

Getting to Utility 2.0: Rebooting the Retail Electric Utility in the U.S.

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I. INTRODUCTION

Fundamental changes are underway in the electric utility industry in the United States. The industry is moving away from the traditional model featuring large, centralized generating stations to an innovative approach involving increased integration of distributed generation (DG) resources and greater reliance on customer-driven energy choices such as energy efficiency and demand response (DR) programs.¹ These changes are largely driven by economics and advancing technology: the costs of DG resources, particularly solar photovoltaic (PV) panels, have declined considerably in recent years, resulting in increased penetration of DG resources and corresponding reductions in electricity demand being placed on the local utility, as customers “self-generate” their own power.² Improved and lower cost technology has also given utility customers an increased ability to exercise control of their energy usage, through demand-side management (DSM) programs. These measures have the effect of reducing the level of electricity sales from the local utility.

Given these trends away from exclusive reliance on the local electric utility, considerable attention has recently been focused on the incompatibility of the utility business model with the widespread deployment of DG resources and this customer-centric business model. In January 2013, the Edison Electric Institute, the association representing all U.S. investor-

1. U.S. DEPARTMENT OF ENERGY (DOE), *Distributed Energy*, available at <http://energy.gov/oe/technology-development/smart-grid/distributed-energy> (DG resources are small-scale electric generating units that are located close to customer loads. Energy efficiency programs encourage utility customers to use less energy while performing the same functions, such as replacing an incandescent lightbulb with a compact fluorescent one or replacing an appliance with a model that uses energy more efficiently). LAWRENCE BERKELEY NATIONAL LABORATORY, *What’s Energy Efficiency*, <http://eetd.lbl.gov/ee/ee-1.html> (DR programs encourage electric customers to reduce or shift their energy usage during peak periods, in response to financial incentives). DOE, *Demand Response*, <http://energy.gov/oe/technology-development/smart-grid/demand-response>.

2. *See infra* Section II.A.

owned electric companies,³ published a report, *Disruptive Challenges*, which highlighted the challenges to the electric utility industry posed by widespread deployment of DG resources.⁴ The report identified a convergence of factors—including the declining costs of DG resources—that potentially could “challenge and transform” the electric utility industry.⁵ According to the report, the traditional utility model of centralized generation could be threatened as these DG technologies become more cost-competitive.⁶ The report concluded that as DG resources achieve increased penetration in the future, the industry and its stakeholders will need to take action to respond to these challenges to minimize the impact of the “disruptive forces.”⁷

Another driver of these fundamental changes occurring in the electric utility industry is the benefit that DG resources provide in improving system resilience in the face of climate change and the increasing frequency of extreme weather events.⁸ In this regard, Hurricane Sandy (ultimately downgraded to “Superstorm” Sandy by the time it hit the coasts of New York and New Jersey in late October 2012) provided a “wake up call” to the industry regarding the vulnerability of the existing utility grid, the resilience benefits of DG resources, and the urgent need

3. EDISON ELECTRIC INSTITUTE, *Mission & Vision*, <http://www.eei.org/about/mission/Pages/default.aspx>.

4. Peter Kind, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*, EDISON ELECTRIC INSTITUTE, 1 (Jan. 2013), <http://www.eei.org/ourissues/finance/Documents/disruptivechallenges.pdf> [hereinafter *Disruptive Challenges*].

5. *Id.* (*Disruptive Challenges* report identified a number of emerging DG technologies that could provide competition for utility-provided services, including solar PV, battery storage, fuel cells, geothermal systems, wind micro turbines, and enhanced storage from electric vehicles). *Id.* at 4.

6. *Id.* at 3.

7. *Id.* at 17.

8. New York Pub. Serv. Comm’n, Case 13-E-0030, *Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal*, 63, n.47 (Feb. 21, 2014), available at <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-E-0030> (The decision of the New York PSC in a recent Con Edison case defined resilience as going beyond the “hardening” of existing utility infrastructure to reduce the impact of severe storms. Adopting the definition from the NYS 2100 Report, the CON EDISON ORDER defined resilience as “the ability of a system to withstand shocks while still maintaining its essential functions.”) [hereinafter CON EDISON ORDER]; *Id.* (citing NYS 2100 COMMISSION, *Recommendations to Improve the Strength and Resilience of the Empire State’s Infrastructure*, 24, <http://www.governor.ny.gov/assets/documents/NYS2100.pdf>) [hereinafter NYS 2100 COMMISSION REPORT].

to engage in long-term planning that focus on strategies to improve the ability of the electric system to cope with the anticipated extreme weather events of the future. About 8.5 million utility customers in the eastern U.S. lost power during Sandy, and more than 650,000 homes were damaged or destroyed.⁹ The experience of Superstorm Sandy provides a case study of the system resilience benefits of DG resources, and the lessons that can be learned as utilities plan for increasingly frequent extreme weather events.

Apart from the impact of Superstorm Sandy on the electric utilities operating in the region, the event provided an opportunity for a fundamental re-examination of the electric utility business model and the associated regulatory framework. Within months of Superstorm Sandy, Consolidated Edison Company of New York (Con Edison), the utility serving New York City, proposed substantial rate increases to cover the expenditures to “harden” the utility system and reinforce the traditional central generation model (and associated transmission and distribution (T&D) systems).¹⁰ Con Edison’s January 2013 rate request in New York included a commitment to spend \$1 billion in “storm hardening structural improvements” over the subsequent four year period.¹¹ The Con Edison rate proceeding before the New York Public Service Commission evolved into an extended proceeding examining the lessons learned from Superstorm Sandy, the need for changes to utility long-term system planning to address climate change, and the possible role of DG resources in improving the resilience of the electric grid.

Shortly after concluding the Con Edison rate proceeding in February 2014, the New York PSC issued a significant order commencing a broader proceeding, Reforming the Energy Vision, or REV, to examine the utility business model and possible changes to the framework for regulating electric utilities.¹² The REV proceeding has attracted substantial national attention, given the comprehensive investigation being undertaken by the New York PSC and the participation of a broad group of stakeholders in the

9. *Id.* at 15; Doyle Rice & Alia Dastagir, *One Year After Sandy, 9 Devastating Facts*, USA TODAY, Oct. 29, 2013, <http://www.usatoday.com/story/news/nation/2013/10/29/sandy-anniversary-facts-devastation/3305985/>.

10. Letter from Craig S. Ivey, President, Con Edison to Jeffrey C. Cohen, Acting Secretary, New York PSC at 1, New York Pub. Serv. Comm’n, Case 13-E-0030, Consolidated Edison Company of New York, Inc., (Jan. 25, 2013) (No. 985), <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={B81F8F41-1051-4A89-877C-81C0DB7FB629}>.

11. *Id.*

12. See New York Pub. Serv. Comm’n, Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Instituting Proceeding* (Apr. 25, 2014), available at <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101&submit=Search+by+Case+Number> [hereinafter REV ORDER].

proceeding.¹³ In addition to the New York proceeding, this examination of a possible new utility business model, commonly referred to as “Utility 2.0,” is being undertaken in several other jurisdictions throughout the country.¹⁴

This Article examines the drivers for this perceived need to revisit the utility business model, focusing primarily on the declining cost of DG resources and the resilience benefits of DG resources in addressing the impact of future extreme weather events. Second, this article reviews the various “Utility 2.0” proceedings underway across the United States, and the common themes emerging from those proceedings. The third section of the Article discusses the possible approaches to a utility business model, based on experience in wholesale and retail electricity markets in the United States and Europe. Fourth, this Article will examine lessons learned regarding the success of business structures in achieving the objective of ensuring nondiscriminatory access to electric network, based on previous industry restructurings, including the actions of the Federal Energy Regulatory Commission (FERC) to restructure the electric industry during the 1990s, as well as the experience in Europe with the various utility business models. Finally, the Article concludes with recommendations and a discussion of the challenges facing regulators as they assume the task of defining the Utility 2.0 business model.

II. DRIVERS OF THE CHANGING UTILITY BUSINESS MODEL

A. Improving Economics of DG Resources

The *Disruptive Challenges* report from the Edison Electric Institute identifies the threat to the traditional utility business model posed by continuing declines in the cost of DG resources, particularly solar PV panels.¹⁵ That document cites a decline in the price of solar PV panels

13. New York Pub. Serv. Comm’n, Case 14-M0101, *DPS Straw Proposal on Track One Issues*, at 2 (Aug. 22, 2014), available at <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={CA26764A-09C8-46BF-9CF6-F5215F63EF62}> [hereinafter TRACK ONE PROPOSAL].

14. See *infra* Section III.

15. *Disruptive Challenges*, *supra* note 4, at 4 (Other forms of DG resources include combined heat and power (CHP, or cogeneration), small wind turbines, fuel cells, and microturbines); *Creating a 21st Century Electricity System for New York State, An Energy Industry Working Group Position Paper*, ADVANCED ENERGY ECONOMY 5 (Feb. 26, 2014), available at <https://www.aee.net/initiatives/21st-century-electricity-system.html#ny-state-energy-industry-working-group> (In addition, to the extent these DG resources are

from \$3.80 per watt in 2008 to \$0.86 per watt in 2012, with anticipated further price decreases as the solar industry continues to scale up.¹⁶ When accompanied by continued increases in the price of electricity sold by utilities, the *Disruptive Challenges* report concludes that energy from solar PV is currently cost-competitive in about 16 percent of the U.S. retail electricity market.¹⁷ By 2017, about one-third of annual electric utility revenue, or \$170 billion, is projected by the solar PV industry to be “in play,” or cost-competitive with grid-supplied electricity.¹⁸ The *Disruptive Challenges* report cites a projected 22 percent compound annual growth rate in installation of solar PV panels through 2020, which would give DG resources about 10 percent of the capacity in certain markets.¹⁹

A more recent analysis by the Department of Energy described cost reductions of 6-7% per year from 1998-2013 for residential and commercial PV systems, and 12-15% from 2012 to 2013.²⁰ Based on current pricing trends, the “all-in” costs of distributed solar PV systems are expected to range between \$1.50 per watt and \$3.00 per watt by 2016.²¹ One consulting firm estimated that continued growth in DG resources and investments in energy efficiency could result in up \$48 billion in reduced revenue for utilities in the U.S. by 2025.²² The percentage of utility executives concerned about the impacts of DG resources causing significant or moderate reductions in future utility revenue streams increased from

fueled by natural gas—as is the case for CHP and microturbines—the cost-competitiveness is enhanced by the currently prevailing low prices for natural gas, which as of December 2014 are below \$4 per MMBtu). *Id.* at 5–6. ENERGY INFORMATION ADMINISTRATION, *Natural Gas Weekly Update* (Dec. 17, 2014), http://www.eia.gov/naturalgas/weekly/archive/2014/12_18/index.cfm.

16. *Id.* (citing BLOOMBERG NEW ENERGY FINANCE, *Solar Module Price Index*); *Id.* (Apart from the cost of the solar PV panel itself, there is the cost of installation. *Disruptive Challenges* cites an “all-in” cost of a solar PV installation as approximately \$5 per watt in 2012).

17. *Id.* (citing ENERGY INFORMATION AGENCY, *Electricity Data Overview*).

18. *Id.*

19. *Id.* at 5.

20. FELDMAN ET AL., U.S. Doe, *SunShot, Photovoltaic System Pricing Trends*, 4 (2014 ed. 2014), <http://www.nrel.gov/docs/fy14osti/62558.pdf> (This represents the fourth year of “sharp declines” in the cost of installed solar PV in the U.S.); Christian Roselund, *U.S. Installed Solar PV Costs Continue to Fall*, PV MAG. (Sep. 18, 2014), http://www.pv-magazine.com/news/details/beitrag/us-installed-solar-pv-costs-continue-to-fall_100016490/#ixzz3Ni5sJCuH.

21. *Id.* This “all-in” cost compares to the \$5 per watt figure cited in *Disruptive Challenges* for 2012.

22. *Utilities Face Significant Revenue Losses from Growth of Solar, Storage and Energy Efficiency*, ACCENTURE (Dec. 8, 2014), <http://newsroom.accenture.com/news/utilities-face-significant-revenue-losses-from-growth-of-solar-storage-and-energy-efficiency-accenture-research-shows.htm>.

43 percent in 2013 to 61 percent in 2014.²³ According to this report, solar PV is already at “grid parity,” or competitive with the cost of grid-produced power, in many states in the U.S., and can be expected to reach parity in most of the remaining states within the next few years.²⁴

In addition to the declining cost of solar PV installations, the threat is exacerbated by public policies favoring renewable resource development. These include net metering provisions in effect in 43 states, which require utilities to purchase the output from solar PVs at the utility’s retail rate,²⁵ tax incentives that provide a 30% investment tax credit for various renewable resources,²⁶ and time-of-use pricing by utilities, which improve the economics of solar PV installation by paying higher prices during daylight hours when the panels produce the most electrical output.²⁷

B. Climate Change, Utility System Resilience and Lessons Learned from Superstorm Sandy

Superstorm Sandy represented the worst natural disaster in Con Edison’s history,²⁸ resulting in about one-third of Con Edison’s customers—1,115,000 out of 3.3 million—losing power.²⁹ However, many commercial and industrial facilities and educational institutions in the area (including Princeton University’s campus in New Jersey and New York University’s campus in lower Manhattan) were largely able to maintain operations, due to on-site DG facilities, primarily cogeneration or combined heat and power (CHP) facilities.³⁰ The experience from Superstorm Sandy

23. *Id.*

24. *Id.*

25. *Net Metering*, DSIRE (Jan. 2015), <http://www.dsireusa.org/resources/detailed-summary-maps/>.

26. *Federal Incentives/Policies for Renewables & Efficiency, Residential Renewable Energy Tax Credit*, DSIRE (Oct. 2014), available at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US37F&re=1&ee=1.

27. *Disruptive Challenges*, *supra* note 4, at 4.

