the practical realities of the electricity market. In an energy-only market, prices must spike periodically to provide revenue and incentivize generation to be built to meet those higher levels of demand. In an energy-only market there are no other revenue streams for generators except for the sale of electricity. But even the extremely high price spikes that will be allowed in Texas will not incentivize enough generation to be built to avoid major electricity curtailments. The Public Utility Commission of Texas concedes that a $9,000 MW/hr price cap will result in an estimated reserve margin of only approximately 10%, well below a loss of load expectation of once every 10 years.[246] As seen in 2011, such a reserve margin is likely to result in severe electricity curtailments.[247]

Since the energy-only market payments are insufficient to incentivize enough generation to be built to avoid curtailments, ERCOT has to step in with emergency backstop measures when demand spikes. This suppresses scarcity prices, incentivizing even less capacity to be built and further exacerbating the resource adequacy problem (often referred to as the "missing money" problem).[248] One market mechanism that could respond to demand spikes without the need for emergency administrative measures would be to have enough demand that could respond on its own to high prices. This situation does not exist in ERCOT or any other current electricity market:

> Electricity wholesale markets are more volatile than most commodity markets because they have neither storage capability nor sufficient short-term demand elasticity to moderate consumption during shortages. Most customers are on fixed rates and have no incentive to use less when spot prices are high, even on the hottest day of the year. When demand exceeds available supply, real-time prices rise to the offer cap, and system operators initiate involuntary load shedding. Therefore, load's traditional inelasticity creates reliability challenges without a large generation reserve margin.[249]

ERCOT has not yet reached the level of demand response development necessary to act as a substitute for administrative measures to avoid curtailments.[250] Achieving that level of demand response will be difficult.[251] Bridging the demand response gap "is more challenging than it sounds because ERCOT demand response penetration is currently low and increasing [demand response] penetration is likely to proceed slowly. Moreover, most load is not ideally suited to set prices . . . ."[252] In addition, severe technical challenges persist: "[p]rice-sensitive demand bids are not yet accommodated in any RTO real-time energy market due to technical and communication infrastructure challenges."[253] Finally, while a few demand response programs exist in ERCOT's jurisdiction,[254] the market design will have to be significantly modified to

237. Electric Reliability Council of Texas Power Region, 2012 WL 5462947 (Tex. P.U.C. Oct. 26, 2012).
238. *Id.* at *2.
239. Memorandum from Commissioner Nelson at 4–5, *PUCT Proceeding to Ensure Resource Adequacy in Texas* (Tex. P.U.C. Aug. 9, 2013) (PUCT Project No. 40000), *available at* http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40000_447_763509.PDF.
240. ERCOT, Report on the Capacity, Demand, and Reserves in the ERCOT Region, *supra* note 1, at 8.
241. Newell et al., *supra* note 222, at 9.
242. *Id.*
243. *Id.* at 9–10.
244. *Id.* at 1.
245. Electric Reliability Council of Texas Power Region, 2012 WL 5462947 at *20.
246. *Id.* at *4.
247. Newell et al., *supra* note 222, at 65-67.
248. *See* Joskow, *supra* note 3, at 160, 164.
249. Newell et al., *supra* note 222, at 88. In addition to real time meters, an additional option is "priority rationing contracts" between load serving entities and retail customers who would specify in advance the level of wholesale market prices at which they would allow the system operator to implement demand curtailments. Joskow, *supra* note 3, at 164–65. "However, priority rationing contracts require that the system operator control the flows of power that go to individual customers and to have the capability to curtail individual customer demand on short notice. Except for the very largest customers, control over power flows does not go this far down into the distribution system and system operators can only curtail demand in relatively large 'zones' composed of many customers." *id.*
250. Newell et al., *supra* note 222, at 103.
251. *Id.* at 70–71, 90.
252. *Id.* at 105.
253. *Id.* at 96 n.199.
254. *Id.* at 89.

enable large amounts of demand response to contribute to efficient price formation in real-time.[255]