28. Con Edison, *Superstorm Sandy, 2013 State of the Company*, <http://www.conedison.com/ehs/2012-sustainability-report/engaging-stakeholders/reliability/superstorm-sandy/index.html#gsc.tab=0>.

29. New York Pub. Serv. Comm’n, Case 13-E-0030, Testimony of Electric Infrastructure and Operations Panel, at 15, available at <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A3EFED44-5E61-42B6-9348-7AB59BAA8CB5}>.

30. As noted in the NYS 2100 COMMISSION REPORT, CHP or cogeneration facilities were “able to keep the lights on during the hurricane using microgrids.” NYS 2100 COMMISSION REPORT, *supra* note 8, at 101. A combined heat and power (CHP) system

demonstrates how DG resources can improve the resilience of the electrical grid and mitigate the impacts of an outage by enabling critical facilities to maintain essential operations.³¹ If the electrical grid is experiencing an outage, DG systems can be configured to “island” from the grid, thereby maintaining uninterrupted power supplies to utility customers within a “microgrid.”³² That was the experience from Superstorm Sandy, where the use of microgrids and DG resources enabled power to be provided to pockets of utility customers in the face of widespread outages of central power plants and the associated T&D systems.³³

As described above, Con Edison’s January 2013 rate filing included a commitment to spend \$1 billion over four years to “harden” its system in response to the widespread outages experienced during Superstorm Sandy.³⁴ In contrast to this “business as usual” approach proposed by Con

is a DG resource that uses an on-site electrical generator, typically fueled by natural gas, to provide electricity and thermal energy (usually in the form of steam or water) to a single large building or, in the case of a microgrid or district energy system, to a campus or group of facilities. After capturing heat that would otherwise be wasted as a byproduct of electricity generation, a CHP system converts that heat into useful thermal energy for space heating, cooling or other processes. EPA, *Combined Heat and Power Partnership, Basic Information*, <http://www.epa.gov/chp/basic/index.html>.

31. Joel E. Eisen, *Distributed Energy Resources, “Virtual Power Plants,” and the Smart Grid*, 7 ENV’T L & ENERGY L. & POL’Y J. 191, 193 (2012) (Distributed energy resources “help the electric grid by increasing grid reliability and resilience, making the grid less vulnerable to prolonged power failures.”).

32. Microgrids are small distribution systems that can interconnect and coordinate a number of DG resources into a network capable of serving all or a portion of the energy needs of a cluster of users. NEW YORK STATE ENERGY AND RESEARCH DEVELOPMENT AUTHORITY, *Microgrids: An Assessment of the Value, Opportunities and Barriers to Deployment in New York State* (2010), available at www.nyserda.ny.gov, at S-1. Depending upon their configuration, microgrids can be “islanded” to operate independently from the utility grid. NYS 2100 COMMISSION REPORT, *supra* note 8, at 95. (“Microgrids’ refers to clusters of homes and buildings that share a local electric power generation and/or energy storage device while disconnected from the utility grid.”)

33. NYS 2100 COMMISSION REPORT, *supra* note 8, at 101. Following Superstorm Sandy, the consulting firm ICF International prepared a report highlighting the role of DG resources, and CHP facilities in particular, in enhancing the resilience of critical infrastructure facilities during the extended power outages caused by Superstorm Sandy. ICF INTERNATIONAL, *Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities*, Mar. 2013, available at <http://www.harc.edu/sites/default/files/documents/projects/CHP%20Critical%20Facilities.pdf>, at 4 [hereinafter ICF REPORT]. The ICF Report includes fourteen “case studies” where CHP facilities improved system resiliency through “mitigating the impacts of an emergency by keeping critical facilities running without any interruption in electric or thermal service.” *Id.* at 4–30.

34. Letter from Craig S. Ivey, President, Con Edison to Jeffrey C. Cohen, Acting Secretary, New York PSC, New York Pub. Serv. Comm’n (Jan. 25, 2013), available at <http://www.coned.com/documents/2013-rate-filings/filing-letter-and-attachments.pdf>. The measures for storm hardening of critical infrastructure incorporated undergrounding

Edison, however, a consortium of environmental groups (NGO Parties) proposed a fundamental re-examination of the manner in which electric utility service is delivered, with a focus on measures that improve the resilience of the grid.³⁵ Rather than relying on traditional methods to prepare for the next major storm based on the weaknesses exposed by the last one, the NGO Parties urged that the priorities of a utility's major capital expenditures be aligned toward investing in the "utility of the future"—a utility designed to withstand the extreme weather events that are likely to occur decades into the future.³⁶

On December 31, 2013, a settlement agreement among most of the parties, including the NGO Parties, was submitted to the PSC.³⁷ On particular note, the *Joint Proposal* contains agreements with respect to DG issues and the deployment of microgrids within Con Edison's service territory.³⁸ In its February 2014 order adopting the *Joint Proposal*, the PSC directed a fundamental change in the manner in which Con Edison plans for future capital investments, and required analysis of alternative resilience strategies, including microgrids.³⁹ The *Con Edison Order* was noteworthy in several respects. First, the PSC largely rejected the "business as usual" approach offered by Con Edison, which responded to

of some facilities as well as flood protection projects, such as installation of flood walls, raising the elevation of critical equipment, and use of submersible equipment, *id.*

35. The "NGO Parties" comprised the Pace Energy and Climate Center (Pace), Natural Resources Defense Council (NRDC), Environmental Defense Fund (EDF), and the Columbia Law School Center for Climate Change Law (Columbia). New York Pub. Serv. Comm'n, Case 13-E-0030, Testimony of Jackson Morris, Pace Energy & Climate Center, *available at* <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={81F2C4EB-EE3C-4921-B0F5-C5F4C6E24EF3}>, at 5.

36. *Id.* The National Climate Assessment notes that "U.S. energy facilities and systems, especially those located in coastal areas, are vulnerable to extreme weather events." U.S. GLOBAL RESEARCH PROGRAM, *Climate Change Impacts in the United States, Chapter 4, Energy Supply and Use, available at* <http://nca2014.globalchange.gov/report/sectors/energy>, at 115. The impacts of extreme weather events "are expected to increase in the future." *Id.* at 114.

37. *See* New York Pub. Serv. Comm'n, Case 13-E-0030, *Joint Proposal*, Dec. 31, 2013, *available at* <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-E-0030> [hereinafter *Joint Proposal*].

38. *Id.* at 96–97.

39. *Id.* at 67–68. The CON EDISON ORDER directed Con Edison to "develop and apply a cost/benefit analysis approach for future capital investment that differs from a typical utility capital expenditures analysis and assesses the relative benefits of existing utility infrastructure and alternative resilience approaches such as microgrids."

Superstorm Sandy by proposing massive, traditional investments in T&D infrastructure to “harden” the system against future storms.⁴⁰ In its place, the PSC enunciated a strategy much more focused on improving the resilience of the utility grid, which may depart from T&D infrastructure investments depending upon the outcome of an innovative cost-benefit analysis that Con Edison must apply to its future capital investments.⁴¹ Second, the *Con Edison Order*, by adopting the *Joint Proposal* and the specific commitments therein, recognized the valuable role that DG resources and microgrids can play in improving the resilience of a utility system in the face of future extreme weather events.⁴² The *Con Edison Order* requires Con Edison to take specific steps to pursue integration of DG resources in its service territory and to investigate the feasibility of microgrid installations.⁴³

The *Con Edison Order* was also noteworthy because the “lessons learned” from Superstorm Sandy triggered a more fundamental evaluation of the utility business model. Within two months of issuing its order in the Con Edison rate proceeding, the New York PSC commenced the REV proceeding, which was geared toward examining electric utility practices in light of the trends in the generation and distribution of electricity and technological advances in managing information.⁴⁴ Given these changes, the PSC perceived a need to align its regulatory paradigm with the new dynamics in the electric utility industry.⁴⁵ Section III.A. below describes the REV proceeding.

C. Other Drivers

In addition to declining costs of DG resources and climate change/system resilience objectives, a number of other drivers contribute to the perceived need to re-examine the utility business model. These include declining electricity sales due to increased investment in energy efficiency measures and participation in demand response (DR) programs by retail customers;⁴⁶ the cost pressures faced by electric utilities given their need

40. CON EDISON ORDER, *supra* note 8, at 24.

41. *Id.* at 67–68.

42. *Id.* at 70.

43. *Id.*

44. REV ORDER, *supra* note 12.

45. *Id.*

46. *Disruptive Challenges*, or example, notes that energy efficiency and DSM programs not only result in reduced utility revenues, but also burden the utility with implementation costs of energy efficiency and DSM programs. *See Disruptive Challenges*, *supra* note 4, at 3. Demand response programs reward customers for being able to reduce their electricity use when requested by the utility, usually during periods of high power prices or when the reliability of the grid is threatened.

to replace aging generation and delivery infrastructure;⁴⁷ technological developments in information systems, which enhances the capability of retail electric customers to manage their energy usage;⁴⁸ heightened demands by customers for a high quality (i.e., uninterrupted) electricity supply;⁴⁹ the tools given to both utilities and retail customers to respond to increased volatility in electricity prices;⁵⁰ and the pursuit of public policy objectives geared toward reducing greenhouse gas (GHG) emissions to mitigate the impact of climate change.⁵¹

III. CURRENT PROCEEDINGS EXAMINING THE UTILITY 2.0 BUSINESS MODEL

A. New York's REV Proceeding

In its April 2014 order instituting the REV proceeding, the New York PSC indicated its intention to consider “fundamental changes in the manner in which utilities provide service” and the possibility of a “substantial transformation” of the utility business model.⁵² A key question to be addressed would focus on the role of the incumbent retail electric utility in a system geared toward integration of DG resources and customer-centered load management practices, with the goal of achieving

47. REV ORDER, *supra* note 12, Att. 1 at 2. In the REV proceeding, DPS Staff estimated that \$30 billion would be spent on utility delivery and central generation infrastructure over the next ten years. See REV Collaborative Meeting Presentation, *Reforming the Energy Vision (REV)*, (May 12, 2014), available at [http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/\\$FILE/REV%205.12.14%20Collaborative%20Meeting.pdf](http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/REV%205.12.14%20Collaborative%20Meeting.pdf), at 3.

48. The PSC noted the technological developments that have made it more feasible to deploy alternative methods to manage and satisfy retail customer loads. These developments include advances in telecommunications, controls for industrial systems, and DG resources, *id.* at 3–4. Investments in smart grid technology create new opportunities for customers to manage their energy use and actively participate in grid operations, such as through DR programs. See ADVANCED ENERGY ECONOMY, *Creating a 21st Century Electricity System for New York State, An Energy Industry Working Group Position Paper*, available at <https://www.aee.net/initiatives/21st-century-electricity-system.html#ny-state-energy-industry-working-group>, at 6.

49. REV ORDER, *supra* note 12, at 2. The PSC referred to the “demands of the digital economy,” which have resulted in greater economic costs associated with outages and forced customers to consider self-generation as a supplement to grid-supplied power, *id.* at 2–3.

50. *Id.*

51. *Id.*

52. *Id.* at 4–5.

greater efficiencies in the system.⁵³ The PSC identified six policy objectives to guide the proceeding: providing better information and more tools to customers to manage their energy bills; stimulating the market and “leveraging” the contributions from utility ratepayers; improving the efficiency of the utility system; achieving greater diversity in energy resources; improving the reliability and resilience of the utility grid; and reducing GHG emissions.⁵⁴ Given the “foundational steps” that New York has previously taken to encourage the integration of DG resources into the utility grid and the presence of a single-state wholesale market (administered by the New York ISO), the PSC concluded that New York was “particularly well-suited” to take the lead in the examination of possible new utility business models.⁵⁵ The *REV Order* also recognized the changes in ratemaking practices that must accompany any transformation of the utility business model.⁵⁶

In a Report and Proposal that accompanied the *REV Order*, the PSC Staff articulated a new business model for the electric distribution system that identified the foundational utility service as a “distribution system platform provider,” or DSP.⁵⁷ As described in the Report and Proposal, this entity would be charged, among other things, with planning and designing its distribution system to facilitate a prominent role for DG resources in meeting system needs;⁵⁸ creating markets, tariffs and operations systems to facilitate integration of “behind-the-meter” resource providers, such as energy efficiency and DR programs, building management systems, and microgrids;⁵⁹ providing information technology and real-time pricing information among market participants, including pricing structures for DG products and services;⁶⁰ serving as the primary interface among retail customers in distribution markets and between retail customers and the wholesale markets (i.e., aggregating products for purpose of offering them to the New York ISO);⁶¹ serving as the local balancing authority (i.e., balancing loads and resources to meet customer needs and maintain reliability);⁶² and developing communications networks capable of supporting a smart grid.⁶³

53. *Id.* at 2.

54. *Id.*

55. *Id.* at 4.

56. *Id.* at 4–5.

57. *Id.* at 6.

58. *Id.* at Att. 1, at 12.

59. *Id.*

60. *Id.* at 12, 20.

61. *REV ORDER*, *supra* note 12, Att. 1, at 12.

62. *Id.* at 22.

63. *Id.* at 23.

The *REV Order* established two parallel tracks for the proceeding—one to examine the utility business model, and the second to examine the regulatory framework and ratemaking issues.⁶⁴ The proceeding attracted an unprecedented number of parties—259 stakeholders have intervened in the case⁶⁵—as well as considerable national attention.⁶⁶ One commenter referred to REV as a “landmark regulatory proceeding” the outcome of which “will reverberate across the country” as other states wrestle with the same underlying drivers.⁶⁷ In addition to the Staff Report and Proposal issued with the *REV Order*, Staff issued its proposal with respect to Track One issues on August 22, 2014.⁶⁸ Staff’s recommendations in the *Track One Proposal* are discussed further in Section IV.B below. The PSC issued its order on Track One issues in late February 2015, also discussed further below.⁶⁹ Staff will present its proposal on Track Two issues on June 1, 2015.⁷⁰

B. Hawaii PUC’s “Inclinations on the Future of Hawaii’s Electric Utilities”

Hawaii, with its heavy reliance on oil-fired electric generation, has the nation’s highest electricity rates.⁷¹ As a result, the threat to the utility

64. *Id.* at 6.

65. TRACK ONE PROPOSAL, *supra* note 13, at 2.

66. See Matthew Wald, *State Energy Plan Would Alter New York Utilities*, N.Y. TIMES, May 4, 2014, available at http://www.nytimes.com/2014/05/05/nyregion/state-energy-plan-would-alter-new-york-utilities.html?_r=0; Gargi Chakrebarty, *REV It Up in New York*, ENERGYBIZ, Sept./Oct. 2014, available at <http://www.energybiz.com/magazine/article/368385/rev-it-new-york>; Stephen Lacy, *New York’s Energy Czar: We Need Clean Energy Markets, Not Programs or Mandates*, GREENTECH GRID, Nov. 24, 2014, available at <http://www.greentechmedia.com/articles/read/new-york-energy-czar-we-need-clean-energy-markets-not-programs>.

67. Ryan Katofsky and Lisa Frantzis, *Devil is in the Details on NY’s Reforming the Energy Vision*, ADVANCED ENERGY ECONOMY, Sept. 11, 2014, available at <http://blog.aee.net/devil-is-in-the-details-on-nys-reforming-the-energy-vision>.

68. TRACK ONE PROPOSAL, *supra* note 13.

69. New York Pub Serv Comm’n, Case 14-M-0101, *Order Adopting Regulatory Policy Framework and Implementation Plan*, Feb. 26, 2015, available at <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101&submit=Search+by+Case+Number> [hereinafter TRACK ONE ORDER].

70. *Id.* at 131.

71. Davide Savenije and Claire Cameron, *Hawaii’s Overhaul of the Utility Business Model*, UTILITY DIVE, May 7, 2014, available at <http://www.utilitydive.com/news/hawaii-provides-us-utilities-a-glimpse-of-the-future/272824/>. The HECO Companies comprise Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Ltd.

business model posed by DG resources is more urgent for Hawaii's electric utilities.⁷² A report from the Rocky Mountain Institute concluded that the economics of “grid defection”—the ability to drop off the traditional utility grid using distributed solar generation and storage—are already tilting in favor of electricity customers in Hawaii.⁷³ According to the report, because of the high retail electricity prices in Hawaii, it is already cost-effective for a commercial customer in Honolulu to drop off the grid with a solar-plus-battery installation and a standby diesel generator.⁷⁴ Another driver for renewable energy in Hawaii is its fairly aggressive renewable portfolio standard, with an obligation to achieve 40% renewable energy by 2030.⁷⁵ The state already met its 2015 renewables target of 15%,⁷⁶ and renewables met more than 18% of HECO Companies' customers' energy needs in 2013.⁷⁷ There are 43,000 PV systems in the area served by the HECO Companies, up from 850 PV systems in 2008.⁷⁸

The Hawaii PUC started examining “the utility of the future” in May 2013, with its order in a general rate proceeding involving Maui Electric Company, one of the HECO Companies.⁷⁹ In an exhibit to the rate order, the PUC offered “observations and perspectives” to address “fundamental, emerging issues” facing investor-owned electric utilities in Hawaii.⁸⁰ The PUC observed that the HECO Companies (one of which is Maui Electric) “appear to lack movement to a sustainable business model to address technological advancements and increasing customer expectations.”⁸¹ One year later, the Hawaii PUC rejected the HECO

72. *Id.* (stating that Hawaiian Electric Company, the state's biggest electric utility, has an avoided cost of generation of \$0.22697/kWh, which is almost fifty percent higher than the average leveled price of utility-scale solar (\$0.15576/kWh).

73. ROCKY MOUNTAIN INSTITUTE, HOMER ENERGY AND COHNREZNICK THINK ENERGY, THE ECONOMICS OF GRID DEFECTION, 37 (FEB. 2014), http://www.rmi.org/electricity_grid_defection.

74. *Id.*

75. *Renewable Portfolio Standard*, DSIRE, <http://programs.dsireusa.org/system/program/detail/606> (last visited Mar. 4, 2015).

76. Savenije & Cameron, *supra* note 71.

77. Davide Savenije, *Hawaii Provides U.S. Utilities a Glimpse of the Future*, UTILITY DIVE (June 11, 2014), <http://www.utilitydive.com/news/hawaii-provides-us-utilities-a-glimpse-of-the-future/272824/>.

78. *Id.*

79. Maui Elec. Co., Ltd., Docket No. 2011-0092, Order No. 31288, Haw. Pub. Util. Comm'n (May 31, 2013), http://dms.puc.hawaii.gov/dms/OpenDocServlet?RT=&document_id=91+3+ICM4+LSDB15+PC_DocketReport59+26+A1001001A13F03B43854C1206218+A13F03B43854C120621+14+1960. In its decision, the Hawaii PUC ordered a rate reduction of \$7.7 million (resulting in a refund of over \$8 million) and reduced Maui Electric's return on equity from 10% to 9%, with half of that reduction attributed to inefficiencies found in the utility's operations, *id.* at 107, 140.

80. *Id.* at Ex. C1.

81. *Id.* at 3.

Companies' integrated resource plan, finding an absence of such a correction or any evidence of progress by the utility on "developing and implementing a sustainable business model."⁸² In Exhibit A to the IRP Order, the PUC delivered its *Inclinations on the Future of Hawaii's Electric Utilities*, which essentially outlined its guidance for the HECO Companies in developing that sustainable business model.⁸³

More broadly, however, the *Inclinations* document represents the PUC's response to what it perceives as the rapidly evolving nature of the electric utility business.⁸⁴ The PUC enunciated a goal of developing a "21st Century Generation System" that would more easily integrate clean energy resources to displace current reliance on expensive oil-fired generation.⁸⁵ A second element of the *Inclinations* document addressed the development of a modern electric grid. On this point, the emphasis was placed on the seamless integration of DG resources, and providing customers with the information necessary to make wise energy choices.⁸⁶ With respect to distribution system infrastructure, the PUC noted the recent exponential growth in rooftop solar PV systems, and required the development of a distributed generation interconnection plan that would include, among other things, a discussion of how the utility will manage an integrated portfolio of DG resources to optimize the system and maximize customer benefits.⁸⁷ The final element of the *Inclinations* document addresses the policy and regulatory reforms necessary to facilitate a clean energy future for Hawaii. The PUC observed that the role of the utility is evolving to become more of a "network systems integrator and operator," with consumers taking on the role of "prosumers"—customers who both consume and use utility services and may also provide

82. Maui Elec. Co., Ltd., Docket No. 2012-0036, Order No. 32052, Exhibit A: Commission's *Inclinations on the Future of Hawaii's Electric Utilities 2* (Apr. 28, 2014), available at <http://puc.hawaii.gov/wp-content/uploads/2014/04/Decision-and-Order-No.-32052.pdf> [hereinafter *Inclinations*]. Integrated resource planning is a process whereby utilities examine their resource options, both supply-side and demand-side, over the long term—usually twenty years—and then develop a series of short-term actions to implement the plan. RACHEL WILSON & PAUL PETERSON, SYNAPSE ENERGY ECON., A BRIEF SURVEY OF STATE INTEGRATED RESOURCE PLANNING RULES AND REQUIREMENTS 3, 7, 9 (2011), available at http://www.cleanskies.org/wp-content/uploads/2011/05/ACSF_IRP-Survey_Final_2011-04-28.pdf.

83. *Inclinations*, *supra* note 82, at 1.

84. *Id.*

85. *Id.* at 3.

86. *Id.* at 3, 10.

87. *Id.* at 15.

services to the utility.⁸⁸ Over time, the PUC saw HECO Companies' role as an "independent" power supply integrator and operator of the electric grid in Hawaii, much like the role performed by regional transmission organizations (RTOs) and independent system operators (ISOs) in the wholesale electricity markets.⁸⁹

In an order issued on the same day as the IRP Order, the Hawaii PUC required the HECO Companies to file action plans to address the issues identified in the IRP Order and the *Inclinations* document.⁹⁰ In an unrelated matter, NextEra Energy, based in June Beach, Florida, announced on December 3, 2014 that it was paying \$4.3 billion (and assuming \$1.7 billion in debt) to acquire the HECO Companies.⁹¹ The announcement of the acquisition of the HECO Companies will complicate the PUC's evaluation of HECO Companies' August 2014 filings. As a practical matter, the implementation of the energy future envisioned by the PUC in its *Inclinations* document will likely be explored thoroughly in the merger proceeding. Given the background and experience of NextEra Energy Resources in renewable energy, the merger proceeding can be expected to focus on the pace at which the HECO Companies plan to implement the "sustainable business model," including integrating substantial additional renewable resources.

C. California's Distribution Resource Plans

In 2013, the California legislature passed AB 327, which includes major changes to the state's energy policies.⁹² Among other things,

88. *Id.* at 3, 16.

89. *Id.* at 20.

90. Proceeding to Review Haw. Elec. Co., Inc., & Maui Elec. Co., Ltd.'s Demand-Side Management Reports & Requests for Program Modifications, Haw. Pub. Util. Comm'n, Docket No. 2007-0341, Order No. 32054 (Apr. 28, 2014). On August 26, 2014, the HECO Companies filed a power supply improvement plan, a distribution generation interconnection plan, and an integrated interconnection queue proposal. Press Release, Haw. Pub. Util. Comm'n, PUC Receives the HECO Companies, Action Plans to Achieve State Energy Goals, 1–2 (Aug. 26, 2014) (on file with author). The PUC is in the process of evaluating the filings to determine whether they comply with its April orders and the state's energy goals, *id.* at 2.

91. Press Release, NextEra Energy & Haw. Elec. Indus. to Combine, 4 (Dec. 3, 2014) (on file with authors) (providing the transaction must be approved by the Hawaii PUC and HEI shareholders and is expected to be completed by December 2015).

92. 2013 Cal. Legis. Serv. Assem. B. No. 327, ch. 611 (West).

AB 327 addresses net metering,⁹³ the state’s renewable portfolio standard,⁹⁴ natural gas and electricity rates,⁹⁵ and electricity resources.⁹⁶ Of particular relevance to this article is AB 327’s addition of Section 769 to the public utilities code.⁹⁷ Section 769 relates to electric distribution planning by the state’s investor-owned utilities, and requires each of the utilities to submit distribution resource plans (DRPs) to the California PUC by July 1, 2015.⁹⁸ The statute defines “distributed resources” broadly to include renewable DG resources, as well as energy efficiency, energy storage, electric vehicle, and demand response.⁹⁹ California’s three major utilities—Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric—spend about \$6 billion per year on investments in the distribution grid, but current distribution planning efforts fail to take into account the role that distributed resources could have in reducing costs for utility customers.¹⁰⁰ Maximizing the value of these resource additions to the grid is particularly important given that as much as 15 gigawatts of distributed resources could come on line in California before the end of this decade, including 12 gigawatts of distributed solar, 1 gigawatt of grid-scale energy storage, and 1 gigawatt of demand response.¹⁰¹

93. *Id.* Net Metering allows electricity customers generating their own electricity (e.g., solar panels) to use any excess electricity to offset electricity that the customer would otherwise have to purchase from the utility at the retail rate. *Glossary*, DSIRE, <http://programs.dsireusa.org/system/program/detail/40>.

94. Assemb. B. 327, *supra* note 92 (authorizing CPUC to require utilities procure renewable energy resources in excess of the stated requirements); *Glossary*, *supra* note 93 (“Renewable portfolio standards (RPSs) require utilities to use or procure renewable energy or renewable energy credits (RECs) to account for a certain percentage of their retail electricity sales—or a certain amount of generating capacity—according to a specified schedule.”).

95. Assemb. B. 327, *supra* note 92 (amending the California Alternative Rates for Energy (CARE) program, which provides lower rates to low-income customers); CAL. PUB. UTIL. CODE § 739.1 (2014).

96. Assemb. B. 327, *supra* note 92.

97. CAL. PUB. UTIL. CODE § 769 (2014).

98. *Id.*

99. CAL. PUB. UTIL. CODE § 769(a) (2014).

100. Jeff St. John, *California Takes Its First Step Toward Creating the Distributed, Intelligent Grid of the Future*, GREENTECHMEDIA (Aug. 12, 2014), <http://www.greentechmedia.com/articles/read/california-takes-its-first-step-toward-a-distributed-grid-future>.

101. *Id.*; Craig Lewis, *It’s Time for Grid Planners to Put Distributed Resources on Par with Transmission*, GREENTECHMEDIA, (Nov. 13, 2013), <http://www.greentechmedia.com/articles/read/its-time-for-grid-planners-to-put-distributed-resources-on-par-with-transmission> (providing In addition to maximizing the value of distributed resources for utility customers, taking these resources into account in distribution planning can also avoid potential stranded

The purpose of the DRP process is to require the utilities to identify “optimal locations” to deploy distributed resources,¹⁰² with a goal of achieving full integration of these resources into utilities’ distribution planning operations and investments.¹⁰³ In developing their DRPs, utilities must evaluate the benefits and costs of distributed resources by location and incorporate various factors.¹⁰⁴ These factors include the need for local generation capacity; whether the particular location for the distributed resource will reduce or increase investments in the distribution infrastructure; any safety or reliability benefits; and any other savings that might accrue, either to ratepayers or the electric grid, as a result of deployment of the distributed resource.¹⁰⁵ The utilities must then develop standard tariffs, contracts or other arrangements that promote the deployment of cost-effective distributed resources in a manner consistent with these distribution planning objectives.¹⁰⁶ In their DRPs, the utilities are required to develop a combination of existing programs, incentives and tariff provisions to deploy distributed resources where they have the most value and to minimize the costs of these resources.¹⁰⁷ Finally, Section 769 acknowledges that additional utility spending may be necessary to integrate distributed resources into the distribution planning process, and the DRP must identify such additional costs, consistent with providing net benefits to utility customers.¹⁰⁸

In August 2014, the California PUC initiated a rulemaking for the purposes of establishing policies and procedures to guide the utilities in developing their DRPs.¹⁰⁹ Under the schedule for the proceeding, the PUC expects to issue its ruling with final guidance for development of DRP proposals in late January 2015.¹¹⁰ As noted above, Section 769 requires each utility to file its DRP by July 1, 2015, with PUC approval expected in March 2016.¹¹¹

costs in the future if utilities continue to make traditional investments in central generation and transmission infrastructure, which could become prematurely obsolete as a result of distributed resources).