Since the energy-only market does not incentivize enough generation to be built to maintain resource adequacy and demand response is several years away from preventing major electricity curtailments on its own, the Public Utility Commission of Texas is considering alternatives to ensure resource adequacy. The main option under consideration is one proposed by a generation provider, which would add a market-based structure to the provision of ancillary services and operating reserves through an administratively-set demand curve that allows the prices in those short-run markets to reach an estimated VOLL.[256] High price caps for operating reserves, even reaching an estimated VOLL, will not provide enough generation to avoid significant reliability events for same the reasons discussed above, unless there is compensation to provide a particular amount of operating reserves. This would not be much different from other administratively-set demand curves in capacity markets, except without the capacity market structure. The myriad mechanisms and rules designed to simulate a competitive market while also providing resource adequacy that exist in a capacity market will be missing. Therefore, the Public Utility Commission of Texas is also considering a capacity market mechanism.[257]

At the current time, an energy-only market does not incentivize enough generation to be built to avoid severe reliability events. Therefore, the ideal of allowing a fully deregulated market and a truly competitive market is not currently attainable if resource adequacy is also required. When shortage events arise, ERCOT will be forced to implement non-market backstop mechanisms to avoid electricity service curtailment. This will lower scarcity prices, further reducing the incentive to build capacity. In addition, there will not be enough demand responsive to high prices to avoid administrative backstop mechanisms for years to come. Resource adequacy requirements should be implemented or consumers will face high periodic price spikes and increasing reliability problems. Reasserting jurisdiction over generation to ensure resource adequacy through mandated reserve margins with penalties for failure to comply and guaranteed cost-of-service rates, however, would be contrary to Texas' market-based approach. On the other hand, allowing high price caps in the energy and operating reserve markets alone is unlikely to achieve reserve margins greater than 10%, which will result in the possibility of severe reliability events. As we have seen, the right balance between competition in generation and resource adequacy has been achieved in jurisdictions with robust capacity market mechanisms. Such a market structure will likely be necessary to ensure that a reliable reserve margin is established in Texas.[258]

III. Conclusion

One of the main factors that governs the level of resource adequacy requirements needed for a particular RTO or ISO is the level of deregulation of generation in the states within that region. This factor counsels against implementing more robust backstop resource adequacy requirements by CAISO, in light of the California Public Utility Commission's continued jurisdiction over resource adequacy within California and its robust long-term planning procurement mandates. In these jurisdictions, policy makers have given paramount consideration to reliability. Competition in generation is not the goal. While this more simply assures resource adequacy, it may also incentivize the overbuilding of capacity, increasing the costs of reliability for consumers.

For areas with states that have deregulated generation, however, maintaining appropriate resource adequacy requirements has proved a difficult balancing act. The criticism that PJM has failed to provide the right incentives and mandates to ensure resource adequacy in transmission constrained areas, however, rings hollow. PJM has been able to achieve its desired level of resource adequacy through its robust mandatory capacity auction and penalty structure, while also providing for competition in capacity resources.

Other regions, however, are not as fortunate. While the resource adequacy problem in ISO-NE is real, the adoption of a more robust year-round system to monitor, penalize, and incentivize generators, similar to the one that is already implemented by PJM, will most likely solve its current resource adequacy problem. In ERCOT, the current energy-only market will have to be reformed to achieve adequate reliability for the foreseeable future. ERCOT consumers are likely to face high price spikes accompanied by reliability events, including brownouts and blackouts, until mandatory resource adequacy requirements are implemented. The current proposal to allow high price caps in the operating reserve market is unlikely to provide reserve margins adequate to ensure reliability. Robust capacity markets with significant penalty structures, however, have proven effective at balancing both competition in generation and the need for resource adequacy. Until truly competitive markets are able to ensure resource adequacy, those mechanisms will be needed to balance competition and reliability.

255. *Id.* at 96.

256. Supplemental Comments of IPR-GDF SUEZ Energy North America at 3, 8, *PUCT Proceeding to Ensure Resource Adequacy in Texas* (Tex. P.U.C. Nov. 14, 2012) (PUCT Project No. 40000), *available at* http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40000_355_741583.PDF.

257. *See* Memorandum from Commissioner Nelson, *supra* note 239.

258. *See*, Joskow, *supra* note 3, at 168–70.