102. CAL. PUB. UTIL. CODE § 769(b) (2014).

103. Order Instituting Rule Making Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769, Cal. Pub. Util. Comm’n 4, *available at* <http://energystorage.org/system/files/resources/102036703.pdf>.

104. CAL. PUB. UTIL. CODE § 769(b)(1) (2014).

105. *Id.*

106. CAL. PUB. UTIL. CODE § 769(b)(2) (2014).

107. CAL. PUB. UTIL. CODE § 769(b)(3) (2014).

108. CAL. PUB. UTIL. CODE § 769(b)(4) (2014).

109. *See* Order Instituting Rulemaking, *supra* note 103.

110. *Id.* at 10.

111. *Id.* Another relevant development in California is the requirement imposed by the PUC that the state’s three investor-owned utilities procure 1,325 MW of energy

D. Massachusetts's "Grid Modernization" Proceeding

In June 2014, the Massachusetts Department of Public Utilities (DPU) issued two orders that address its vision for a new energy future. The first, involving modernization of the electric grid, outlines four objectives for modernizing the electric grid and promoting new technologies, with a goal toward creating a "modern electric system" that is "cleaner, more efficient and reliable, and will empower customers to manage and reduce their energy costs."¹¹² The objectives are (1) reducing the effects of outages, (2) optimizing demand through reducing peak demand (by enabling customers to respond to price signals) and promoting end-use efficiency, (3) integrating distributed resources (including renewable energy resources, microgrids, electric vehicles, and energy storage), and (4) improving workforce and asset management.¹¹³ The order directs Massachusetts utilities to file 10-year grid modernization plans within nine months.¹¹⁴ These plans must identify how the utilities propose to make measurable progress towards achieving the identified grid modernization objectives.¹¹⁵

The second order, involving time-of-use rates, requires Massachusetts's utilities to switch their default pricing plan from flat rates to time-variable

storage. As a result of these activities, California received the highest score (along with Texas) in the 2014 Grid Modernization Index, as calculated by the GridWise Alliance and the Smart Grid Policy Center. GRIDWISE ALLIANCE/SMART GRID ALLIANCE CENTER, *2014 Grid Modernization Index*, Nov. 17, 2014, <http://www.gridwise.org/>. This index attempts to rank and analyze the states with respect to their progress in moving toward modernized electric "Grid of the Future." *Id.* at V. Part of this analysis involves necessary changes in the "business structure and operating mindset" of electric utilities to become more service-oriented rather than mere commodity suppliers. *Id.*

112. Investigation by the Dep't of Pub. Util. on its own Motion into Modernization of the Electric Grid, Mass. D.P.U. 12-76-B (June 12, 2014).

113. *Id.* at 2.

114. *Id.* at 5.

115. *Id.* at 2. In addition, the utilities are required to submit a five-year short-term investment plan detailing the proposed capital investments, *id.* at 3. Investments identified in this short-term plan are eligible for pre-authorization, which gives the utilities assurances that the decision to proceed with the projects will not subsequently be challenged by the D.P.U.. *Id.* at 3–4. To provide additional incentive for such investments, the order adopts a capital expenditure tracking mechanism for cost recovery of the incremental capital investments identified in the short-term plan. *Id.* at 4. Through use of a tracking mechanism, the utilities achieve quicker rate recovery of the capital costs, which reduces the risks associated with grid modernization investments. *Id.*

and critical peak pricing plans.¹¹⁶ Of more relevance to issues associated with the “utility of the future,” time-varying rates also provide incentives—through stronger price signals—for DG resources such as solar PV, as well as for electricity storage, electric vehicles, energy efficiency and demand response.¹¹⁷ Although one observer described these orders as part of the “pathway to the so-called utility 2.0,” another observer noted that Massachusetts is not seeking to “reinvent” its utilities through these orders, but simply to address the issue of reducing peak demand.¹¹⁸

E. Maryland’s Utility 2.0 Project

In July 2012, then-Governor Martin O’Malley signed an Executive Order commencing a process to explore improving the resiliency and reliability of Maryland’s electric distribution system.¹¹⁹ The Executive Order cited numerous extreme weather events (including hurricanes, blizzards, and derechos) and the likelihood that, due to climate change, the state would continue to suffer “violent weather patterns” in the future.¹²⁰ That process culminated in the Report of the Grid Resiliency Task Force in September 2012 which, among other things, included a recommendation to develop a “Utility 2.0” pilot proposal as a “viable method to explore the contours of the utility of the future.”¹²¹ The Task Force Report observed that the “utility industry was transforming at a pace unseen in its history,” driven by breakthroughs in technology, improved analytics regarding

116. Investigation by the Dep’t of Pub. Util. upon its own Motion into Time Varying Rates, Mass. D.P.U. 14-04-B, at 8 (June 12, 2014). Under the plan, customers would pay three different prices for electricity depending on whether they are using power on-peak, off-peak, or during critical peak demand periods (when wholesale prices are extremely high), *id.* at 8-9. Customers who prefer a flat rate plan will have such option in their basic service, but will still be eligible for peak demand rebates if they reduce their electricity usage during times when wholesale hourly energy prices are the highest. *Id.* at 10. According to the DPU, time-varying rates will allow customers to respond to the actual variances in the price of electricity, which will enable individual customers to save money by altering usage and benefit all customers through reducing peak energy and capacity costs. *Id.* at 1.

117. *Id.* at 1.

118. Claire Cameron, *Inside Massachusetts’ Ambitious Plans to Modernize the Grid*, UTILITY DIVE (Jun. 27, 2014), <http://www.utilitydive.com/news/inside-massachusetts-ambitious-plans-to-modernize-the-grid/279535/>.

119. GEN. ASSEMB. OF MD., DEP’T OF LEGIS. SERV., IMPROVING THE RESILIENCY OF MARYLAND’S ELECTRIC DISTRIBUTION SYSTEM, EXEC. ORDER 01.01.2012.15, at 51 (2012), available at <http://mgaleg.maryland.gov/Pubs/LegisLegal/2012-executive-orders.pdf>.

120. *Id.*

121. OFFICE OF GOVERNOR MARTIN O’MALLEY, WEATHERING THE STORM: REPORT OF THE GRID RESILIENCY TASK FORCE 89 (2012), available at <http://msa.maryland.gov/megafile/msa/speccol/sc5300/sc5339/000113/015000/015223/unrestricted/20121059e.pdf>.

energy usage, and new options for communications with customers.¹²² At the same time, utilities are expected to adapt to various policy objectives, including expansion of renewable energy sources, decreases in energy usage, and reductions in GHG emissions.¹²³ Given this “transformative time in Maryland’s energy future,” the Task Force urged the use of a pilot to explore the transition of the electric utility industry into a “Utility 2.0” model, and further recommended development of a formal proposal for the “utility of the future.”¹²⁴

Pursuant to the recommendation of the Task Force, the Energy Future Coalition in October 2012 assumed the task of creating the “Utility 2.0” model for Maryland.¹²⁵ In March 2013, the Coalition issued the Maryland Utility 2.0 Report. The report was issued, and offered a “pilot project design” with six attributes for the electric utility of the future: (1) align utility incentives with customers’ needs through performance parameters (and adjustments to the utility’s return on equity) based on cost, reliability of customer service, adoption of smart grid technologies, and support for alternative energy;¹²⁶ (2) support for utility investment in smart-grid technologies to improve optionality for customers;¹²⁷ (3) on-bill financing by the utility to enable customers to finance energy efficiency measures;¹²⁸ (4) utility system upgrades to facilitate microgrids;¹²⁹ (5) facilitating deployment of electric vehicles;¹³⁰ and (6) necessary changes to the regulatory model to ensure that utilities remain financially viable even though less electricity is delivered.¹³¹ The report acknowledged that the pilot “anticipates a significant change in the business model for Maryland’s utilities,” thereby requiring a number of “parallel changes” in the regulatory framework.¹³²

122. *Id.*

123. *Id.*

124. *Id.*

125. STAFF OF THE ENERGY FUTURE COAL., *UTILITY 2.0 PILOTING THE FUTURE FOR MARYLAND’S ELECTRIC UTILITIES AND THEIR CUSTOMERS* (2013), available at <http://cleanenergytransmission.org/uploads/Utility%202-0%20Pilot%20Project-reduced.pdf>.

126. *Id.* at 2.

127. *Id.* at 2–3.

128. *Id.* at 3.

129. *Id.*

130. *Id.* at 4.

131. *Id.* at 1, 36.

132. *Id.* at 36. The Maryland PSC, for example, would have to develop metrics for the performance parameters in order to implement the incentives. *Id.* PSC approval would also be required for the on-bill financing, utility investments in smart-grid technology, as well as regulatory changes to accommodate microgrids. *Id.* at 36–37.

In February 2014, then-Governor O’Malley established a separate task force to examine the grid resiliency that could be achieved through microgrids.¹³³ In June 2014, the *Maryland Resiliency Through Microgrids Task Force Report* was issued, and contained a number of recommendations regarding deployment of microgrids in Maryland.¹³⁴ The report identified “public purpose microgrids,” which serve critical community assets that could provide broad public benefits when the utility grid is experiencing an outage.¹³⁵ In the short-term, the report recommended that Maryland focus on utility-owned public purpose microgrids through advocacy and incentives, with long-term efforts focused on reducing barriers to entry for third parties (i.e., non-utilities, such as local governments or private developers) to be able to offer microgrid services.¹³⁶ The Task Force concluded that allowing competition for microgrid services would encourage innovation, provide increased resilience and reliability of electric service, and still allow utilities to operate under “this new business model.”¹³⁷

F. Minnesota’s “e21 Initiative”

In Minnesota, the Great Plains Institute is commencing an unofficial process—the “e21 Initiative”—to explore a new regulatory framework that is intended to align utility and customer interests, regulatory incentives, and rates with state policies promoting renewable energy and a low-carbon future.¹³⁸ As part of the process, the e21 Initiative is convening a broad group of stakeholders including utilities (Xcel Energy and Minnesota Power), an academic institution (George Washington University Law School), an NGO (Center for Energy and Environment), a Minnesota PUC commissioner, and other regulatory observers.¹³⁹ Phase I of the process will focus on alignment of business strategies, regulatory incentives and rates, while Phase II will examine the statutory and regulatory framework.¹⁴⁰ Phase III will involve implementation of the business model and regulatory framework.¹⁴¹ Among the goals of the new regulatory framework is the

133. MD. ENERGY ADMIN, MARYLAND RESILIENCY THROUGH MICROGRIDS TASK FORCE REPORT i (2014), available at http://energy.maryland.gov/documents/MarylandResiliencyThroughMicrogridsTaskForceReport_000.pdf.

134. *Id.*

135. *Id.*

136. *Id.* at i–ii.

137. *Id.* at ii.

138. *e21 Initiative*, GREAT PLAINS INSTITUTE, <http://www.betterenergy.org/projects/e21-initiative>.

139. *Id.*

140. *Id.*

141. *Id.*

development of a viable utility business model that supports integration of DG resources, energy efficiency and advanced energy technology while still providing reasonable rates of returns for utilities.¹⁴² Another goal of the initiative is to align utility and customer interests as Minnesota pursues a goal of reducing greenhouse gas (GHG) emissions 80% by 2050.¹⁴³

IV. POSSIBLE APPROACHES TO THE UTILITY BUSINESS MODEL

As discussed in the following sections, state regulators may consider a number of possible structures for the utility business model in responding to these changing dynamics in the retail electric utility industry. One approach, described as “business as usual,” modifies utility rate structures in an attempt to protect the utility’s existing business model.¹⁴⁴

Another approach, adopted by the New York PSC in its REV proceeding, is to move toward a business model where the foundational utility service is that of a distribution system platform provider, or DSP, which would take the utility out of the business of producing energy and providing demand-side services in favor of facilitating those functions being provided by third parties.¹⁴⁵ Adopting a DSP model raises the further question of deciding whether the incumbent utility will become the DSP, and how the “market power” issues associated with that function can be addressed. The sections that follow present three possible approaches to reduce or eliminate the market power of the incumbent utility: functional unbundling, under which DSP functions are separated without formal changes in legal ownership or corporate structure;¹⁴⁶ ownership unbundling, under which a separate legal entity is formed that would own and operate the distribution system;¹⁴⁷ or creating an independent, third-party DSP that would *operate* the distribution system while leaving the *ownership* of the network in the hands of the incumbent utility.¹⁴⁸

142. *Id.*

143. *Id.*

144. *See infra* Section IV.A.

145. *See infra* Section IV.B.

146. *See infra* Section IV.B.1.

147. *See infra* Section IV.B.2.

148. *See infra* Section IV.B.3.

A. “Business as Usual”

One approach available to regulators is to realign utility rates in an attempt to protect the existing business model. The rate filings of three investor-owned utilities in Wisconsin best illustrate this approach. The utilities sought to modify the structure of their rates in response to the increasing threat posed by DG resources (solar PV in particular).¹⁴⁹ All three utilities proposed an increase to the customer (or basic) charge component of the utility bill to recover a higher percentage of fixed costs.¹⁵⁰ We Energies proposed an increase in the customer charge from \$9 to \$16 per month—a 78% increase—while Madison Gas & Electric and Wisconsin Public Service proposed increases of 81% and 140%, respectively, in the customer charge portion of the bill.¹⁵¹

In decisions issued in November 2014, the Wisconsin Public Service Commission (PSC) largely approved the requested increases in customer charges. Wisconsin Public Service was authorized to increase its monthly

149. Jeffrey Tomich, *Wis. Emerging as Next Battleground in Debate over Future of Solar*, ENERGYWIRE, July 24, 2014.

150. *Id.*

151. Jeffrey Tomich, *Wis. Utilities, Opponents Unwilling to Back Down in Rate Disputes*, ENERGYWIRE (Oct. 8, 2014). We Energies, the state’s largest utility with 1.1 million customers, also proposed to (1) make net metering tariffs less profitable for self-generators, (2) deny net metering for customers who lease solar systems, and (3) impose a demand charge for customers that self-generate. Tomich, *supra*, note 149; *Understanding Your Electricity Charges*, PACIFIC POWER, <https://www.pacificpower.net/bus/ayu/uyec.html> (last visited Mar. 15, 2015). (“Sometimes called a power charge, demand charge is measured in kilowatts (kw). This is a measurement of capacity or the rate at which you use energy. Demand represents the greatest amount of energy used in 15-minute intervals during a billing cycle. To measure demand, electric meters record the average demand usage over each 15-minute period and record the highest (peak) period for the month.”). In proposing the changes in rate structure, We Energies claimed that existing rates for DG resources prevent it from fully recovering its fixed costs, inasmuch as a majority of the fixed costs are recovered through energy, or commodity rates. Tomich, *supra*, note 149. As an example, Wisconsin Public Service claimed that its fixed costs of providing service to residential customers was \$66 per month, as compared to its proposed \$19 per month customer charge. As a result, the fixed costs not recovered through the customer charge are allocated to energy charges and, when DG customers use less energy as a result of solar generation, the utility may fail to recover the fixed costs associated with serving that customer. Jeffrey Tomich, *Wis. PSC Makes Statement with Fixed-Charge Decision*, ENERGYWIRE (Nov. 10, 2014). The solar industry views the proposed demand charge as a “tax” on solar that substantially reduces the profitability of solar panels. Tomich, *supra* note 149. One observer claimed that the proposed demand charge represented a 30% reduction to the return on a typical 6-kilowatt residential solar system, *id.* One representative from the solar industry referred to the We Energies rate proposals as “the most punitive anti-solar rules that would exist anywhere in the country.” Tomich, *supra* note 149.

customer charge from \$9 to \$19, an increase of 111%.¹⁵² The PSC also approved We Energies' requested increase from \$9 to \$16 per month, an increase of 78%, although it rejected the proposal to bar net metering customers from leasing their solar panels.¹⁵³ In the case of Madison Gas & Electric, the PSC approved an 82% increase in the monthly customer charge, from \$10.44 to \$19.¹⁵⁴ In the case of all three utilities, the increase in customer charges was accompanied by slight decreases in the energy charges.¹⁵⁵

Increasing the customer charge portion of the bill and adding a demand charge component to the bill are legitimate tools that utilities can use to attempt to reduce the extent to which fixed costs are recovered through energy charges. When fixed costs are recovered through energy charges, the utility may generate insufficient revenue to cover these costs if customers use less energy, whether as a result of investments in energy efficiency measures or customer-sited DG resources.¹⁵⁶ A disadvantage of increasing the customer charge, however, is the disproportionate impact on small users, such as apartment dwellers and the elderly, who will face substantial increases in their monthly bills.¹⁵⁷ Increasing customer charges

152. Jeffrey Tomich, *Wis. PSC Makes Statement with Fixed-Charge Decision*, ENERGYWIRE, (Nov. 10, 2014), <http://www.eenews.net/energywire/2014/11/10/stories/1060008631>.

153. Thomas Content, *Regulators Agree to Increase Fixed Charge on We Energies Electric Bills*, MILWAUKEE JOURNAL SENTINEL (Nov. 14, 2014), available at <http://www.jsonline.com/business/psc-begins-consideration-of-we-energies-rate-hike-plan-b99390765z1-282726581.html>.

154. Thomas Content, *Regulators Approve Higher Fixed Charges on Madison Gas & Electric Customers*, MILWAUKEE JOURNAL SENTINEL (Nov. 26, 2014), available at <http://www.jsonline.com/business/regulators-approve-higher-fixed-charges-on-madison-gas-electric-customers-b99398472z1-284004991.html>.

155. *Id.*

156. Ben Foster et al., *The 2012 State Energy Efficiency Scorecard*, AM. COUNCIL FOR AN ENERGY EFFICIENT ECON. (Oct. 2012), available at <http://aceee.org/files/pdf/fact-sheet/e12c-es.pdf> (In the case of reduced energy consumption as a result of energy efficiency, a ratemaking mechanism, revenue decoupling, is commonly used to address the issue of fixed cost recovery for the utility. "Decoupling—the disassociation of a utility's revenue from its sales—makes the utility indifferent to decreases or increases in sales, removing what is known as the 'throughput incentive.' Although decoupling does not necessarily make the utility more likely to promote efficiency programs, it removes the disincentive for it to do so.")

157. Jeffrey Tomich, *Wis. Utilities, Opponents Unwilling to Back Down in Rate Disputes*, ENERGYWIRE (Oct. 8, 2014), available at <http://www.eenews.net/energywire/2014/10/08/stories/1060007062> [hereinafter Tomich 2014]. The customer charge component

also dampens incentives to use electricity more efficiently and to conserve, inasmuch as actions taken to reduce energy usage will have a smaller impact on the total bill.¹⁵⁸

Moreover, large energy users will benefit from these changes in rate structure, given the corresponding reduction in energy charges.¹⁵⁹ Lower charges for energy also make investments in DG resources less profitable, as they lengthen the payback period for such investments.¹⁶⁰ More fundamentally, this realignment of utility rates fails to address the long-term, underlying forces at play in the electric utility industry.¹⁶¹

B. Distribution System Platform (DSP) Model

As noted above, the New York PSC's April 2014 *REV Order* articulated a new business model for the electric distribution system based on the concept of a "distribution system platform provider," or DSP¹⁶² The accompanying Staff Report and Proposal identified the functions to be performed by the DSP, as discussed above. Apart from this redefinition of the basic utility function as a DSP, a more fundamental question is determining which entity should perform this DSP function, and the necessary regulatory parameters to ensure that the distribution system platform is operated in a manner that achieves the public policy objectives of, among other things, redesigning the distribution system to take full advantage of DG resources and energy efficiency, stimulating participation and innovation by third parties, and empowering customers to optimize their energy usage.¹⁶³ As described by one industry expert, allowing the

of the bill could be increased substantially and, in the case of small users, this increase is not offset by the corresponding reduction in energy charges.

158. Seth Nowak, *Some Utilities are Rushing to Raise Fixed Charges. That Would Be Bad for the Economy and Your Utility Bill*, AMERICAN COUNCIL FOR AN ENERGY EFFICIENT ECONOMY (Dec. 4, 2014), available at <http://www.aceee.org/blog/2014/12/some-utilities-are-rushing-raise-fixed>. With a lower cost per kilowatthour (kWh) consumed, there is a weaker price signal to conserve. On this point, the Kansas Corporation found that increased fixed charges would result in increased electricity use by 1.1 to 6.8%. *Id.*

159. Tomich 2014, *supra* note 157.

160. *Id.* A DG resource (for example, solar panel) essentially displaces electricity that would otherwise be provided the utility. If the utility charges a lower price per kWh, because more of its costs are recovered through the customer or demand charges, then the output from the solar panel becomes less valuable to the customer. In other words, it takes longer for the utility customer to recover the cost of the solar panel.

161. As discussed in Section II.A. *supra*, the cost of solar PV has declined dramatically in recent years and the trend towards increased penetration of PV is expected to continue. As solar PV costs approach "grid parity" in many parts of the country, customers will increasingly reduce their reliance on the utility grid, thereby threatening the utility business model to an extent incapable of being protected through changes in rate structures.

162. REV ORDER, *supra* note 12, at 31.

163. *Id.* at 2–3.

existing distribution utility to continue to operate the distribution platform under this new utility business model would present “a strong conflict of interest,” given that expanding and optimizing the deployment of customer-owned DG resources and promoting energy efficiency and DR programs may have the effect of reducing the need for the utility to make additional investments.¹⁶⁴ In other words, the utility as DSP would have strong motivation to increase its assets—the rate base upon which it earns a return—rather than promote customer-owned DG resources.¹⁶⁵

FERC examined similar issues in its restructuring of the electric wholesale markets when it issued its Notice of Proposed Rulemaking (NOPR) in April 1995 in its “open access” proceeding.¹⁶⁶ At the conclusion of this rulemaking in 1996, FERC ultimately issued its Order 888, which opened up the electric transmission system to competition.¹⁶⁷ The objective in that proceeding was removing impediments to competition in the wholesale power markets; FERC identified “market power through the control of transmission” as the “single greatest impediment to competition.”¹⁶⁸ FERC concluded in its *Open Access NOPR* that transmission service is a natural monopoly, and transmitting utilities own the transmission system necessary to facilitate bulk power transactions.¹⁶⁹ The owner or controller of transmission facilities has the ability to exclude generation competitors from the market, and thereby favor their own generation.¹⁷⁰ The exclusion can occur through denial of transmission access, or providing access only on rates, terms or conditions of service that are discriminatory.¹⁷¹ Specifically, FERC found that:

164. Herman Trabish, *Utilities Should Not Operate the Distribution Grid*, UTILITYDRIVE, (Aug 15, 2014), <http://www.utilitydive.com/news/jon-wellinghoff-utilities-should-not-operate-the-distribution-grid/298286/> [hereinafter Trabish 2014]. Jon Wellinghoff was Chairman of FERC from 2009 to 2013, and is currently a partner in the law firm of Stoel Rives LLP. See <http://www.stoel.com/jwellinghoff>.

165. *Id.*

166. FERC Docket No. RM95-8-000, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities, 60 Fed. Reg. 17662-01 (Apr. 7, 1995) [hereinafter OPEN ACCESS NOPR].

167. Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, 61 Fed. Reg. (Apr. 24, 1996) (to be codified at 18 C.F.R. pt. 35, 385) [hereinafter ORDER 888].

168. OPEN ACCESS NOPR, *supra* note 155, at 17664.

169. *Id.* at 17665.

170. *Id.* at 17664–65.

171. *Id.* at 17665.

[U]tilities owning or controlling transmission facilities possess substantial market power; that, as profit maximizing firms, they have and will continue to exercise that market power in order to maintain and increase market share, and will thus deny their wholesale customers access to competitively priced electric generation; and that these unduly discriminatory practices will deny customers the substantial benefits of lower electricity prices.¹⁷²

The solution, according to FERC, was to require all public utilities owning or controlling transmission facilities to offer open, fair and non-discriminatory access to the transmission grid.¹⁷³

Citing circumstances strikingly similar to today's situation in the retail distribution system, FERC referred to the industry as "in transition," and then in the process of responding to changes in law, technology and markets.¹⁷⁴ While the move to competitive markets in generation would "fundamentally change long-standing regulatory relationships," FERC stated that the transition to competitive bulk power markets would ultimately fulfill the Commission's goal of encouraging lower electricity rates.¹⁷⁵

In the *Open Access NOPR* and in *Order 888*, FERC identified three possible approaches to address the issue of transmission market power by public utilities. The first was functional unbundling, or requiring utilities to separate wholesale generation and transmission services without formal changes in legal ownership or corporate structure.¹⁷⁶ The second was ownership unbundling (i.e., requiring separation of transmission functions through creation of a separate corporate affiliate, or selling off assets to a non-affiliate (divestiture)).¹⁷⁷ The third was independent ownership of the transmission grid, such as through creation of independent system operators, or ISOs, to operate the transmission grid.¹⁷⁸ As noted above, the same range of options exists today for policymakers to evaluate the "utility 2.0" business model, i.e., determining the best approach for addressing the market power issues associated with utility operation of the distribution system platform, and ensuring nondiscriminatory access to the network for all market participants. The following three sections describe these three models, and their potential application in the restructuring of the traditional distribution utility.

172. *Id.*

173. *Id.*

174. *Id.* at 17663.

175. *Id.*

176. ORDER 888, *supra* note 167, at 58.

177. *Id.* at 60; OPEN ACCESS NOPR, *supra* note 166, at 17681.

178. ORDER 888, *supra* note 167, at 61.

1. DSP Model with Functional Unbundling

In its *Open Access NOPR* and *Order 888*, FERC determined that functional unbundling was necessary to accomplish non-discriminatory open access to the transmission system.¹⁷⁹ FERC defined functional unbundling to have three elements. First, the public utility must take transmission services (and related ancillary services, such as scheduling and balancing) for its own needs under the same tariff under which others take such services.¹⁸⁰ In other words, the utility charges itself the same price for those services that it charges its wholesale transmission customers.¹⁸¹ The second element was a requirement that rates for transmission and ancillary services must be unbundled, or separately stated.¹⁸² The third element was that the utility must rely on the same electronic network as its transmission customers when it seeks to obtain information about transmission availability for purposes of buying and selling power.¹⁸³ Apart from these three elements, FERC imposed a strong code of conduct regarding communications between a utility's merchant function (buying and selling of power) and transmission operations.¹⁸⁴ The code of conduct proposed by FERC required that employees in transmission system functions be separated from those in wholesale marketing functions, and also defined permissible and impermissible contacts between these groups of employees.¹⁸⁵

In *Order 888*, FERC determined that functional unbundling was a “reasonable and workable means” of addressing the issue of non-discriminatory access, and declined to adopt the “more intrusive and potentially more costly mechanism” of ownership or corporate unbundling.¹⁸⁶ FERC also rejected “operational unbundling” (the use of a third-party independent system operator), although it encouraged utilities to consider ISOs “as a tool to meet the demands of a competitive marketplace.”¹⁸⁷ As

179. OPEN ACCESS NOPR, *supra* note 166, at 17681; ORDER 888, *supra* note 167, at 60.

180. OPEN ACCESS NOPR, *supra* note 166, at 17681.

181. *Id.*

182. *Id.*

183. *Id.* ORDER 889, issued April 24, 1996, required an Open Access Same Time Information System, or OASIS, to fulfill this third element of functional unbundling. See FERC Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct, 18 C.F.R. § 37 (1996), available at <http://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-9-00k.txt>.

184. ORDER 888, *supra* note 167, at 59.

185. *Id.*

186. *Id.* at 60.

187. *Id.* at 60, 61.

discussed in a later section of this article, FERC ultimately revisited this determination in *Order 2000*, where it extensively discussed the failures of functional unbundling to achieve the desired goals and moved toward the ISO model as the best means of ensuring nondiscriminatory access to the transmission grid.

In New York's REV proceeding, the Department of Public Service staff (Staff) endorsed a functional unbundling approach in its "Straw Proposal on Track One Issues."¹⁸⁸ As noted above, Staff defined the Distribution System Platform, or DSP, model in its April 2014 report.¹⁸⁹ In the *Track One Proposal*, Staff recommended that the incumbent distribution utility perform the DSP function,¹⁹⁰ accompanied by additional measures to address "the natural monopoly of distribution system operations" and to "prevent the unfair exercise of market power by utilities."¹⁹¹ Staff concluded that there were significant advantages to this structure inasmuch as the utilities already bear the responsibility for the important function of maintaining grid reliability, and the regulatory mechanisms are already in place for the incumbent utilities, including ratemaking, audits and operational review.¹⁹² In its *Track One Order*, the New York PSC agreed with Staff's recommendation, finding that it could be in the "best interests of New York consumers" for the utilities to serve as DSPs under the regulatory authority and supervision of PSC.¹⁹³ The PSC indicated that it would not engage in functional separation of DSP functions from standard utility operations "in a manner that impairs effective performance of the integrated functions of utility and DSP or imposes unnecessary costs."¹⁹⁴

With respect to market power, the *Track One Proposal* cites the utility's "direct commercial market involvement" with distributed energy resources, or DER, as a source of market power, given the utility's control of (1) schedule and dispatch of these resources, (2) their ability to interconnect with the distribution platform, and (3) their access to system and customer data.¹⁹⁵ As a result, the utility could erect barriers to the ability of distributed energy resources to compete, such as through burdensome interconnection

188. TRACK ONE PROPOSAL, *supra* note 13.

189. REV ORDER, *supra* note 12, Att. 1 at 9.

190. TRACK ONE PROPOSAL, *supra* note 13, at 12.

191. *Id.* at 18–19.

192. *Id.*

193. TRACK ONE ORDER, *supra* note 69, at 48. The PSC found it unnecessary to create an independent DSP, given that the associated investment and operating costs would ultimately be passed through to retail customers. *Id.* at 50. According to the TRACK ONE ORDER, the PSC saw "no value in adding to consumer burdens by either creating or imposing these costs on customers." *Id.*

194. *Id.* at 52.

195. TRACK ON PROPOSAL, *supra* note 13, at 67.

requirements, inadequate tariffs, or denial of access to system or customer data.¹⁹⁶ The *Track One Proposal* also refers to the possibility of a “functional competitive advantage” of the platform operator, irrespective of utility behavior.¹⁹⁷

Addressing these market power concerns, the *Track One Proposal* recommended generally that utilities not be permitted to engage directly in ownership of distributed energy resources, unless it is generation or storage located on utility distribution property.¹⁹⁸ While acknowledging that there are advantages to utility involvement in DER—they know the needs and capabilities of the distribution system, and can easily identify the best sites for locating DER—the *Track One Proposal* concluded that allowing utility participation could have the effect of discouraging private capital and potential market participants from investing in New York, thereby stifling the possible growth of a competitive and innovative market for distributed energy resources.¹⁹⁹ The *Track One Proposal* recommended that utilities be permitted to participate directly in sponsorship and management of energy efficiency programs.²⁰⁰ Where an unregulated utility affiliate seeks to operate within the utility’s service territory, codes of conduct would govern the interactions with the regulated utility.²⁰¹ In addition, heightened regulatory scrutiny would monitoring interconnection complaints and making ombudsman available for DER providers.²⁰² If an affiliate bids into a utility’s procurement for distributed energy resources, an independent entity would select the winning bids.²⁰³ Finally, caps on market share would be placed on the extent of affiliate participation within the service territory and within individual distribution circuits.²⁰⁴

196. *Id.* The New York PSC defined DER to include DG resources as well as end-use energy efficiency, demand response and distributed storage. TRACK ONE ORDER, *supra* note 69, at 3.

197. TRACK ONE PROPOSAL, *supra* note 13, at 67.

198. *Id.* at 72. The Track One Proposal would allow direct participation in limited circumstances, if part of a utility’s Distributed System Implementation Plans, and upon a showing that the proposal addresses a substantial system need, the benefits of utility engagement outweigh the market power concerns, and a competitive solicitation is used for construction and operation of DG resources. *Id.* at 72–73.

199. *Id.* at 70.

200. *Id.* at 72.

201. *Id.* at 73.

202. *Id.*

203. *Id.*

204. *Id.*

In its *Track One Order*, the PSC adopted Staff’s recommendations from the *Track One Proposal* and prohibited utility ownership of distributed energy resources where a market participant can and will provide these services.²⁰⁵ The PSC modified Staff’s recommendation by narrowing the circumstances where it would be permissible for the utility to own distributed energy resources. While the *Track One Proposal* would allow utility ownership of energy storage and generation located on utility property, the *Track One Order* found that utility investment should not be permitted simply because of its location on any utility property. Rather, the exemption from the general rule against utility ownership of DER would apply if the resource is “directly integrated into distribution service” and is used to “support and enhance reliable system operations.”²⁰⁶

Section V.B. below will discuss some of the advantages and disadvantages of the functional unbundling approach relative to other possible structures.

2. DSP Model with Ownership Unbundling

As noted above, FERC considered the possibility of ownership unbundling for transmission in its *Open Access NOPR* and *Order 888*, but ultimately adopted a rule requiring functional unbundling rather than “corporate unbundling,” or the creation of a separate corporate entity to own and operate a utility’s transmission assets.²⁰⁷ While *Order 888* accommodates ownership unbundling, it does not require it.²⁰⁸ FERC concluded in *Order 888* that ownership unbundling would create inefficiencies and additional costs, which was unnecessary given its conclusion that functional unbundling would be sufficient to remedy discriminatory practices.²⁰⁹ *Order 888* therefore rejected ownership unbundling as a “more intrusive and potentially more costly mechanism.”²¹⁰

205. TRACK ONE ORDER, *supra* note 69, at 52, 68–70.

206. *Id.* at 69.

207. OPEN ACCESS NOPR, *supra* note 166, at 17681.

208. *Id.*

209. ORDER 888, *supra* note 167, at 54. FERC acknowledged in ORDER 888 that a number of commenters strongly advocated for corporate or ownership unbundling. *Id.* at 56–58. One commenter noted the affiliate abuses that were occurring in the natural gas industry, and claimed that the potential was even greater in the electric industry given the domination by vertically integrated utilities. *Id.* at 56. Another commenter criticized functional unbundling as insufficient as it would fail to address the ability of the utility to favor its marketing operations when dealing with issues related to transmission planning, capital investment, and O&M replacement costs. *Id.*

210. *Id.* at 60.

Under the ownership unbundling model, the operation of the electricity network is effectively separated from generation and retail activities.²¹¹ In other words, the previously common ownership structure between network operations and generation activities of a company are separated, including the separation of asset ownership.²¹² The separate transmission company that is created not only operates, but also owns, the transmission network assets.²¹³ Generation companies would be precluded from acquiring or maintaining transmission networks.²¹⁴

An example of an “ownership unbundled” approach for transmission is the independent transmission system operator, or ITSO, where one legal entity both owns and operates the transmission system.²¹⁵ One such entity is National Grid in the United Kingdom, which owns and operates the national transmission network.²¹⁶ In addition to the system operator in the UK, there are three transmission operators charged with developing, operating and maintaining the transmission grid within defined regions: National Grid Electricity Transmission plc (NGET) in England and Wales, Scottish Power Transmission Limited for southern Scotland, and Scottish Hydro-Electric Transmission plc for northern Scotland and the Scottish islands.²¹⁷

Section V.C. below will discuss some of the advantages and disadvantages of the ownership unbundling approach relative to other possible structures.

3. *Third-Party, Independent Distribution System Operator*

This possible approach is based on the current structure of the regional wholesale markets, pursuant to FERC Order 2000, which places operation of the regional transmission markets in the hands of independent, third-party operators. Under this model, ownership is separated from operation:

211. Neelie Kroes, *Improving Competition in European Energy Markets Through Effective Unbundling*, 31 *FORDHAM INT’L L.J.* 1387, 1424 (2007) (defining ownership unbundling) [hereinafter Kroes].

212. *Id.* at 1425.

213. *Id.*

214. *Id.*

215. Michael Pollitt, *Lessons from the History of Independent System Operators in the Energy Sector*, *ENERGY POLICY* 47, at 4 (2012) [hereinafter Pollitt 2012].

216. National Grid, *What We Do in the Electricity Industry*, available at <http://www2.nationalgrid.com/uk/our-company/electricity/>.

217. OFFICE OF GAS AND ELECTRICITY MARKETS (OFGEM), *Electricity, The GB Electricity Transmission Network*, available at <https://www.ofgem.gov.uk/electricity/transmission-networks/gb-electricity-transmission-network>.

While utilities may continue to *own* transmission assets, the regional transmission organizations (RTOs) or independent system operators (ISOs) *operate* the grid.²¹⁸ This ensures that the transmission owners have no ability to leverage their monopoly power in the transportation market—by virtue of ownership of the transmission network—to gain an advantage in their positions in the commodity or power market.

A leading proponent of this model, sometimes referred to as the Independent Distribution System Operator in the context of retail distribution services, or IDSO, model, is Jon Wellinghoff.²¹⁹ In Wellinghoff's view, the traditional utility model is “increasingly out of sync” with current trends in the electricity markets and the expanding penetration of DG resources.²²⁰ Wellinghoff's approach starts with the perceived need for a fundamental reform and a re-examination of the way that utilities recover costs; he identified those services that are best delivered in a regulated monopoly environment versus those that can be provided under competition.²²¹ He concludes that the solution is to let the utility continue to *own* the grid, while an “objective and separate” IDSO (independent distribution system operator) would *operate* the distribution platform.²²² Under this model, the IDSO would be responsible for the reliability of the distribution system and, like the ISO at the wholesale level, would ensure open, fair and nondiscriminatory access to the distribution platform.²²³ The IDSO would also be charged with developing necessary market mechanisms and optimizing the deployment of DG resources.²²⁴ Unlike the wholesale ISO model, where the ISO is regulated by FERC, the IDSO would be subject to the jurisdiction of state PUCs.²²⁵

The distribution utility would continue to be responsible for maintaining the distribution platform, subject to traditional rate-of-return regulation by state PUCs, and would thereby be permitted to earn a return on any additional investments in the distribution system.²²⁶ The distribution utility would also continue to maintain the customer relationship with end users (including the billing function).²²⁷ Under this model, the distribution

218. Federal Energy Regulatory Comm'n, 18 C.F.R. pt. 35, at 235 (1999) *available at* <http://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf>.

219. Wellinghoff was Chairman of FERC from 2009 to 2013, and is currently a partner in the law firm of Stoel Rives LLP. *See* Jon B. Wellinghoff, *Attorneys*, STOEL RIVES LLP, <http://www.stoel.com/jwellinghoff>.

220. Tong and Wellinghoff, *supra* note 153, at 4.

221. *Id.* at 4.

222. *Id.* at 2.

223. *Id.*

224. *Id.*

225. *Id.*

226. *Id.*

227. *Id.*

utility would benefit from having a much simpler (and less risky) business model, more efficient cost recovery, and the ability of its unregulated affiliates to offer competitive services (e.g., investing in DG resources) in areas outside of its service territory.²²⁸ Wellinghoff identifies the following benefits to the IDSO model: more effective and efficient integration of DG resources, increased utilization of the existing grid, more opportunities for consumer choice and participation, and stimulating the development of a “Transactive Energy Framework” that would accommodate commerce in energy services.²²⁹

The *Track One Proposal* in New York’s REV proceeding rejected the recommendation to establish an independent DSP.²³⁰ The *Proposal* acknowledged several advantages to the independent DSP, such as the ability to establish uniform, statewide practices (in contrast to the DSPs operated by individual utilities), and avoidance of market power issues regarding utility ownership of distributed energy resources.²³¹ Moreover, an independent DSP may be more effective at stimulating technological innovation.²³² The *Track One Proposal* also identified “numerous drawbacks” to an independent DSP, however, including the addition of significant redundant costs given that the DSP would perform many of the functions currently performed by utilities, and the addition of duplicative functions at the DSP with respect to the system planning and operations functions of the utilities.²³³ The *Track One Proposal* concluded that use of an independent DSP approach would be an “expensive, unwieldy, and incomplete response.”²³⁴ As noted above, the New York PSC in its *Track One Order* largely adopted this analysis, finding that there would be “no value in adding to consumer burdens” the costs associated with creating an independent DSP.²³⁵

Section V.C. below will discuss some of the advantages and disadvantages of the third-party, independent system operator approach relative to other possible structures.

228. *Id.* at 2–3.

229. *Id.* at 2

230. TRACK ONE PROPOSAL, *supra* note 13, at 19.

231. *Id.*

232. *Id.*

233. *Id.*

234. *Id.* at 21.

235. TRACK ONE ORDER, *supra* note 69, at 50.

V. LESSONS LEARNED FROM PREVIOUS INDUSTRY RESTRUCTURINGS

This section discusses the actual experience under the various business models, based on previous initiatives to restructure the electric utility industry both in the United States and Europe. The subsequent sections discuss functional unbundling, where FERC's experience under *Order 888* and subsequent issuance of *Order 2000* provide some guidance on the success of this business model in addressing market power issues. The European Union also has experience with a business model based on functional unbundling, and a number of EU member nations have recently moved to an ownership-unbundled model, thereby providing some basis for comparison. With respect to the independent, third-party ownership structure, the seven RTOs currently operating in the U.S. provide some basis upon which to evaluate the success of that model.

A. Functional Unbundling

1. FERC's Restructuring of the Electric Wholesale Markets

As noted above, FERC's *Order 888* was intended to promote competition in the wholesale electricity markets by removing impediments arising largely from the exercise of market power by transmission owners over the interstate transmission grid.²³⁶ In addition to requiring all public utilities owning or controlling transmission facilities to offer open, fair and non-discriminatory access to the transmission grid, *Order 888* attempted to deal with the market power issue by requiring functional unbundling.²³⁷ The functional unbundling requirements included, among other things, the separation of transmission system functions and staffs within a public utility from wholesale generation marketing functions and staff, and abiding by codes of conduct that defined impermissible contacts between transmission and generation personnel.²³⁸

Within four years, however, FERC issued its Notice of Proposed Rulemaking on Regional Transmission Organizations, and concluded that functional unbundling had largely failed to achieve the goal of eliminating opportunities for transmission owners to unduly discriminate in the operation of their transmission systems in order to favor the power marketing activities of their affiliates.²³⁹ As stated in the *RTO NOPR*, "there are indications that continued discrimination in the provision of

236. ORDER 888, *supra* note 167.

237. OPEN ACCESS NOPR, *supra* note 166, at 17681; ORDER 888, *supra* note 167, at 60.

238. Regional Transmission Organizations; Notice of Proposed Rulemaking, 64 Fed. Reg. 31390-01 (June 10, 1999) [hereinafter RTO NOPR].

239. *Id.* at 31397.

transmission services by vertically integrated utilities may . . . be impeding fully competitive electricity markets.”²⁴⁰

FERC acknowledged that utilities exercising monopoly power over transmission facilities (while also having power marketing interests) have “poor incentives” to provide adequate transmission services to their power marketing competitors and, in fact, it is in their economic self-interest to frustrate their competitors in favor of their own power marketing operations.²⁴¹ Fundamentally, functional unbundling did nothing to change these incentives, but attempted to minimize the ability of the transmission-owning utilities to act on those incentives.²⁴² FERC proceeded to identify the continued discriminatory conduct by transmission owners that represent remaining impediments to competition.²⁴³ More generally, the *RTO NOPR* expresses concern about the “extensive regulatory oversight and administrative burdens” associated with enforcement of the standards of conduct.²⁴⁴ On this point, the *RTO NOPR* states:

[A] system that attempts to control behavior that is motivated by economic self-interest through the use of standards of conduct will require constant and extensive policing. This kind of regulation goes beyond traditional price regulation and forces us to regulate very detailed aspects of internal company policy and communication. For functional unbundling to be successful, we have to be concerned, in some sense, about ‘who spoke to whom’ in the company cafeteria. Functional unbundling does not necessarily promote light-handed regulation. It also imposes a cost on those entities that have to comply with the standards of conduct who face additional training and rules that create rigidities in their internal management activities.²⁴⁵

The *RTO NOPR* also noted the implications of continued allegations of discrimination by the transmission owners. First, there is the challenge of

240. *Id.* at 31391.

241. *Id.* at 31402. FERC acknowledged the views of some that functional unbundling cannot be expected to eliminate efforts by transmission owners to gain an economic advantage, particularly considering that investor-owned utilities have an obligation to maximize shareholder value, *id.*

242. *Id.*

243. *Id.* The discriminatory conduct included the pattern of transmission owners to understate the available transmission capacity (ATC) on paths valuable to competitors, or to divert capacity so that it is available for use by affiliated power marketing interests, *id.* at 31403; violations of standards of conduct, which indicate a failure of functional separation, *id.* at 31405–06; discrimination in implementing line loading relief, *id.* at 31406, and OASIS sites that are difficult to use, *id.*

244. *Id.* at 31406.

245. *Id.* at 31407.

detecting such conduct, the inefficiency of the complaint process, and the insufficiency of any penalties in providing a deterrence.²⁴⁶ More fundamentally, the *RTO NOPR* expresses the concern that such allegations represent a perception by market participants that the market is not operating fairly, given that the integrated utilities have the incentive and continued opportunity to discriminate.²⁴⁷ This fear of an unfair advantage may inhibit the willingness of market participants to invest in the market, thereby jeopardizing the development of robust competition.²⁴⁸ As stated in the *NOPR*, this “perception that many entities that operate the transmission system cannot be trusted is not a good foundation on which to build a competitive power market” in that it “creates uncertainty and risk for new investments in generation.”²⁴⁹

In its *Order 2000*, issued six months later, FERC adopted a final rule that required public utilities to make various filings geared toward the formation of regional transmission organizations.²⁵⁰ Because such organizations included “minimum characteristics” requiring their independence from transmission owners, FERC determined that RTOs could remove remaining opportunities for discriminatory transmission practices.²⁵¹ In contrast to the heavy policing required under functional unbundling, FERC expressed the view that “a properly structured RTO would reduce the need for Commission oversight and scrutiny,” thereby benefitting both FERC and the industry.²⁵² Because the RTO would be independent of any power marketing interests, FERC would no longer be required to monitor and enforce compliance with standards of conduct effecting functional unbundling.²⁵³

2. Experience in the European Union

Electricity Directives issued by the European Union in 2003 required functional unbundling by directing that transmission owners separate their

246. *Id.* at 31403.

247. *Id.*

248. *Id.*

249. *Id.* at 31406.

250. Federal Energy Regulatory Comm’n, 18 C.F.R. pt. 35 (1999), available at <http://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf> at 1.

251. *Id.* at 3. Order 2000 requires that all RTOs be independent of any market participants. *Id.* at 152. Independence is satisfied by (1) the RTO, its employees, and any non-stakeholder directors not having any financial interest in any market participants; (2) the RTO having a decision-making process that is independent of control by any market participant; and (3) the RTO having exclusive and independent authority to file changes to its transmission tariff with FERC. *Id.* at 152–53.

252. *Id.* at 96.

253. *Id.*

transmission management and information functions from other aspects of the vertically integrated utility.²⁵⁴ In other words, while there was no required separation in the ownership of assets between the transmission system and the vertically integrated utility, management unbundling and information unbundling—through the use of “information barriers between supply and network activities”—was intended to avoid discrimination in the operation of the transmission system.²⁵⁵ In 2005, the European Commission commenced a Sector Inquiry to examine the gas and electricity sectors, resulting in a Final Report issued in January 2007.²⁵⁶ That Report generally found a failure of functional unbundling inasmuch as incentives for preferential treatment within the integrated utility remained, due to the “inherent conflict of interest” when vertical integration of grid operation is combined with generation and/or retail sales.²⁵⁷ As concluded by one observer, “incumbent suppliers view their networks as strategic assets that serve their commercial interests” in generation and/or retail sales.²⁵⁸ The functional unbundling regime results in a “high risk” that the network operator will either engage in anti-competitive behavior or operate the network in a sub-optimal fashion.²⁵⁹ In addition, the fear that the network operator will not treat market participants fairly was perceived to have a “chilling effect” on third parties investing in the marketplace.²⁶⁰

The Final Report found three types of discriminatory practices by network operators against market participants. First, there is the ability to grant preferential treatment to their affiliates, through such tactics as not making unused capacity available, complicating the interconnection process, or charging high balancing fees.²⁶¹ The second practice is referred to as “information leakage,” where “Chinese walls” are violated by information that is exchanged between the system operator and the competitive activities of its affiliates.²⁶² Another example is the ability of top management of a

254. Kroes, *supra* note 211, at 1394.

255. *Id.*

256. *Id.* at 1402 (citing Commission of the European Communities, Communication from the Commission, Inquiry Pursuant to Article 17 of Regulation (EC) No. 1/2003 into the European Gas and Electricity Sectors (Final Report), COM (2006) 851 Final (Jan. 2007)).

257. Kroes, *supra* note 211, at 1405.

258. *Id.*

259. *Id.* at 1406.

260. *Id.*

261. *Id.* at 1406–07. It should be noted that these activities may be difficult to detect, even by an experienced regulatory agency. *Id.* at 1406.

262. *Id.* at 1407–08.

generating company, represented at the parent level of the corporate organization, having access to strategic business information of the network operator.²⁶³ In addition, some central functions, such as legal services, are provided across the affiliated group of companies, providing opportunities for access to information that is not available to third-party market participants.²⁶⁴ Third, the incentives driving investment decisions remain distorted, with bias in favor of meeting the needs of generating affiliates rather than investing in infrastructure that might enable additional competition.²⁶⁵ As stated by one observer, “[t]he interest in protecting the market power and profitability of their [generating] business trumps the interest in increasing (regulated) network business.”²⁶⁶ An over-arching issue with respect to all three practices relates to the difficulty encountered by regulators in enforcing the functional unbundling requirements, due to insufficient resources, a lack of monitoring, and lack of authority.²⁶⁷

B. Relevant Experience with Ownership Unbundling and Independent RTO Approaches

The various approaches for achieving the separation of the transmission function have been implemented in different electricity markets, and this experience provides some basis for analysis of the advantages and disadvantages of the options for the structure of the industry. The preceding section described the restructuring of the wholesale electricity market in the U.S., and the shortcomings identified by FERC with respect to functional unbundling. Two other options warrant discussion: the independent system operator, as illustrated by RTOs in the U.S., and ownership unbundling, as illustrated by ITSOs in Europe.

With respect to the first approach, FERC’s conclusion in *Order 2000* was that the independent RTO approach, by “cleanly separating the control of transmission from power market participants,” would be effective in reducing opportunities for unduly discriminatory conduct.²⁶⁸ Because the RTO would have no financial interest in any market participant—under the “minimum characteristic” requirement of independence—and no power market participant would be able to control an RTO, the economic incentive—as well as the ability—of the transmission provider to engage in discriminatory practices would be eliminated.²⁶⁹ This approach would

263. *Id.* at 1408.

264. *Id.* at 1408–09.

265. *Id.* at 1409.

266. *Id.*

267. *Id.* at 1410.

268. 18 C.F.R. pt. 35, *supra* note 250, at 90.

269. *Id.*

also eliminate the “mistrust” in current grid management, and thereby attract new participants in the generation market inasmuch as the market will be perceived as more fair and attractive for investment.²⁷⁰ With the addition of more participants, the market can be expected to be deeper and more fluid.²⁷¹

An issue with this approach, as compared with the functional and ownership unbundling approaches, is the cost of implementation. On this point, *Order 2000* suggests that the flexibility permitted in the *Order* would allow for the creation of “streamlined” organizational structures that need not be costly.²⁷² Given the flexibility possible in meeting the minimum characteristics, the admittedly high costs associated with formation of existing ISOs and power exchanges may not be relevant, according to *Order 2000*.²⁷³ In contrast to formation costs, FERC claims benefits from RTO formation of \$2.4 billion to \$5.1 billion annually, which represents 1.1 to 2.4% of the total costs in the electric power industry.²⁷⁴

There is considerable evidence on the costs associated with operating some of the existing RTOs. Seven RTOs currently operate in the U.S.—ISO New England, MidContinent ISO (formerly known as Midwest ISO), PJM Interconnection, Southwest Power Pool, California ISO, New York ISO, and Electric Reliability Council of Texas.²⁷⁵ The MidContinent ISO, the RTO serving all or parts of 15 states in central U.S.,²⁷⁶ has 782 employees and an annual budget of \$273 million.²⁷⁷ PJM, which is the RTO operating in the Mid-Atlantic states, has 725 employees and an annual budget of \$252 million.²⁷⁸ As stated by one commentator, these costs are “non-trivial.”²⁷⁹ Moreover, this commentator expressed the concern that ISOs are “simply bureaucracies that are not subject to any effective cost regulation.”²⁸⁰ He

270. *Id.* at 92–93.

271. *Id.* at 93.

272. *Id.* at 91.

273. *Id.*

274. *Id.* at 95–96.

275. U.S. GOVERNMENT ACCOUNTABILITY OFFICE, *Electricity Restructuring: FREC Could Take Additional Steps to Analyze Regional Transmission Organizations’ Benefits and Performance*, 3 (Sep. 2008), available at <http://www.gao.gov/assets/290/281312.pdf> [hereinafter GAO REPORT].

276. MISO, *Locations*, <https://www.misoenergy.org/AboutUs/Locations/Pages/Locations.aspx>. (last visited Mar. 4, 2015).

277. Pollitt 2012, *supra* note 215, at 37.

278. *Id.*

279. *Id.* at 36.

280. *Id.* at 40.

points to the sharp increases in ISO costs in the U.S. in recent years, and notes that the number of employees at the Southwest Power Pool (SPP) has grown from 39 in 1998 to 131 in 2004 and 473 in 2010.²⁸¹ A former PSC Commissioner in New York complained about the absence of ratepayer participation in the process at RTOs, and noted that the cost per New York resident for services provided by the New York ISO is 41 percent higher than the same figure for the PJM Interconnection.²⁸²

A *GAO Report* also expresses concern about the process for stakeholder participation in RTO decisions that affect electricity prices.²⁸³ It notes the expectation of FERC that RTOs would be subject to lighter regulation, given the requirements set forth in *Order 2000* regarding stakeholder participation.²⁸⁴ As a practical matter, however, the *GAO Report* observed that the stakeholder process is very “resource intensive,” with up to 600 meetings at one RTO open to stakeholder participation in a typical year.²⁸⁵ Stakeholders representing consumers complained that RTOs fail to give adequate consideration on the impact of decisions on electricity prices in their decision-making process,²⁸⁶ and that RTOs place too much emphasis on reliability without considering the availability of lower cost options.²⁸⁷ Consumer groups also expressed concern about the lack of frequent, independent review of RTO expenses and budgets by FERC,²⁸⁸ and FERC giving too much deference to the stakeholder process within the RTOs under the assumption that this process would provide a forum for resolving all concerns.²⁸⁹ One commenter observed that it is because of the diverse nature of ownership and governance in an RTO that market participants may not have the incentive or ability to effectively regulate the RTO’s performance.²⁹⁰ The *GAO Report* concluded that FERC involvement and oversight of RTOs was important, and recommended that FERC regularly review RTO financial reports to ensure that RTO expenses are clearly

281. *Id.*

282. Heather Haddon, *Power of the Purse*, N.Y. POST, Apr. 10, 2011 (Transcript of July 15, 2010 Regular Meeting of the PSC) (Statement of Commissioner Robert Curry at 23), available at <http://nypost.com/2011/04/10/power-of-the-purse/>. (In 2010, New Yorkers paid an average of \$7.16 per person for New York ISO services, as compared with \$5.24 per person for ratepayers within the PJM Interconnection.)

283. GAO REPORT, *supra* note 275, at 6.

284. *Id.* at 58.

285. *Id.* at 6.

286. *Id.*

287. *Id.* at 34.

288. *Id.* at 38.

289. *Id.* at 41.

290. Pollitt 2012, *supra* note 215, at 41.

reported to ensure the “cost-effectiveness” of RTOs and that their rates meet the “just and reasonable” standard under the Federal Power Act.²⁹¹

With respect to the second option—the ITSO model—the experience in Europe provides some guidance on the relative performance of this industry structure, which features an independent transmission system operator that both owns and operates the grid, and is prohibited from investing in electricity generation or providing service to retail customers.²⁹² The ITSO model results in a concentration of ownership of transmission assets, as compared to the “asset-lite” RTO model, where the utilities continue to own the transmission assets even though the network is operated by the RTO.²⁹³ This difference in characteristics means that different options are available for regulating the entities and, more specifically, the availability of incentive mechanisms.²⁹⁴ Because the RTO model is “asset lite,” there are insufficient financial resources within the RTO structure to absorb any significant penalty for under performance.²⁹⁵ The size of the financial penalties may therefore be very low as compared to the negative impacts flowing from under-performance, making performance incentives challenging to design.²⁹⁶

In the case of the ITSO model, however, the concentration of transmission assets results in the financial strength to withstand strong incentive mechanisms.²⁹⁷ National Grid Electricity Transmission, for example, operated under an incentive/penalty mechanism of 1–4% of total revenue that was imposed to provide incentives to reduce congestion on the transmission network.²⁹⁸ This “powerful incentive” would not be available under the RTO model, where the ownership and operation of the transmission grid are not integrated.²⁹⁹ In addition, one commenter has noted that the regulators at the state and national level in the United States lack sufficient experience with the use of incentive mechanisms in regulating the monopoly functions of the electricity system.³⁰⁰ Moreover, given the complexity and the large number of outputs associated with an RTO, it

291. GAO REPORT, *supra* note 275, at 59.

292. Pollitt 2012, *supra* note 215, at 32.

293. *Id.* at 33.

294. *Id.* at 40.

295. *Id.*

296. *Id.*

297. *Id.* at 41.

298. *Id.*

299. *Id.*

300. *Id.*

would be challenging to develop a comprehensive system of metrics to gauge the performance of the RTO's operation.³⁰¹ Another commenter described the regulation and cost control at RTOs as "unsatisfactory" when compared with the use of incentive regulation for ITOs in Europe.³⁰² An additional commenter referred to the risk of RTOs becoming "self-perpetuating bureaucracies" having innate incentives to prevent evolution of the energy toward the ITO structure.³⁰³

Another function of the transmission organization is determining the optimal level of investment in transmission facilities. On this point, RTOs are said to under-invest in transmission because of the multi-jurisdictional nature of the organizations, and the divergence between regional, RTO-wide benefits and the recovery of costs within individual states, where regulators may be unwilling to increase transmission charges to recover the costs.³⁰⁴ As evidence of this, one commenter cites the relatively high congestion costs within the PJM Interconnection, suggesting an under-investment in the transmission system.³⁰⁵ Another commenter, noting the reduced incentives for investing in transmission, refers to RTOs as having an "identity crisis" inasmuch as they "do not have the incentives and motivation of a pure transmission company, nor do they have the competence and responsibility of a public transmission owner."³⁰⁶ Thus, while the independence of RTOs successfully achieves non-discriminatory access objectives, the issue of investment adequacy remains.³⁰⁷

ITOs, on the other hand, are said to have a tendency to over-invest in transmission, given their "clear incentive to inflate estimates of investment requirements,"³⁰⁸ which may result in "potentially excessive expansions in transmission assets."³⁰⁹ At the same time, ITOs are better equipped to achieve an "optimal configuration" through investments in both hardware and software.³¹⁰ RTOs, for their part, have the advantage of being relatively easy to scale up across independently owned transmission systems.³¹¹ In the case of both the RTO and ITO models, strong regulatory oversight

301. *Id.*

302. *Id.* at 47.

303. Kroes, *supra* note 211, at 1399.

304. Pollitt 2012, *supra* note 215, at 46.

305. Michael Pollitt, *The Arguments For and Against Ownership Unbundling of Energy Transmission Networks*, 36 ENERGY POL'Y 704, 711 (2008) [hereinafter Pollitt 2008].

306. Kroes, *supra* note 211, at 1398.

307. *Id.*

308. Pollitt 2012, *supra* note 215, at 46.

309. Pollitt 2008, *supra* note 305, at 711.

310. Pollitt 2012, *supra* note 215, at 47.

311. *Id.* The RTOs currently in operation in the U.S. cover part or all of 35 states and the District of Columbia, and serve over half of the electricity demand. GAO REPORT, *supra* note 275, at 3.

will be necessary to ensure the correct level of investment in the transmission system.³¹²

Available data from the European experience confirm the positive correlation between ownership unbundling and investment in the networks.³¹³ Where the transmission services were provided by an ownership-unbundled operator, data show a “significant and consistent increase in investment levels” following the legal unbundling.³¹⁴ In contrast, the levels of investment are comparatively lower where the transmission services operator is part of a vertically integrated utility.³¹⁵ It should also be noted that investment in the network by ownership-unbundled operators would benefit from a lower cost of capital associated with the network business versus the vertically integrated business.³¹⁶ The less-risky nature of the regulated network business translates into lower capital costs, and thus the costs associated with financing investments in the network will be lower.³¹⁷

Another metric to consider is the impact of the industry structure on electricity prices. Evidence from the European Union suggests that weakening the market power of the vertically integrated utilities—through ownership unbundling, for example—results in lower energy prices.³¹⁸ As part of the Impact Assessment performed for the Commission of European Communities, price trends for nations with and without ownership-unbundled network operators were compared for the period of 1998-2006.³¹⁹ This analysis showed that while electricity prices increased by six percent in those countries with vertically integrated network operators, prices declined by three percent in countries with ownership-unbundled network operators.³²⁰

312. *Id.* at 46.

313. Kroes, *supra* note 211, at 1426.

314. *Id.* at 1426–27. The Sector Inquiry showed that ownership-unbundled system operators reinvested about twice as much of their congestion revenue into the network (33.3%) than the integrated system operators (16.8%). *Id.* at 1427.

315. *Id.* The commenter notes that a vertically integrated transmission service operator has a disincentive to investment in transmission infrastructure that enables additional competitors to enter the generation markets. *Id.* at 1427.

316. *Id.* at 1434.

317. *Id.*

318. *Id.* at 1431.

319. *Id.* at 1432 (*citing* Commission of the European Communities, Commission Staff Working Document Accompanying the Legislative Package on the Internal Market for Electricity and Gas—Impact Assessment (SEC (2007) Final 1179, at 63).

320. *Id.* at 1431.

One observer notes that the main advantage of the ownership-unbundled ITSOs is the elimination of the inherent conflicts of interest associated with vertically integrated utilities.³²¹ While regulatory oversight would still be necessary, the elimination of these conflicts means that the regulation would be less intrusive, and the attention of the network operator could be focused on efficiency of the network and optimizing investments.³²² Another commenter similarly concludes that “ownership unbundling is the simplest, most effective, and stable solution to solve the inherent conflict of interest that so clearly plagues vertically integrated [transmission system operators].³²³ Efforts to strengthen functional unbundling, by focusing on management and information unbundling and compliance programs to avoid discrimination, “is doomed to remain unsuccessful,” according to this commenter.³²⁴

VI. CONCLUSION AND RECOMMENDATIONS

These are extremely challenging issues for regulators and policymakers to tackle. The provision of electric service is an essential function in the U.S. economy, with an increasing expectation—if not requirement—that the electricity supply be reliable and reasonably priced. Massive amounts of additional capital will need to be invested in the utility grid, both at the wholesale and retail level, in the coming years, so it is critical that regulators and policymakers “get it right” in fashioning Utility 2.0, the utility business model of the future. The electric utility business is capital intensive, and utilities must be able to continue to attract, on reasonable terms, the capital necessary to build a 21st century utility network, which in turn requires the confidence of investors that the new Utility 2.0 business model is viable and the regulatory framework is relatively certain and fair.

The “business as usual” approach being followed by a number of PUCs around the nation may provide some short-term relief against the forces that are reshaping the electric industry. But regulators following that path are ignoring the fundamental trends, and run the risk of maintaining the inefficiencies of existing utility practices, to the ultimate detriment of the utility ratepayers they are charged with protecting. The long-term sustainability of the electric distribution utility depends upon timely, decisive actions, as the forces driving these changes—particularly the continuing decline in the cost of DG resources, and the essential need to create a grid that is more resilient in the face of increasingly frequent extreme weather events—will not await the outcome of a protracted debate on the

321. *Id.* at 1425.

322. *Id.*

323. *Id.* at 1440.

324. *Id.*

utility business model. The amount of electricity sales that will be “in play” within the current decade require a sense of urgency to this daunting task.

The design of the Utility 2.0 business model must achieve a number of objectives. A foundational objective is a business model geared toward the provision of nondiscriminatory access to the distribution platform. In order to attract new players and additional investment in the retail electricity markets—to get the “innovators off the sidelines”³²⁵—it is essential that the rules of the game be perceived as fair, and that existing players do not have competitive advantages by virtue of their monopoly power. The current structure of vertically integrated utilities carries with it inherent conflicts of interest as well as the ability of the utility to exercise market power in the operation of the platform, to the disadvantage of potential new entrants into the market.

As discussed in the preceding sections, a number of possible approaches are available to address these issues of market power. Functional unbundling is one approach, which has the advantage of being the least disruptive to the existing utility model and potentially requiring fairly low transaction and transition costs. At the same time, FERC’s experience with the restructuring of the wholesale electricity markets in Order 888 and its ultimate decision in Order 2000 to reject functional unbundling in favor of independent, third-party system operators, suggests that functional unbundling may avoid short-term pain but fails to provide the long-term solution. The EU experience is similar on this point. A recurring theme in evaluating the deficiencies of functional unbundling is the failure to address the underlying conflicts of interest associated with the vertically integrated utility, and the very high compliance costs, as regulators attempt to enforce codes of conduct in a valiant effort to demonstrate to third-party providers that the system is fair. The inability to make the fundamental case that the rules of the game are fair will jeopardize the attraction of new entrants, and associated new investment, into the energy markets. Actual experience suggests that the vertically integrated model, coupled with functional unbundling, will fail to attract the necessary investment to modernize

325. Richard Kauffman, Chairman, N.Y. Energy and Fin., Presentation at PSC Symposium at Albany Law School: Shaping the Future of Energy (May 22, 2014), available at <http://www3.dps.ny.gov/W/PSCWeb.nsf/All/6DB084A00222486285257CE10046E6F8?OpenDocument>.

the network, as utilities will be reluctant to make any investments that enable additional competition in its affiliated lines of business.

Both ownership unbundling—the ITSO model—and the use of independent third party network system operators—the IDSO model—are more effective at addressing the inherent conflicts of interest under the vertically integrated model, but require more fundamental restructuring of the business, with attendant higher transaction and transition costs. Actual experience suggests that either model will require continued vigilant regulation: in the case of the ITSO, to prevent over-investment in the network and, in the case of the IDSO, to ensure that the enterprise does not unnecessarily expand to create an excessive layer of additional costs to be passed on to ratepayers. In this regard, the track record of RTOs in the United States is somewhat unsettling, as the extensive stakeholder process contemplated by FERC as a check on RTO expenditures does not seem to be effective, given the rapid growth in employees and budgets in recent years and the claimed failure to give much consideration to impacts on retail electricity rates.

The IDSO model proposed by Jon Wellinghoff would address this shortcoming to some extent, by subjecting IDSOs to regulation by state PUCs, which should be more effective in providing a check on unnecessary growth in IDSOs. At the same time, the *Track One Proposal* in New York makes a strong point that the function of the IDSOs is largely duplicative of the functions currently carried out by the distribution utilities, and there is some question as to the cost-effectiveness of adding an additional layer of bureaucracy. FERC wrestled with the same issue in its *RTO NOPR*, and concluded that the efficiencies gained by market participants having greater confidence in the fairness of the market structure outweighed the higher administrative costs associated with the operation of RTOs. The same analysis would seem to apply at the retail distribution level.

The design of the Utility 2.0 model is just the first step in the process. Following that determination, regulators must tackle an equally daunting task of designing a regulatory framework that corresponds with the changes in the underlying utility business model, and preserves the long-term viability of Utility 2.0. In order for investors to devote the necessary, vast sums of capital to the industry to create a 21st century utility network, they must have confidence in the predictability and certainty of the regulatory framework. To the extent the range of services provided by the incumbent distribution utility shrinks under Utility 2.0, regulators will be under pressure to create new revenue opportunities for utilities in order to preserve the long-term viability of the utility business model. In any event, the regulatory framework for electric utilities in the U.S. will need to evolve to one that rewards utilities based on their success in meeting their customers' energy needs, rather than on their success in selling more

electricity. Designing this regulatory framework, on the heels of shaping the Utility 2.0 business model, will provide plenty of challenges for regulators and policymakers for the remainder of the decade.